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# Decarbonization and Electricity Market Design: The Future of Mibel as Thermal Generation is Phased out


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# TDSE

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## Executive Summary

This text discusses market design issues related to the expected growth of renewables in the Iberian market[7]. In the coming years both climate policy and cost reductions in renewable generation point in the direction of decarbonizing the electric sector. Many countries, including Portugal and Spain, are committed to aggressive goals for increasing the share of renewables in their generation mix and to eventually build an electric system that is one hundred percent renewable. Markets designs will have to evolve in order deal with this new situation.

From the microeconomic point of view the impact on markets will derive from the fact that renewable generators as a rule only have fixed costs, unlike fossil fuel thermal generators that have both fixed and substantial variable costs. A firm that only has fixed costs has a zero marginal cost, meaning it will be willing to sell its production at any price. If most firms in a market have a cost structure based on fixed costs, prices will be zero or very close to zero whenever these firms' production can meet demand. And if all firms have a fixed-cost only cost structure there will be no short term prices as long as production is able to meet demand.

But even countries that have committed themselves to build an all renewable electric system will only do so in a several years and by then some low emissions variable cost based technologies may be commercially available like green hydrogen or fossil fuel power plants with carbon capture. Short term markets will most likely still be in place many years from now and they will still be giving short term economic signals for supply and demand agents.

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[7] This he article written thanks to two Research and Development (R&D) Projects developed by the Electric Sector Research Group (Gesel), under the Brazilian Electricity Regulatory Agency (ANEEL) R&D Program. The first project "Analysis of the Viability of Pumped Storage Plants in the National Interconnected System" (www.projetouhr.com.br) was financed by the companies Campos Novos Energia, Energética Barra Grande, Companhia Energética Rio das Antas, Foz do Chapecó Energia and Paulista Lajeado Energia. The second project is "Framework Development for Pumped Storage Hydro Power Projects", financed by State Grid Brazil Holdings.

The real world market design challenges are related to the medium term trend for fixed cost generation becoming progressively dominant. As this happens, short term market prices will no longer play the role they are supposed to play in text book competitive markets: i) investments and divestments decisions based only on expected short term market prices may no longer be socially optimal and; ii) there will no longer be an economic driver making short term prices and production costs converge.

Today's markets already include some features that do not belong to text book competitive markets and that partially address those questions, like capacity contracts and government organized auctions for long term renewable generation. But we expect some new challenges and the final parts of this paper analyses two of them.

1) A system dominated by renewable generation requires the widespread introduction of some new technologies that currently lack a proper market framework, the most notable being storage. Storage will be critical both to use excess energy generated when electricity from natural sources (wind, solar and hydro) or inflexible sources (baseload thermal and cogeneration), exceeds consumers' demand and to ensure security of supply in moments where non-controllable generation is very low. The authors argue that an upcoming market framework for storage should take into account that these plants should be dispatched even in situations where marginal costs, and therefore prices, are zero and therefore cannot be optimally dispatched based on short term market prices only.
2) As the generation cost structure becomes more fixed-cost centered, consumers will eventually have energy bills with a strong fixed cost component. The authors investigate how this can happen without eliminating short term market price signals.

Part 1 deals with the basic microeconomic issues related to markets where firms with a fixed cost based cost structure are dominant. Part 2 makes an empirical analysis of price signals in thermal markets (Texas' ERCOT), in fixed cost based markets (Brazil and Colombia) and in transitional markets, such as Mibel. Part 3 reviews electric market design main issues.

Part 4 analyses Spain's plans for decarbonizing the electric sector, based on the National Integrated Energy and Climate Plan (PNIEC). Some findings from a research project on storage are presented that suggest that in fixed cost based systems storage optimal dispatch cannot be defined by short term market mechanisms and finally the authors discuss price signals for consumers in future a fixed cost based electric system.

## **Sumário Executivo** (Portuguese version)

O presente trabalho tem como objetivo discutir os impactos do crescimento esperado da participação de energias renováveis no mercado ibérico de energia elétrica. Nos próximos anos, tanto a política climática, quanto a redução dos custos de geração renovável apontam na direção de um processo de descarbonização do setor elétrico. Neste sentido, muitos países, incluindo Portugal e Espanha, estão comprometidos com metas agressivas para aumentar a participação das energias renováveis em suas matrizes energética e para eventualmente construir um sistema elétrico cem por cento renovável. Desta forma, os desenhos de mercado, eventualmente, terão que evoluir para funcionarem adequadamente nesse ambiente.

Do ponto de vista microeconômico, o impacto sobre os mercados de energia resulta do fato dos geradores renováveis, como regra, só apresentarem custos fixos, ao contrário dos geradores térmicos a combustíveis fósseis que têm custos fixos e variáveis. Uma empresa que só apresenta custos fixos tem custo marginal zero, o que significa que estará disposta a vender sua produção a qualquer preço. Se a maioria das empresas do mercado apresentarem uma estrutura de custos baseada em custos fixos, os preços serão zero ou muito próximos de zero sempre que a produção destas empresas puder atender à demanda. E se todas as empresas tiverem uma estrutura de custos baseada apenas em custos fixos, não haverá preços de curto prazo.

Por outro lado, mesmo os países que se comprometeram a construir um sistema elétrico totalmente renovável, este só será concluído em muitos anos e, até lá, outras tecnologias renováveis baseadas em custos variáveis poderão estar disponíveis, como termelétricas movidas a hidrogênio verde ou com captura de carbono. Os mercados de curto prazo provavelmente continuarão funcionamento por muitos anos e dando sinais econômicos de curto prazo para os agentes de oferta e demanda.

Desta forma, os desafios em termos de desenho de mercado relacionados à tendência de médio prazo da geração baseada em custos fixos se tornar progressivamente dominante. Caso isto aconteça, os preços de mercado de curto prazo deixarão de desempenhar um papel adequado nos mercados competitivos: i) as decisões de investimentos e desinvestimentos baseadas apenas nos preços de curto prazo podem deixar de ser socialmente ótimas e; ii) não haverá mais um motor econômico convergindo  preços de curto prazo e custos de produção.

Os mercados atuais já incluem algumas características que não pertencem aos mercados competitivos e que abordam parcialmente estas questões, como os contratos de capacidade e os leilões organizados pelo governo para a geração renovável. Há também alguns novos desafios e as seções finais deste documento abordam dois deles:

1) Um sistema dominado pela geração renovável requer a introdução de novas tecnologias que hoje carecem de uma estrutura de mercado adequada, sendo o mais notável o armazenamento. O armazenamento será crítico tanto para o excesso de energia gerada de fontes como a eólica, solar e hídrica, quanto para garantir a segurança de suprimento em momentos nos quais a geração não controlável for muito baixa. Os autores argumentam que uma futura estrutura de mercado para armazenamento deve levar em consideração que essas plantas devem ser despachadas mesmo em situações onde os custos marginais e, portanto, os preços, são zero. Sendo assim elas não podem ser despachadas com base apenas nos preços de mercado de curto prazo.

2) À medida que a estrutura de custos de geração se tornar mais centrada no custo fixo, os consumidores acabarão apresentando contas de energia com um forte componente de custo fixo. Os autores investigam como isto pode acontecer sem eliminar os sinais de preços de mercado de curto prazo.

# 1 Microeconomics of markets where fixed cost production is dominant

The microeconomics behind the change in the role played by short term prices brought by the increasing share of fixed cost based renewable generation is quite simple. In competitive markets, price is equal to the marginal production cost (PINDYCK and RUBINFELD, 2005). Marginal costs, in turn, depend basically on variable costs. In firms that do not have significant variable costs, like most renewable generators, marginal costs are zero or very close to zero. And if firms that have only fixed costs are the marginal suppliers, that is, if in a given moment demand can be met only by fixed cost based producers, price will also be zero or very close to zero. If a firm does not incur in variable costs to produce goods or services, it will be willing to sell its production at any price because it is better to have some revenue, no matter how small, than not having any revenue at all (VARIAN, 2008).

But of course, marginal costs maybe zero for firms that have a fixed cost based cost structure, but total costs are not zero: fixed costs (which in microeconomics include capital costs) must be accounted for. A firm that has only fixed costs will prefer to sell its goods for one cent rather than failing to sell anything at all. Nonetheless it will be operating at loss if unit fixed costs are any higher than one cent. To sell at one cent something that actually costs more than that due to fixed costs is to minimize losses. It is a short term rational decision. But, of course, nobody will invest to produce a good if market prices are expected to fall below production costs in the medium or long term.

Text book microeconomics for competitive markets implicitly suppose that firms have both fixed and variable costs, so that an introduction to microeconomics does not have to deal with a special situation where marginal costs are zero. In theoretical competitive markets marginal costs always rise as firms have to rump their production up. When demand surges and firms increase production to meet it, marginal costs rise and this leads to higher prices. Conversely, when demand for a product decreases firms operate at lower production level, marginal costs decrease and this drives prices down (VARIAN, 2008).

In competitive markets variable costs are always recovered because firms will not produce anything in the first place if prices do not cover the costs directly incurred in production. But fixed costs are not passed through to prices. The reason why producers are able to recover their fixed costs in these markets is because they collectively make investments and divestment decisions based on expected profits. When prices are high, firms are able to recover all their costs (fixed and variable) and they manage to have extra profits. This is an incentive for new investments and the first ones to do so will benefit from higher prices. But as more firms invest in new capacity, the structural increase in supply will make each firm operate at a lower production level, reducing marginal costs, and as a consequence reducing prices, margins and profits. Conversely, when there is excess production capacity, firms will not be able to recover fixed costs and this will lead some of them to go out of business. That will structurally decrease supply and each remaining firm will have to rump production up, increasing marginal costs, and therefore increasing prices, margins and profits (VARIAN, 2008).

In the short term there may be imbalances in a competitive market but in the long term prices signal firms to make investments and divestments that will ultimately lead to a situation where prices tend to match production costs. Furthermore, firms make investments in the most cost efficient technologies in order to maximize profits and this cost efficiency will eventually lead to lower market prices, benefitting consumers.

The beauty of this scheme is that each firm's individual production and investment decisions, based only in their selfish interest in maximizing profits or minimizing losses lead in the long term to a socially optimal solution. And this happens with no central coordination and with no direct government intervention.

## 2 Price signals in electricity markets

One can verify whether or not a market behaves like a competitive market should by checking weather prices respond to variable cost changes. In electricity this is easy to do because fuel costs are the main variable cost for the industry and fuel prices are publicly available. If a fuel price change is reflected in electricity prices, the main economic driver that links costs to prices can be verified to be in place.

Brandão *et al* (2020)[8] selected a group of electricity markets in order to verify if variable cost changes (fuel costs) are reflected in wholesale electricity prices. The author's main hypothesis is that in markets with a high share of renewable energy, that is, with very low marginal costs, the behavior of short term prices may give dysfunctional price signals to economic agents as the link between production costs and prices may prove to be missing. A group of markets was selected including thermal markets with a high share of generation with substantial variable costs, and markets with a high share of fixed cost based generation. The following markets were considered: PJM, ERCOT, NEISO, Mibel, NordPool, Brazil and Colombia. While in the American markets (PJM, ERCOT and NEISO) thermal sources are dominant, Brazil, Colombia and NordPool have a large share of hydro generation. Mibel has a more balanced mix, including thermal, hydro and renewables.

An econometric generalized autoregressive conditional heteroskedastic model (GARCH) was estimated for each selected market in order to check the impacts low marginal cost generation and fuel prices in electricity prices.

The marginal cost share of each market was calculated from International Energy Agency data. For fuel prices, the authors used Brent, Mibgas or Henry Hub, depending on the case[9].

[8] Paper submitted to a peer review periodical and yet unpublished. Brandão, R.; Aquino, T.; Alves, A.; Chaves, A. C.; Maestrini, M; Vardiero, P. *Spot prices behaviour in markets with increasing low marginal cost generation*.

[9] Nordpool prices available at: https://www.nordpoolgroup.com/historical-market-data/
Brazilian prices available at: https://www.ccee.org.br/portal/faces/pages_publico/o-que-fazemos/como_ccee_atua/precos/precos_medios?_afrLoop=535625064519274&_adf.ctrl-state=4hdpy94cd_1#!%40%40%3F_afrLoop%3D535625064519274%26_adf.ctrl-state%3D4hdpy94cd_5.
PJM, NEISO and ERCOT prices available at:
https://www.eia.gov/electricity/wholesale/#history,
OMIE prices available at: https://www.omie.es

The selected markets were modelled independently and the time interval adopted was the maximum available at the time as shown in the following table.

**Table 1: Wholesale price series time interval for each market.**

| MARKET | BRAZIL | NORD POOL | PJM | NEISO | ERCOT | MIBEL (ES) | COLOMBIA |
|---|---|---|---|---|---|---|---|
| **START/END** | Aug-01/ Nov-18 | Apr-00/ Oct-18 | Feb-01/Aug-18 | Feb-14/Aug-18 | Feb-14/Jun-18 | Feb-16/Aug-20 | Feb-09/Mar-18 |

Source: Brandão *et at* (2020)

The results of the models are shown in Table 2. The first column shows the market name. The second column "Avg % LMC" is the share of low marginal cost (LMC) generation to total generation. It is not used in the modeling. It is used to order markets from the ones where fixed cost generation is dominant to the ones where fossil fuel generation is dominant. The remaining columns are the results for each market's model:

- $\delta_{p(-1)}$ estimates the% of impact from prices in the previous month in the current month's prices;
- $\delta_g$ is the impact of a 1% variation in LMC generation on wholesale electricity prices;
- $\delta_f$ is the impact of a 1% fossil fuel price (Brent and natural gas, depending on the case) variation in electricity prices;
- $\alpha_0$ presents the intercept of the regression; and
- $R^2$ is the R-squared of the regression.

MIBGAS prices available at: https://www.mibgas.es/en/market-results

**Table 2: Model Results for Selected Wholesale Electricity Markets**

| Market | Avg % LMC | $\delta_{p(-1)}$ | $\delta_f$ | $\delta_g$ | $\alpha_0$ | $R^2$ |
|---|---|---|---|---|---|---|
| Brazil | 89.21% | 0.94*** | 0.27 | -22.1*** | 0.21*** | 0.889 |
| NordPool | 80.89% | 0.93*** | 0.21* | -5.73*** | 0.26*** | 0.851 |
| Colombia | 75.94% | 0.91*** | -0.11 | -5.68*** | 0.34* | 0.799 |
| Mibel (ES)[10] | 68.73% | 0.74*** | 0.43*** | -0,84*** | 1.46*** | 0.857 |
| NEISO (US) | 49.50% | 0.75*** | 0.87*** | -3.92*** | 0.92*** | 0.652 |
| PJM (US) | 30.66% | 0.94*** | 0.67*** | -2.66*** | 0.22* | 0.766 |
| ERCOT (US) | 22.81% | 0.81*** | 0.93*** | -1.1 | 0.64*** | 0.633 |

*** p-value<0.01; **p-value<0.05; *p-value<0.10

Source: Brandão *et al* (2020).

Fuel costs have a very low impact on wholesale electricity prices in Brazil and Colombia, due to a very high share of low marginal cost generation (89.21% and 75.94%). In these markets, the only significant price driver is the low marginal cost generation's share in total generation ($\delta_g$). As short term prices are not related to production costs, they are unable to send long term economic signals for producers.

NordPool countries also have a very high share of low marginal cost generation (80.89%). But prices respond both to low renewable share in total generation and to fuel prices, although $\delta_f$ is significant only at 10% and the coefficient itself if very low: one percent change in fuel prices affect electricity prices in only by 0.21%. Several interconnections between this market and other markets with considerable thermal generation (Netherlands, Germany, Poland and the Baltic countries) may help explaining why fuel prices are significant even with a very high share of low marginal cost generation.

In Mibel (ES), NEISO, PJM and ERCOT, a stronger relationship between fuel price changes and markets price behavior can be observed. However, in the Spanish market, although the fuel prices change coefficient is significant, the fuel price changes do not pass through to electricity prices ($\delta_f$ = 0.43%). NEISO, PJM and Mibel (ES) can be classified as transitional markets as both fuel price

[10] The Spanish case was recalculated for this article based on the Spanish operator's prices and Mibgas gas price. Data was updated to feb/16 to aug/20.

changes and changes to low marginal cost generation are reflected in market prices. On the other hand, ERCOT seems to be an extreme case where fuel price change is the only significant driver to electricity prices and fuel price changes are reflected in short term electricity prices in an almost one to one basis ($\delta_f$ = 0.93%).

The results shown in Brandão et al (2020) indicate that variable costs (fuel costs) do not play a significant role in short term electricity prices in markets with a high share of fixed cost based generation. In extreme cases, the link between production costs and prices – variable costs – seems to be missing, indicating that in markets where fixed cost based generation is dominant prices are not able to send valid signals both for producers and for consumers decisions.

# 3 Electricity markets known issues

Real world electricity markets are not text book perfect competitive markets and governments do play a role in them. Competitive short term electricity markets did not appear spontaneously, but were created and designed to behave in a way that is compatible with the main properties of competitive markets. Both regulators and competition authorities try to prevent anti-competitive behavior – mainly the exercise of market power by large companies – thereby increasing the probability that participants' production and investment decisions will ultimately lead to socially optimal resource allocation with no governmental coordination.

Electricity market design does have some known issues that were addressed in different ways in different markets. We discuss below three of these issues: the missing money problem; the uncertainty about long term revenues in a capital intensive industry and; the lack of convergence between short term prices and production costs that is typical of some markets, as was shown in the previous section.

## *3.1 Missing money problem and capacity mechanisms*

The issue with electricity markets that was first recognized by the literature concerns the economic viability generators with high marginal costs (peaker plants), especially those that have very low probability of dispatch. Despite having high marginal costs, these plants are essential to the security of supply in days of exceptionally high load. Those generators cannot go out of business (like firms with the very high marginal costs eventually would in a competitive market), without jeopardizing security of supply. Nonetheless, the economic signal is clear: if price equals marginal costs and these plants have the highest marginal cost in the system, prices will not, at least in text book competitive markets, be higher than their variable costs and as a consequence they will never recover their fixed costs no matter how small they may be. This is called the missing money problem in the electricity market literature. First spotted by Marcel Boiteux in the 1940's. This problem should be addressed somehow in electricity market design.

In the first electricity markets, Chile and UK, generators received a capacity payment, in addition to the short term price calculated by the system operator using official dispatch software. This capacity payment corresponded to an annuity of the estimated fixed costs of an efficient peaker plant and its purpose was to remunerate generators' fixed costs that would not be recovered otherwise. In many other markets a similar mechanism was also implemented (CASTRO *et al*, 2018).

In recent years, electricity markets tend to use a competitive scheme to fulfill the same goal. The system operator organizes auctions to buy capacity or reliability services from generators, and sometimes also from consumers, paying a fixed price to auction winners. Agents that sell reliability services usually have specific obligations, for instance, generating energy (or reducing demand) minutes after being notified (CASTRO *et al*, 2018). Most electricity markets in the US have capacity or reliability markets, the exception being Texas' ERCOT. In Europe, the UK introduced a capacity market in 2014 and other European markets may do the same in the coming years, following the Regulation (EU) 2019/943 (*On the Internal Electricity Markets*) that treats capacity markets as a last resort option to assure resource adequacy, while at the same time defining a general capacity market framework for countries that are able to show that they need them.

ERCOT implemented a different scheme that also gives generators access to revenues above marginal production costs. In ERCOT prices may rise to very high levels when system reserves are close to critical levels. These high prices (up to USD 9.000/MWh) encourage consumers, through several demand response programs, to reduce load in exceptionally high demand hours. This also solves the missing money problem for generators with high variable costs: in these high demand hours generators will have revenues above their marginal costs and this will allow them to recover fixed costs. A solution in these lines seems to be the preferred option for Europe according to Regulation (EU) 2019/943.

### 3.2 *Long term revenues uncertainty*

The second known issue with short term electricity markets derives from the fact that all investments in electricity generation have large capital costs that are sunk costs, that is, capital invested in fixed assets for electricity generation cannot be used for other purposes, unlike investments in other types of fixed assets, like land, that can be used for many types of crops. This means those investments are a long term proposition and investment decisions require that companies are confident that revenues will be high enough during many years to make the investment worthwhile.

In purely thermal markets this issue may not be an important one. It is not difficult to predict a new generator's margin (net income in relation to revenue), because the fuel to electricity conversion rate of each existing generator is known. One can therefore simulate the system dispatch and calculate which plant will be setting the market price (the marginal generator) at any given moment. The new generator's expected production and expected margin can then be simulated. Of course, market prices themselves are hard to predict. But as these depend on fuel prices, and they affect all thermal generators, it is possible to make an assessment on the new generator's expected margin that will help the investor deciding whether the investment is sound or not.

A good example of market driven investments in thermal electricity production is the transition from coal to gas generation in the US during the shale gas boom. When gas prices plummeted in the US at the end of the first decade of this century, many investors predicted (correctly) that coal plants would be less competitive than gas fired power plants for a long time. The expected revenues in the short term electricity market added to the expected capacity/reliability revenues justified the investments in the new gas fired plants.

But even in thermal markets, expected short term price behavior may not be enough to justify investments on some types of projects. A decision to build power plants that have a fixed cost based cost structure, such as renewable generation, require predictable revenues – something the short term electricity market cannot give. In a thermal market a fossil fuel plant's expected margin (net income relative to revenue) can be calculated with a reasonable accuracy, but the expected net revenue itself depends on the fuel prices and these can fluctuate a lot. This is not serious for a fossil fuel plant, because its costs are highly correlated to electricity market prices, both depending heavily on fuel prices. But it will be difficult to build a business case for projects with costs that are not correlated to electricity prices, namely, for projects that have only fixed cost, like most renewables – except, of course, if they are able to produce energy at such a low average cost that they can remain profitable in almost any fuel price/electricity price scenario (CASTRO *et al*, 2018).

Capacity revenues do not make total revenues predictable in the long term because they are usually small in relation to wholesale electricity revenues. Besides, capacity mechanisms are usually designed as complementary revenues for controllable generation (fossil fuel based) or load (demand response and storage). In some cases non controllable renewable generation do not even qualify for capacity/reliability markets (CASTRO *et al*, 2018).

There are two mechanisms that may be used to make generators' revenues predictable in the long run, both used as an incentive to investments in new plants. The first one is to define feed in tariffs for energy produced by some types of projects. The second one is to create a competitive environment where potential investors compete for contracts that will provide them with predictable revenues (CASTRO *et al*, 2018).

A large part of the current European fleet of renewable generation plants was built using feed-in tariff schemes. But recently competitive mechanisms have been favored in many countries and this is clearly a trend in Europe as the market – and not the government or the regulator – defines the fair price. The UK introduced auctions for contracts for differences in 2014 and several countries are studying or implementing auctions for renewables, including Spain and Portugal.

## 3.3 *Prices not adherent to production costs*

Several countries use long term wholesale electricity contracts to shield consumers from short term electricity prices swings or at least from events where prices may not match average production costs for a long period of time. This is a problem that is not in the European market design agenda but that may become an issue as the generation mix becomes more fixed cost based and market prices lose adherence to production costs.

Chile, Brazil and Colombia are examples of countries that have created a routine of auctions for long term contracts that includes both new and existing generation projects. Although long term contracts do make revenues more predictable for generators (a topic treated in the last section) here there is an additional goal of making electricity prices more predictable for consumers and also more adherent to long term production costs (CASTRO *et al*, 2018).

Predictability of energy costs for consumers was dear to the French marginalist school, as it gives economic signal for consumers' investment decisions that are aligned to long term electricity production costs. But the issue at stake here is that wherever fixed cost based generation is dominant there is specific microeconomic issue that should be addressed by market design: a non-economic driver, the variation in the share of fixed cost generation, can become a major short term electricity price driver, breaking the microeconomic mechanisms that make prices and production costs converge in text book competitive markets. Actually this issue is as old as electricity markets.

In markets where a favorable hydrology (and not lower production costs) drives short term prices down and a draught drives prices up, natural inflows (not production costs) is the main short term price driver. Short term prices can be above or below actual production costs for a very long time – months or even years – leading not only to poor long term price signals for generators and consumers, but also to wealth shifting between agents. For instance, spot prices may be very low because of a favorable hydrology at a time when the system is in need of investments in new capacity and therefore prices will not reflect production costs nor will they be signaling the need for new capacity. Conversely prices may be very high due to an unfavorable hydrology even when there is excess capacity in the system. And agents will make gains or losses in these situations while the price mechanism does not give correct economic signals for agents' long term decisions that would eventually balance the market.

The first electricity market, Chile, was created in a system where hydro generation was very important. It was therefore subjected to swings in thermal generation from year to year and large variations in average short term prices were also to be expected. Chile's original wholesale electricity market was designed so that consumers were shielded from short term electricity prices. Generators sold electricity to distribution companies in contracts where the electricity price was indexed to medium term (four years) expected marginal costs, calculated by the system operator using official software. The short term market was restricted to generators. In this short term market generators could buy and sell electricity at a price based on the short term marginal cost in order to fulfill their contracts with distribution companies. Therefore, generators managed the short term price risk hedged on their own generation capacity.

This market design, similar to Norway's before the creation of NordPool (bilateral contracting and generators-only spot market), was not long lived. It did not resist a severe draught. In 1999 short term prices were much higher than long term contract prices and this led generators to refuse to participate in auctions for long term contracts with distribution companies. This led to a regulatory change that exposed consumers to the short term prices: they now buy at the spot market energy that cannot be supplied through long term contracts.

Brazil introduced in 2004 a routine of long term auctions for regulated consumers. This includes both auctions for new projects and auctions for electricity from existing projects. Contracts for new projects are tailor made for each class of project (hydro, wind, solar, biomass, fossil fuel thermal, etc.) and some of these contracts do transfer price risks to regulated consumers. Contracts for existing projects usually have fixed prices, the same applying (at least that was the original idea) for contracts for either new or existing hydro projects. As hydro generation is dominant in Brazil, this was supposed to shield regulated consumers from short term price variations.

Like Chile's, Brazil's original market design did not resist to a severe draught. The second half of 2012 saw the beginning of long sequence of dry years that lasted until 2021. Short term prices during this long period of time were on average very high and they remained high even when demand stalled due to an economic crisis in 2015[11]. As a consequence, hydro plants that had sold energy through fixed price contracts and could not deliver the energy they were supposed to due to the draught, had to buy energy in the short term market at very high prices in order to fulfil their contracts. They eventually sought and obtained legal protection from paying their short term market obligations. This legal imbroglio, which was only fully settled in 2022, led the government to change the risk allocation, transferring a large part of the short term price risk from hydro generator to consumers, in exchange for discounts in the contract prices.

In Colombia the regulator, *Comisión de Regulación de Energía y Gas* (CREG), organizes auctions for Firm Energy Obligations (*Obligaciones de Energía Firme*, OEF). Existing and new generators can participate in the OEF auctions and the winners have a stable remuneration, financed through a levee charged from consumers. In exchange, the generator has the obligation to deliver energy when short term prices exceed a threshold defined by CREG called Scarcity Price. This effectively protects consumers from short term price spikes as they do not have to pay more than the scarcity price for electricity when short term prices exceed this threshold. This OEF mechanism is similar to a capacity market with the added feature that it caps prices to consumers: generators will either deliver the energy associated to the OEFs they have sold or buy electricity at the spot market to fulfill their OEF obligations (XM, 2020)[12].

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[11] From 2015 onwards, Brazil's system has high short term prices and generation overcapacity at the same time. This is a good example of a fixed cost based system where short term prices do not give a good signal for long term capacity needs. Overcapacity occurred because many new generation projects were built anticipating a demand increase that failed to materialize. In 2020 prices are finally down to low level but this is due in large part to the Covid-19 economic crisis that reduced demand yet again, increasing the overcapacity problem. In 2021 very dry year brought the system again close to rationing.

[12] During the 2015-2016 El Niño dry period this scheme was put to a real world stress test when spot prices skyrocketed for a long period of time. Some thermal generators with high variable costs were unable fulfill their OEFs because the scarcity price did not cover their fuel costs. This lead to a reform where generators are now subject to financial supervision in order to evaluate whether they can actually fulfill their obligations in a period of severe price stress (SUPERVICIOS, 2017).

With this added obligation for generators, revenues from OEF tend to be higher than traditional capacity market revenues which is a boon for financing new generation projects in an environment of hard to predict prices.

## *3.4 Electricity markets in Europe*

The creation of Europe's internal electricity market is a long term project. Local electricity markets, frequently including more than one country, were the first step for the European internal market. Increasing trans-border trade and progressively converging market rules are slowly making market prices converge. Day-ahead markets, intraday markets and more recently balancing markets have been integrated creating the world's largest energy market. But initially European regional markets were not tightly integrated and even today there are many differences in market design.

For some time UK's 2001 *New Electricity Trading Arrangements* (NETA) was considered the model for European (and to a lesser extent international) electricity markets. From the microeconomic point of view UK's NETA emulated a competitive market designed around a short term electricity market. Long term contracts that were important during in the gas generation boom in the early years after the UK electricity reform were abolished together with capacity payments for generators. Short term prices were supposed to give sufficiently strong price signals for agents' long term decisions.

Other European markets were structurally similar to UK's NETA and in principle short term prices were supposed to guide both short term and long term decisions. But sooner or later many issues mentioned in previous sections had to be addressed. Renewables were promoted by feed in tariffs and more recently through auctions – two different ways of addressing the same problem, which is, providing fixed cost based generation projects with predictable revenues. Capacity mechanisms were also introduced in some countries in order to assure that the system operator have enough controllable generation to match generation and demand in real time (system adequacy).

Nonetheless, the very existence of the European internal electricity market relies on short term electricity markets and this part of the European internal electricity market is now tightly integrated. Short term markets are essential to organize production decisions not only in the local markets but across regional market boundaries.

Therefore the existence of wholesale electricity markets and the need for short term market prices that are well formed (free not only from market power influences, but also, whenever possible, from regulatory intervention and from differences between local regulatory environments) are not in question. European electricity markets are here to stay. But this does not mean that their design will not change over time.

The main microeconomic driver for these changes will be the shift towards a generation mix where fixed-cost based renewable generation will become dominant. This is very likely to happen as both climate policy and cost reductions in renewable generation point in the same direction: a fast renewable generation growth.

Mibel will most likely be one of the first European regional electricity markets where the shift towards a fixed cost based supply mix will bring the need to adapt the market design. There are several reasons that lead one to believe that in this aspect Mibel will be ahead of other European market:

- Spain and Portugal have a good potential for solar and wind generation;
- Both countries have set ambitious goals for decabonization and for renewable generation growth;
- There already exists long term auction schemes for renewable plants that proved attractive for investors; and
- Transmission congestion with France is not expected to be eliminated at least for the next ten years, causing excess Iberian renewable generation to reduce prices in Mibel instead increasing exports for the rest of Europe. This will accelerate the trend towards very low spot prices in Mibel, at least in hours of excess generation.

In the following section analyses *Spain's Plan Nacional Integrado de Energía y Clima 2021-2030* in order better evaluate Mibel's fast transition to a supply mix where fixed cost based technologies will be dominant.

# 4 Decarbonization and electricity market design – the Spanish case

In the next sections, Spain's climate policy and energy policy for 2030 are analyzed, followed by a discussion about the main challenges that the long term goal of having a renewables only electrical sector brings for electricity market design and system dispatch.

## *4.1 Spain decarbonization goals for 2030*

The Spanish climate policy's foundations are the goals and guidelines established at the 21st Conference of the Parties (COP21), also known as the Paris Agreement. At the European level European Union has released a package of measures to increase the share of clean energy, with several binding principles to be achieved by 2030 by the member states, such as: i) 40% reduction of greenhouse gas (GHG) emissions in relation to 1990; ii) 32% of renewable energy in relation to total primary energy consumption; iii) 32.5% increase in energy efficiency; and iv) 15% of electricity interconnection between member states.

At the national level, the European Union requires each member state to develop a National Integrated Energy and Climate Plan (PNIEC), addressing strategies designed to achieve their objectives. Following the European Union guidelines, by 2030, the Spanish PNIEC 2021-2030 aims to: reduce GHG emissions by 23%; have 42% renewable energy in final energy use; increase in energy efficiency by 39.5% and; generate 74% of electricity generation using renewable sources. In a long-term horizon, the main objective is to transform Spain into a country with zero carbon emission until 2050.

Spain is expected to reduce total gross $CO_2$ emissions from 319.3 $MtCO_2$-eq in 2020 to 221.8 $MtCO_2$-eq in 2030. A large part of the emissions reduction will come from electricity generation: a decrease of 36 $MtCO_2$-eq or 37% of total GHG emissions reduction.

Most of the expected emissions reduction in the electric sector will come from the phasing out of carbon generation. Table 3 shows the evolution of $CO_2$ emission levels (ton) by productive sector from 1990 to 2030.

**Table 3: Evolution of the $CO_2$ emission levels (ton) by productive sector.**

| Years | 1990 | 2005 | 2015 | 2020* | 2025* | 2030* |
|---|---|---|---|---|---|---|
| Transport | 59,199 | 102,310 | 83,197 | 87,058 | 77,651 | 59,875 |
| Generation of electricity | 65,864 | 112,623 | 74,051 | 56,622 | 26,497 | 20,603 |
| Industrial sector (burned) | 45,099 | 68,598 | 40,462 | 37,736 | 33,293 | 30,462 |
| Industrial sector (process emissions) | 28,559 | 31,992 | 21,036 | 21,147 | 20,656 | 20,017 |
| Residential, commercial and institutional sectors | 17,571 | 31,124 | 28,135 | 28,464 | 23,764 | 18,397 |
| Livestock | 21,885 | 25,726 | 22,854 | 23,247 | 21,216 | 19,184 |
| Crops | 12,275 | 10,868 | 11,679 | 11,382 | 11,089 | 10,797 |
| Waste | 9,825 | 13,389 | 14,375 | 13,657 | 11,932 | 9,718 |
| Refining industry | 10,878 | 13,078 | 11,560 | 12,330 | 11,969 | 11,190 |
| Other energy industries | 2,161 | 1,020 | 782 | 825 | 760 | 760 |
| Other sectors | 9,802 | 11,729 | 11,991 | 12,552 | 11,805 | 11,120 |
| Fugitive emissions | 3,837 | 3,386 | 4,455 | 4,789 | 4,604 | 4,362 |
| Use of products | 1,358 | 1,762 | 1,146 | 1,236 | 1,288 | 1,320 |
| Fluorinated gases | 64 | 11,465 | 10,086 | 8,267 | 6,152 | 4,037 |
| Total | 287,656 | 439,070 | 335,809 | 319,312 | 262,675 | 221,844 |

*The 2020, 2025 and 2030 data are estimates of the PNIEC target scenario.
Source: Ministry of Ecological Transition and the Demographic Challenge, 2019.

Table 4 shows the evolution of installed capacity in Spain according to PNIEC 2030's Target Scenario, showing a strong increase in renewable energies, notably wind and solar and the phasing out of coal and part of nuclear capacity. Note that by 2030 Spain's wind installed capacity (50.3 GW) is expected to be larger than peak load (47.7 GW) while solar photovoltaic installed capacity is expected to be 39.2 GW, 82% of peak load. Therefore, the system will have a large amount of non-controllable generation that in favorable conditions may exceed load even with no contribution from other kinds of generation projects. Total installed capacity is expected to be 160.8 GW, more than three times peak load. In order to build this system, Spain PNIEC will use a strategy of technological neutrality and cost-efficiency.

**Table 4: Evolution of installed capacity in Spain, Target Scenario 1990-2030, in MW**

| Parque de generación del Escenario Objetivo (MW) | | | | |
|---|---|---|---|---|
| **Año** | **2015** | **2020*** | **2025*** | **2030*** |
| **Eólica (terrestre y marítima)** | 22.925 | 28.033 | 40.633 | 50.333 |
| **Solar fotovoltaica** | 4.854 | 9.071 | 21.713 | 39.181 |
| **Solar termoeléctrica** | 2.300 | 2.303 | 4.803 | 7.303 |
| **Hidráulica** | 14.104 | 14.109 | 14.359 | 14.609 |
| **Bombeo Mixto** | 2.687 | 2.687 | 2.687 | 2.687 |
| **Bombeo Puro** | 3.337 | 3.337 | 4.212 | 6.837 |
| **Biogás** | 223 | 211 | 241 | 241 |
| **Otras renovables** | 0 | 0 | 40 | 80 |
| **Biomasa** | 677 | 613 | 815 | 1.408 |
| **Carbón** | 11.311 | 7.897 | 2.165 | 0 |
| **Ciclo combinado** | 26.612 | 26.612 | 26.612 | 26.612 |
| **Cogeneración** | 6.143 | 5.239 | 4.373 | 3.670 |
| **Fuel y Fuel/Gas (Territorios No Peninsulares)** | 3.708 | 3.708 | 2.781 | 1.854 |
| **Residuos y otros** | 893 | 610 | 470 | 341 |
| **Nuclear** | 7.399 | 7.399 | 7.399 | 3.181 |
| **Almacenamiento** | 0 | 0 | 500 | 2.500 |
| **Total** | **107.173** | **111.829** | **133.802** | **160.837** |

*The 2020, 2025 and 2030 data are estimates of the PNIEC target scenario.

Source: Ministry of Ecological Transition and the Demographic Challenge, 2019.

Spain currently has a generation fleet with 26,612 MW of combined cycle thermal units. These gas plants together with demand response and storage will ensure energy security and system flexibility in a system where non controllable renewables will be responsible a large part of electricity generation. The 2030 PNIEC estimates an additional storage capacity (6 GW) will be in place by 2030, consisting in batteries and new pumped storage plants, supposing both technological and regulatory framework innovations.

With regard to the transmission system Spain falls below the interconnection rate target set by the European Union (currently 3% of total installed capacity versus a 10% target for 2020). If one considers the new interconnections already planned, Spain will reach 3GW transfer capacity with Portugal and 8GW with France, falling below the 15% EU target for 2030.

In order to achieve the planned renewable generation targets for the electric for 2020, a series of incentive measures and policies were adopted, such as the creation of a specific remuneration schemes for the production of renewable energy, high-efficiency cogeneration and waste. Recently Spain introduced auctions for new renewable plants.

In accordance with the 2018/2001 Directive, which deals with encouraging the participation of renewable energies, PNIEC 2030 points out that auctions will be the main instrument for promoting renewable generation, assuring predictable and stable income that will facilitate investment decisions and financing. In 2016, the first renewables auction was held. The first three auctions added a total of 9,292.4 MW of renewable capacity to the electrical system (PNIEC).

Auction design should consider the following factors:

i) the reduction of market prices when renewable generation is high;

ii) curtailed energy in moments were renewable generation exceeds load; and

iii) the occurrence of socio-environmental conflicts in some projects. According to article n.6 of the 2019 Climate Change and Energy Transition, the planned installed capacity may be reviewed in order to adjust the decarbonization rate of the energy system.

## *4.2 Red Eléctrica de España's simulations for 2030*

In Red Eléctrica de España (REE) developed dispatch simulations for the PNIEC 2030. In PNIEC Target Scenario where the 2030 goals are strictly enforced, combined cycle gas plants will be the only generators with significant variable costs in Spain by 2030. They will have a total installed capacity of 27.6 GW, more than half of Spain's peak demand (47.8GW). Yet they will produce just 9% of total electricity generation with a capacity factor of 12.8%. Therefore they will be essentially back-up plants for moments when non controllable renewable generation and imports will not prove sufficient to meet demand. The share of fixed cost based generation in total generation will be 91%, very similar to Brazil's as seen in section 2.

But unlike Brazil, where hydro has the largest share of total installed capacity, in Spain wind and photovoltaic solar will have 87GW installed capacity by 2030 (56% of total) in the target scenario. The combined wind and solar capacity alone will exceed Spain's peak demand by 82%. Those plants are not controllable and operate at a small capacity factor, being responsible for 57% of

Spain's total generation in 2030. 5GW of thermal solar plants with 9hs of storage are also expected to go online, adding flexibility to the system and accounting for 5% of total generation. If one adds hydro and other renewables, 78% of Spain's total generation will be renewable by 2030. On the non-renewable front, combined cycle, nuclear and cogeneration, the last two fixed cost/inflexible generation technologies, account for the rest of the electricity balance (9%, 7% and 6% of total generation).

In some hours renewables' generation added to other inflexible plants' generation will exceed consumer demand and export capacity by a large margin. In order to avoid massive curtailment, storage will be an essential part of the Spanish system. Storage will also act as backup for moments of low renewable generation. Pumped storage will be increased to 7.9GW and 2.5GW of batteries will be added to the system, these plants accounting for 21.8% of peak demand. Even so, REE expects curtailment of 6.6% of potential wind and solar generation (including PV and thermal solar, both with and without storage). This represents 4.5% of total generation or half the expected combined cycle generation.

With a large fixed cost based generation fleet, that according to microeconomic theory will be supply electricity at any price, Spain will become a net electricity exporter. Net Exports to France will be 8.8% of Spain's total generation while net exports to Portugal will be 4% of total generation (exports totaling 12.8% of total generation). Exports to France would probably be much larger if not for an expected persistent congestion in the ES to FR international links (congestion 53.2% of the time). Congestion on the ES to PT links FR to ES are not expected to be frequent (8.6% and 8% of the time) and congestion in the PT to ES link will occur only exceptionally (0.7% of the time). Frequent congestion in the 8GW links to France will not only limit exports. It will also result in short term prices in Spain to be € 23.4/MWh lower than in France.

With a fixed cost based generation fleet by 2030 Mibel short term prices will most likely will no longer show a significant correlation to fuel prices. Worse than that, prices will reflect marginal costs from only a small part of the generation fleet and just in some hours: they are not expected to reflect average production costs.

### *4.3 Towards a 100% renewable electric system*

Spain is committed to fully decarbonizing the economy by 2050 and to achieve a 100% renewable electric system. This means the end of nuclear generation, gas cogeneration and, more important for our subject here, combined cycle gas plants. This will eliminate the part of the generation fleet that will still have significant marginal costs by 2030. But does this mean that prices in Mibel will eventually be zero all the time? And how will the system be dispatched when prices start being zero for long stretches of time?

Regarding the first question, the answer is no, short term prices will probably not be zero all the time even if the generation fleet becomes fully renewable. One should considerer that even if Spain has a supply mix that is 100% fixed cost based, prices may be positive if plants with significant variable costs are still used in the neighboring systems. In this scenario Spain would be a net exporter and prices would only fall to zero in moments of congestion in the exporting links.

A second reason for having positive prices may be demand response. If the system is structurally tight on reserves (like Texas's ERCOT is) in hours of high demand or low non controllable generation, reducing demand may be necessary and one way of doing so is through markets mechanisms where consumers are payed to refrain from using energy from the grid. But one should point out that this is more easily done in an isolated system such as ERCOT. As Spain's interconnections are expanded demand response will make sense only if reserves are tight across a group of countries. Demand response will still be an option but an international demand response scheme should be in place. One should also consider that storage may also compete with demand response. Storage can be introduced to reduce curtailment in a system with a large share on non-controllable generation while at the same time it increases system reserves, therefore reducing or eliminating the need for demand response.

Finally, some renewable technologies have significant variable costs like wood biomass generation. This will also be the case of future green hydrogen or carbon capture thermal plants.

These technologies are not expected to play a role in the Spanish system by 2030, but they may be important beyond 2030 in a fully renewable system. If either Spain or its neighbors incorporate plants with these technologies, prices may never be zero.

It remains that even if short term prices are seldom zero by 2050 due to a combination of the factors mentioned above, short term prices are unlikely to reflect average production costs as the vast majority of generators will have a fixed cost based cost structure. In fact this will already be the case by 2030 in Spain if REE target scenario for 2030 comes true. This will require that market design is adapted in order to send long term economic signals both to producers and to consumers (see section 4.5).

Regarding the question about dispatch in a system where marginal costs may frequently be zero, either the system operator or other neutral agents may at the very least play a supporting role to short term markets in defining dispatch.

The first issue is how to define which generators will be curtailed. Prices are zero or as close to zero as regulation allows because generators that have only fixed costs are bound to accept any price, no matter how small, for selling their production. But supply may be larger than demand and there must be a way to decide which generators will operate and which ones will be curtailed. This choice can conceivably be made by the system operator, although in some circumstances negative prices may also do the job.

Prices may become negative if some generations are willing to pay in order to be able to generate. This is usually happens when many generators have priority dispatch (like renewables have in several countries) and baseload thermal plants prefer to pay not to be curtailed. They do so because once a baseload plant is shut down, it takes several hours to rump production up again, and during this time revenue is lost[13]. In 2050 today's nuclear baseload generators will probably no longer be operating and this motivation for negative prices will no longer exist. Besides, priority dispatch for renewables will not be feasible in a system where all generation will be renewable.

[13] Long term physical contracts or feed-in tariff schemes where payments are related to actual generation may also lead some generators to be willing to pay in order to avoid being curtailed and thereby loosing feed-in or contract revenues.

It remains that if generators don't lose money when they are curtailed, prices will never be negative and the system operator – and not the market – will have to decide which plants will be allowed to generate.

There is a second issue about economic dispatch in a system where generation is fixed cost based that is far more important than choosing which generators will be curtailed at a given time, namely, storage. In a future system with a large share of intermittent generation, storage will be essential both to reduce curtailment and to act as backup for moments where supply is tight. Pumped storage hydro is the main storage technology today, but batteries are expected to be introduced in the coming years both at grid level and for distributed use. The important question here is how storage will be dispatched in a fixed cost based system where prices may be zero more or less frequently.

Today grid level storage dispatch is defined by short term markets. Grid level storage plants participate in the day-ahead and intraday markets and due to their inherent flexibility they are also very active in ancillary services market. Their main source of income is usually arbitrage – that is buying electricity in hours of low prices and selling in hours of high prices. Of course, the price spread has to be high enough to obtain a positive margin after accounting for the losses inherent to storage.

The question is how storage dispatch is to be defined in a system where all generation is fixed cost based. At a more fundamental level, one should consider the nature of a storage project cost structure. At first sight it appears that storage has variable costs as one has to buy electricity in order to store energy. But that is true only when the short term price is greater than zero. If one is storing electricity that would otherwise be curtailed, price will be zero and storage will not have a variable cost. This means that whenever fixed cost generation is plentiful it will be possible to store energy at no cost. That is the easy part of the problem, but how about generating? Does it make sense to use stored energy when prices are zero? And how should a storage plant operator be dispatched when market where prices may frequently be zero?

## 4.4 Storage in a system where fixed cost based generation is dominant

A proper assessment on the storage dispatch for the future decarbonized Spanish System would involve building a model similar to the one REE used for the PNIEC 2030 dispatch simulations. The authors did not have access to REE's model, but they have developed research projects that include dispatch modeling in Brazil's system for the 2030's, that is, a system with massive fixed cost based generation and grid level storage (BRANDÃO 2021)[14]. These research project's preliminary findings may give some interesting insights on the role storage can play in a fixed cost based system that may be useful for an upcoming discussion on the Spanish regulation for storage operators.

The model REE uses for simulating the European and Spanish systems is similar to the one the authors used for the research project on pumped storage in Brazil, both models using the same electric system simulation software – Plexos, by Energy Exemplar. Both models calculate the optimal economic dispatch by minimizing the system's total variable costs, that is, by minimizing variable costs for all thermal plants. Optimal system expansion is calculated by minimizing total costs, that is, investment and variable costs. It is assumed that thermal plants bid their true variable costs at the electricity market and that all non-thermal plants have zero variable costs. It should be stressed that the model do not reproduce an actual electricity market and it calculates marginal costs and not proper market prices. Of course, if the market is perfectly competitive, prices will be equal to marginal costs. And if the real world market do have some imperfections, as real markets always do, real world prices still are not supposed to stray far from marginal costs, and market based dispatch cannot be much different from an optimal cost minimizing dispatch. Because if this happens one will be authorized to say that there is a serious market design or implementation flaw.

[14] The project "Analysis of the Viability of Pumped Storage Plants in the National Interconnected System" (www.projetouhr.com.br) was developed under the Brazilian Electricity Regulatory Agency (ANEEL) R&D Program. It is financed by Campos Novos Energia, Energética Barra Grande, Companhia Energética Rio das Antas, Foz do Chapecó Energia and Paulista Lajeado Energia. The second ANEEL R&D Project is "Framework Development for Pumped Storage Hydro Power Projects", financed by State Grid Brazil Holdings.

Brazil's generation fleet has been fixed cost based for a long time, hydro still consisting in more than 60% generation capacity today, down from over 80% in the beginning of the century. Conventional hydro storage capacity is very large (210TWh) and it is essential to ensure supply security in dry years. Zero marginal costs are a real possibility in Brazil. As an example, from 2003 to 2011 (that is, before the recent multiyear hydrological crisis) the average weekly marginal cost in the South-East submarket (the largest submarket) was zero in one out of five weeks. This meaning that no thermal plant with a variable cost larger than zero was needed in 20% of the weeks.

Thermal capacity with variable costs had a negligible share of system capacity until the end first decade of this century. Recently some gas and oil plants were added, more as backup for dry years than for primary energy production.

Brazil has a very large wind and solar potential that can be explored at costs that are way below fossil fuel generation. In government organized auctions for new generation projects, onshore wind has proved for several years to be very cost effective. This is a consequence of good wind resources: the average measured capacity factor for onshore wind farms in Brazil exceeds 42% (www.ons.org.br), an outstanding number by international standards. In recent government organized auctions PV solar projects have also proved to very competitive. In the coming years wind and solar are expected to be responsible for most new generation, chosen based on economic criteria only, that is, even with no climate policy induced contracting.

This trend for wind and solar growth, together with the sluggish expected expansion of hydro capacity will eventually create a need either for new thermal generation to act as backup for non-controllable generation or for storage. Storage does seem the best alternative for a clean electric system. But there is currently no dedicated storage plant in Brazil, neither is there a commercial model for dedicated storage in place, the result being that there is still no plan to introduce dedicated storage plants of any kind. In order to advocate for a change in the grid or wholesale market regulation that makes storage attractive for investors one should prove first that storage is economically viable through developing a least cost system expansion for Brazil's future system.

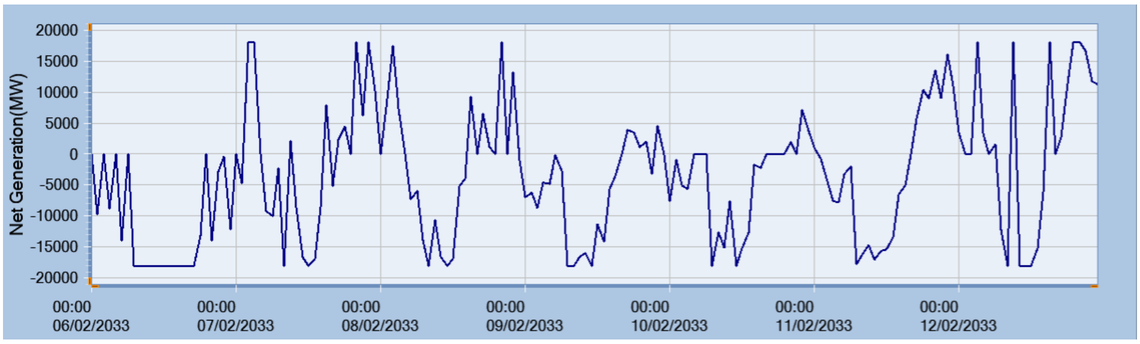
The research team modelled Brazil's planned electric system in Plexos, according to Brazil's official Ten Year Plan (Plano Decenal de Energia, PDE 2029, developed by Empresa de Pesquisas Energéticas, EPE). Plexos was chosen because it excels in representing variable generation and storage even in medium/long term simulations. Beyond 2029 the least cost system expansion chose wind and solar generation as primary energy sources. Security of supply is to be assured by a combination of pumped storage and gas fired power plants.

The dispatch simulation for the resulting system is very interesting not only for a Brazilian discussion on a future storage commercial framework but also for the European discussion on storage regulation. The system modeled for Brazil beyond 2029 goes through a massive growth in wind and solar, not unlike the one that is projected for Spain until 2030.

The first interesting insight is that in a cost minimizing dispatch, pumped storage plants operate both for storage and for generation during periods where marginal costs are zero. The illustration bellow shows net generation from a set of hypothetical pumped storage plants with a combined 18GW installed capacity each with 480hs of storage, during a week in 2033, extracted from a three year simulation. The graph was plotted from a sample where a favorable hydrology led to a very small thermal plant usage. In many moments, like in the week portrayed below, the system uses only fixed cost based generation and prices (marginal costs) are zero.

To read the graph note that when net generation is positive, pumped storage plants are generating and when net generation is negative pumped storage plants are storing energy.

**Graph 1: Pumped Storage**
**Hourly net generation in one week with zero prices (in MW)**




Source: Gesel, Pumped Storage Viability for the Brazil's National Interconnected System (www.projetouhr.com.br).

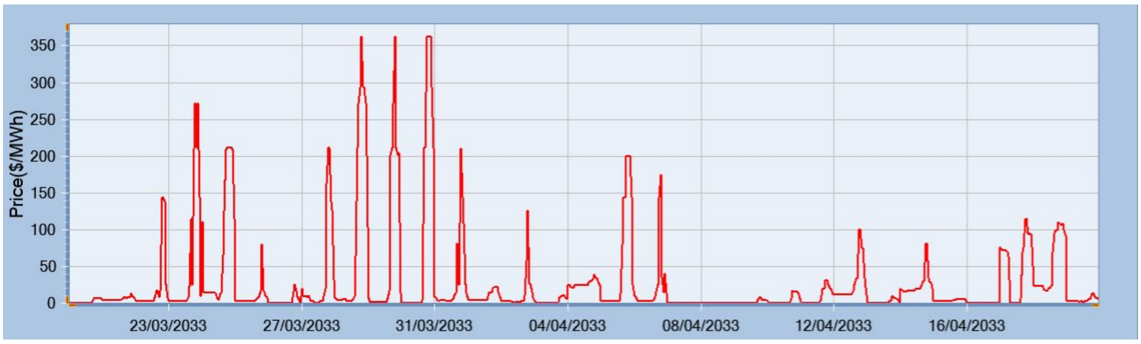
The authors fail to see how a short term market based dispatch would produce a storage dispatch in any way similar to the one reproduced above.[15] While storing energy when prices are zero is all too natural, why would the storage operator switch from storing energy to generating if prices are zero all the time? And why would it generate some precise amounts of energy at precise hours if prices are always zero?

Prices may be zero during the week pictured above, but storage dispatch is not random. It is calculated to minimize total system costs in a three year simulation. During this three year period the average price is very low, but most of the time price is not zero and some fossil fuel power plants do generate. The next few graphs show role storage plays in minimizing costs.

The graph below shows prices, calculated based on marginal costs, for a period of one month extracted from the same hydrological sample, but this time with the system modelled with no storage device. Note that prices are either zero or very low for most of the month but there are several spikes when thermal plants are needed to meet demand.

[15] In Brazil and in other Latin American countries, dispatch is cost based. The system operator uses software that calculates the optimal dispatch and marginal costs. Hydro plant owners do not determine production. They are told by the system operator when and how much to generate. When there is an excess of energy in the system, usually in a moment of favorable hydrology, marginal costs are frequently zero. In these moments hydro dispatch is far from random: the system operator, dispatches hydro plants in order to storage extra energy in an optimal way.

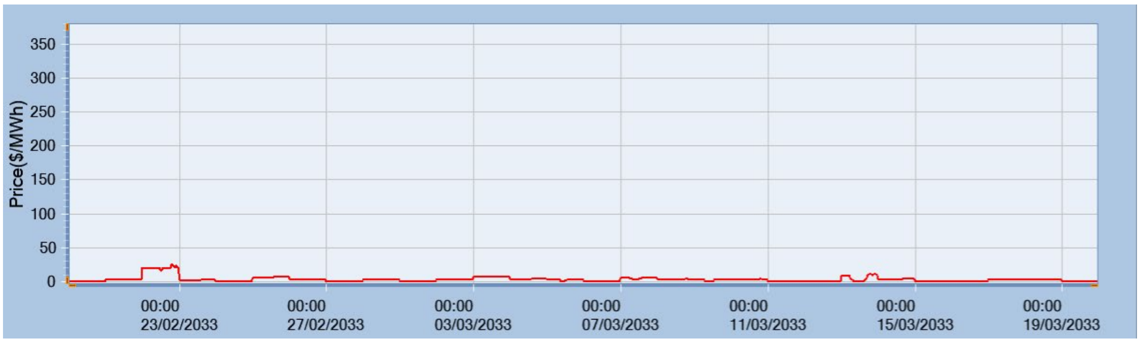
**Graph 2: Prices with no Pumped Storage (in BRL)**




Source: Gesel, Pumped Storage Viability for the Brazil's National Interconnected System (www.projetouhr.com.br).

The graph below shows prices in for the same one month period when storage (18GW, 480hs) is reintroduced. Average prices over the three year period are almost halved in relation to the simulation in the previous graph, and in this particular month prices are now very low all the time, although they are usually not zero. There are no longer price spikes as conventional hydro and pumped storage are able to meet peak demand. The low prices are compatible to baseload generators being dispatched.

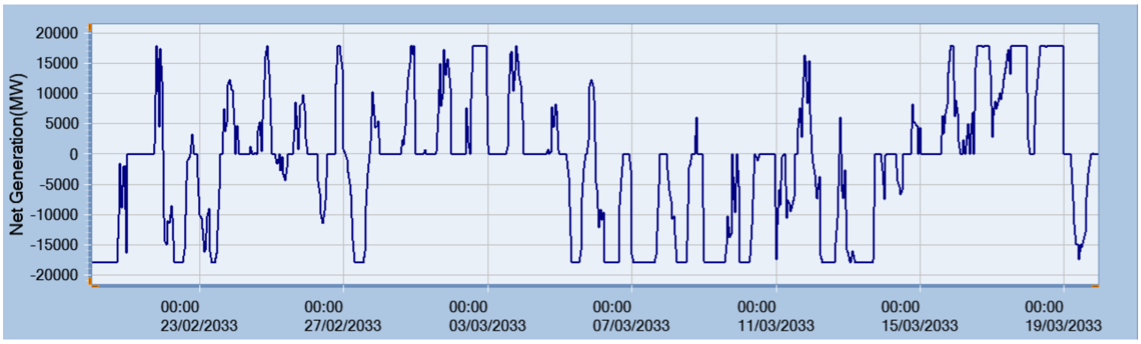
**Graph 3: Prices with Pumped Storage (in BRL)**




Source: Gesel, Pumped Storage Viability for the Brazil's National Interconnected System (www.projetouhr.com.br).

The graph below shows pumped storage dispatch during the same one month period pictured before. This graph too has some interesting information. Note that at the end of March the 2nd, pumped storage plants are dispatched at full capacity. In these hours there would be a price spike were it not for the introduction of pumped storage plants that actually displace thermal power plants thereby reducing prices (see Graph 2). But in the following day, March the 3rd, prices are slightly higher but pumped storage plants are no longer generating. Why did they generated at full capacity for a given price and failed to dispatch in the following day when at a higher electricity price?

**Graph 4: Pumped Storage – Net Generation (in MW)**




Source: Gesel, Pumped Storage Viability for the Brazil's National Interconnected System (www.projetouhr.com.br).

One should stress that these storage plants' dispatch was calculated to minimize total system costs and not to maximize plant owner's profits. In some simulations (not in the ones pictured here) storage plant's net revenue was negative over a three year period even in deterministic simulations, meaning that minimizing system costs in some cases can only be achieved if energy valued at a perfect market price would generate a loss for a storage plant owner that decided to follow a system cost minimizing storage dispatch.

It remains to be seen whether a price driven storage dispatch in a system where prices are always positive is compatible with an optimal dispatch or not. Also, one cannot jump to the conclusion that storage dispatch for the Spanish by 2030 and beyond would have the same characteristics of an optimal storage dispatch for the future Brazilian system. But as the Iberian electric system is bound to become more and more a fixed cost based electric system, it is highly recommended that an upcoming storage operator commercial framework be defined in a way that one can be sure storage dispatch will be compatible to cost minimizing dispatch. Otherwise one risks introducing a market design flaw. An alternative framework to pure price based dispatch may have to be devised if an efficient storage dispatch can become a reality.

## *4.5 Consumer electricity price signals in a fixed cost based system*

Our last topic for reflection relates to price signals for electricity consumers in a system where fixed cost generation becomes progressively dominant.

In any sound market design, electricity price for consumers, both large and small, should reflect production costs. Not necessarily in the short term, that is, hour to hour, but definitely in the medium to long term. Prices below production costs are not sustainable for producers and prices systematically above fair production costs are socially unacceptable. So, as production costs become more and more fixed cost based, is only too natural that consumer electricity bills should reflect this, that is, they should become less volatile. The big question is how to achieve this without eliminating price signals for consumers.

In many countries market design went a long way in the direction of assuring predictability in electricity costs for consumers in the long run. This trend is especially conspicuous in countries where electricity production is hydro dominated as there is a trend to alternate between long periods of very high prices and long periods of very low prices, basically because hydrology happens to be favorable or unfavorable in a given period. Although it is only too natural to have high market prices for a good that is scarce at the moment, this is not socially justifiable if high prices do not send correct economic signals do both producers and consumers. High short term prices for consumers give a correct short term economic signal for them to refrain from consuming a good that proves to be scarce. But the same may not apply to producers. In a dry period high prices will not increase water availability nor will they foster investments in new capacity if no new capacity is needed for a normal hydrological year. In this case high prices may sanction a wealth transfer from consumers to producers without giving effective price signals.

Section 3.3 presented three interesting cases, from Chile, Brazil and Colombia, where long term contracting was introduced partly in order to shield consumers from short term price volatility while giving generators revenue predictability.

Those experiences are sobering in the sense that all of them resulted in high financial risk for generators that would eventually lead them not to fulfill their obligations during high price periods which, in the case of Brazil and Chile, led to a change in risk allocation that reintroduced short term price risks for consumers.

The European approach seems more flexible in comparison. In today's European electricity markets wholesale electricity costs are just a part of electricity costs for consumers, network costs excluded. Other energy related costs, such as capacity costs or subsidies for feed-in renewable generation, are passed through to consumers through their suppliers, who pay the corresponded fixed charges or levees. Suppliers in turn compete for clients and they are free to design retail products that consumers can pick and choose. Retail products are differentiated, some of them offering predicable prices for consumers while others expose consumers to short term price risks. Naturally as energy costs become more fixed cost based this will eventually be passed through to consumers.

One important point, that was basically overlooked by experiences like the ones mentioned from Chile, Brazil and Colombia is that some consumer exposure to short term prices is desirable as it gives them a correct short term economic signal. For instance, if there is excess generation during some hours of the day, consumers should have a price signal that tells them to increase their demand during these hours. This can be achieved if proper wholesale to retail incentive mechanisms are in place, for instance if suppliers act as consumer aggregators. Even a consumer that has chosen a fixed price plan may eventually participate in demand response or in a distributed storage scheme, through which not the bulk of its consumption but only the parts allocated to these demand response or distributed storage programs are actually valued at spot prices.

# 5 Conclusion

Many countries have adopted aggressive goals for decarbonizing their economies that include increasing the share of renewables in the electric sector. As most electricity markets were built for systems where fossil-fuel, variable cost based generators, markets designs will eventually have to evolve in order deal with systems dominated by renewable, fixed cost based generators.

The basic problem in markets where firms do not have substantial variable costs is that short term prices are not able to give consistent signals for long term decisions, leading markets that cannot adjust automatically in the long run.

In a competitive market where all firms have a pure fixed cost based cost structure there would be short term prices. But even countries that plan to have an all renewable electric system will take many years build them. And in the future some renewable generators may have significant variable costs, like green hydrogen power plants. Therefore short term markets are here to stay. They will adapt and not fade away.

Market design challenges for the next decade are related to the trend for fixed cost generation becoming progressively dominant. As this happens, short term market prices will no longer play the role they are supposed to play in text book competitive markets:

i) investments and divestments decisions based only on expected short term market prices may no longer be socially optimal and;

ii) there will no longer be an economic driver making short term prices and production costs converge.

Today's markets already include some features that do not belong to text book competitive markets and that partially address those questions, like capacity contracts and government organized auctions for long term renewable generation. But there are some new challenges in an all renewables system and the final parts of this paper analyses two of them.

1) A system dominated by renewable generation requires new technologies that currently lack a proper market framework, the most notable being storage. Storage will be critical to use excess energy generated when electricity from natural sources exceeds demand and for security of supply when non-controllable generation is very low. The authors argue that an upcoming market framework for storage should take into account that these plants should be dispatched even in situations where marginal costs, and therefore prices, are zero. A market based storage dispatch would not be cost efficient for the system and therefore an alternative framework should be devised where cost minimizing storage dispatch can become a reality.

2) As the generation cost structure becomes more fixed cost centered, consumers will eventually have energy bills with a strong fixed cost component. The authors advocate that this can happen without eliminating short term market price signals, arguing in favor of wholesale to retail schemes that enable even consumers who pay a fixed cost for their energy may, though aggregators, respond to short term prices.

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