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Tesi de màster

Optimal sale bid for a wind producer in Spanish day-ahead market

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Index

Dedicatorias

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Los quiero.

Introduction

Wind power generation has a key role in Spanish electricity system since it is a native source of energy that could help Spain to reduce its dependency on the exterior for the production of electricity.

Apart from the great environmental benefits produced, wind energy reduce considerably spot energy price, reaching to cover 16,6 % of peninsular demand.

Although, wind farms show high investment costs and need an efficient incentive scheme to be financed. If on one hand, Spain has been a leading country in Europe in developing a successful incentive scheme, nowadays tariff deficit and negative economic conjunctures asks for consistent reductions in the support mechanism and demand wind producers to be able to compete into the market with more mature technologies.

The objective of this work is to find an optimal commercial strategy in the production market that would allow wind producer to maximize their daily profit. That can be achieved on one hand, increasing incomes in day-ahead and intraday markets, on the other hand, reducing deviation costs due to error in generation predictions.

We will previously analyze market features and common practices in use and then develop our own sale strategy solving a two-stage linear stochastic optimization problem.

The first stage variable will be the sale bid in the day–ahead market while second stage variables will be the offers to the six sessions of intraday market.

We will implement two models, one incorporating randomness due to errors in generation predictions, the other including also uncertainty in intraday market prices.

The model is implemented using real data from Fersa Renewable Energies, a wind producer leader in Spain.

1. Spanish Electricity Market.

Spanish electricity market is a spot (or pool) market, based on merit order dispatch. It is organized as a sequence of markets:

- The day-ahead market;
- Several intra-day markets that operate close to real time;
- Ancillary services market.

Participation to these markets is not compulsory, as producers and direct consumers are allowed to enter into physical bilateral contracts. Those are incorporated in the production market once the day–ahead market has closed.

The economic management of the electricity market is entrusted to OPERADOR DEL MERCADO IBÉRICO DE ENERGÍA – POLO ESPAÑOL, S.A. (OMEL). It orders the supply and demand bids received in ascending and descending order, respectively and computing the intersection between the industry supply and demand curves (market clearing) determines the dispatch and the equilibrium prices.

Conditionally on being dispatched, the price to be received or paid by market participants is set according to a uniform-price auction.

Namely, irrespectively of their bids, the price they receive (if producers) or pay (if distributors, retailers or eligible consumers) is set equal to the highest accepted supply bid (the so-called System Marginal Price).

Market participants are companies authorized to participate in the electricity market as electricity buyers and sellers. Entities that are authorized to engage in the market are electricity producers, last resort resellers and resellers, direct consumers and companies or consumers resident in other countries that are authorized to participate as resellers. Producers and direct consumers may participate in the market as market participants or sign physical bilateral contracts.

The main processes in the Production Market are the following:

- Most transactions are carried out in the daily market. All available production units must participate in this market as sellers and are not linked to a bilateral contract, as well as non-resident retailers registered as sellers. Buyers on the daily market are last resort resellers, resellers, direct consumers and non- resident retailers registered as buyers. The result of market clearing ensures that maximum interconnection capacity with external electricity systems is not exceeded, considering physical bilateral contracts that affect international interconnections.

- Resolution of technical constraints. Once the daily market session has been held and national physical bilateral bids have been received, the system operator evaluates the technical viability of the operating schedule of the production units in order to guarantee the safety and reliability of supply on the transmission network. If the result of daily market matching and physical bilateral contracts does not respect the maximum exchange capacity between electricity systems or the mandatory security requirements, the technical constraints solution procedure is applied, which consists, firstly, of the modification of purchases or sales from external electricity systems responsible for this excess in interconnection exchanges and, secondly, of the assignation of the power of the production units.
- The intraday market is an adjustment market that is open to production units, last resort resellers, resellers, direct consumers and non-resident retailers engaging as buyers and sellers who are market agents. In order for buyers on the daily market to be able to participate in the intraday market, they must have participated in the corresponding daily market session or must have executed a physical bilateral contract.
- The purpose of ancillary services and deviation management is to ensure that energy is supplied under established conditions of quality, reliability and security and that production and demand are balanced at all times. The system operator incorporates regulating band ancillary services in the viable daily schedule after the daily market sessions have been held. After every intraday market session, the system operator manages any deviations in real time using ancillary services and the deviation management procedure.

1.1. Daily Market.

The purpose of the day-ahead market, as an integral part of electricity power production market, is to handle electricity transactions for the following day through the presentation of electricity sale and purchase bids by market participants.

BID UNITS

Sellers on the electricity power production market are obliged to comply with the Electricity Market Activity Rules by signing the corresponding contract of adherence. Bids made by these sellers are presented to the market operator and will be included in a matching procedure that will affect the daily programming schedule corresponding to the day after the deadline date for the reception of bids for the session, and comprising twenty-four consecutive programming hours (twenty-three or twenty-five periods on days on which the clocks are changed).

All available production units that are not bound by physical bilateral contracts are obliged to present bids for the daily market. self-producers and producers under the special regime are also not obliged to declare surplus power to the market, and may alternatively furnish bids to the market and will continue to be entitled to receive the incentives established for that regime. Buyers on the electrical power market are last resort retailers, resellers, resident or no resident into Iberian Market and direct consumers. Buyers may present bids to purchase electricity on the daily market. However, in order to do so they must be registered and must abide by the Electricity Market Activity Rules. A purchasing unit is deemed to refer to a group of network connection nodes through which the buyer presents bids to purchase electricity.

- Last resort retailers participate in the market to purchase the electricity that they need to supply consumers under the regulated tariff regime.
- Resellers participate in the market to purchase electricity to sell to direct consumers.
- Direct consumers may purchase electricity directly on the organized market, through a reseller by signing a physical bilateral agreement with a producer or by temporarily remaining as consumers under the regulated tariff system.

BIDS PRESENTATION

Sale and purchase bids can be made considering between 1 and 25 energy blocks in each hour, with power and prices offered in each block. In the case of sales, the bid price increases with the block number; in the case of purchases, the bid price decreases with the block number.

Electricity sale bids presented by sellers to the market operator may be simple or incorporate complex conditions in terms of their content. Sellers for each hour and production unit present simple bids, indicating a price and an amount of power. Complex bids are those that incorporate complex sale terms and conditions and those which, in compliance with the simple bid requirements, also include one or some the following technical or economic conditions:

- Indivisibility.
- Load gradients.
- Minimum income.
- Scheduled stop.

The indivisibility condition enables a minimum operating value to be fixed in the first block of each hour. This value may only be divided by the application of the load gradients declared by the same agent, or by applying distribution rules if the price is other than zero.

The load gradient enables the maximum difference between the starting hourly power and final hourly power of the production unit to be established, limiting maximum match able power by matching the previous hour and the following hour, in order to avoid sudden changes in the production units that the latter are unable to follow from a technical standpoint.

The condition of minimum income enables bids to be presented in all hours, provided that the production unit does not participate in the daily matching result if the total production obtained by it in the day does not exceed an income level above an established amount plus a variable remuneration established in euro cents for every matched kWh.

The condition of scheduled stop enables production units that have been withdrawn from the matching process because they fail to comply the stipulated minimum income condition to carry out a scheduled stop for a maximum period of three hours, avoiding stoppages in their schedules from the final hour of the previous day to zero in the first hour of the following day by accepting the first slot of first three hours of their bids as simple bids, the only condition being that energy offered in bids must drop in each hour.

BIDS MATCHING PROCESS

Market operator matches electricity power purchase and sale bids (received before 10 a.m. on each day) by means of the simple or complex matching method, depending on whether simple bids are presented or whether there are bids that incorporate complex conditions. The simple matching method obtains the marginal price independently, as well as the volume of electricity that is accepted for each production and purchase unit for each hour in the schedule. The complex matching method obtains the matching result using the simple matching method, to which the conditions of indivisibility and load gradient are added, thus giving rise to simple conditioned matching. By means of a repeating process, various simple conditioned matches are made until all the matched bid units fulfill the minimum income condition as well as the scheduled stop condition; this solution is the first provisional final solution, obtained by considering an unlimited capacity in international interconnections. This repeating process enables the first definitive final solution to be achieved, which respects maximum international interconnection capacity, considering both the offers made to the daily market and specific physical bilateral contracts that affect the aforementioned interconnections. The price in each hour will be equal to the price of the last block of the sale bid of the last production unit whose acceptance has been required in order to meet the demand that has been matched. The matching result represents the hourly production and demand schedule on the network established by the market operator by matching electricity sale and purchase bids and determines the volume of electricity production required to cover electricity demand in each hour of the same day. The base daily operating schedule is obtained at 11 a.m., once the reports on the execution of all physical bilateral contracts have been obtained, together with information on production under the special regime that has not submitted bids to the market. The base operating schedule will include the following elements:

- The marginal price for each hour in the same hourly schedule.
- Electric power by block that corresponds to each production unit whose sale bid has been matched, and the electric power by blocks that corresponds to each purchase unit whose bid has been matched. The merit order that corresponds to each block of the sale bids of production units that have been totally or partially matched.
- Electric power by block that corresponds to the production unit whose sale bid has not been matched, either totally or partially, together with its merit order.
- Electric power that is programmed by available production units exempted from the obligation to present bids, such as production units subject to the special regime, as well as power executed daily under physical bilateral contracts.

Once the daily market process has concluded and the base daily operating schedule has been obtained, system operator will obtain the viable daily schedule, agreeing the withdrawal of blocks of sale or purchase bids that affect international interconnections if maximum international interconnection capacity is exceeded, and the withdrawal and/or incorporation in the base operating schedule of electricity sale bids in order to resolve the technical constraints on the Spanish and Portuguese electricity system (before 14:00 hours), without prejudice to the assignation of ancillary services.

1.2. Intraday Market

The purpose of the intraday market, which is regulated by Article 15 of Royal Decree 2019/1997 as an integral part of the electricity power market, is to respond, through the presentation of electricity power sale and purchase bids by market agents, to adjustments made to the Final Viable Daily Schedule.

Market participants may adjust their positions in either direction (e.g. producers may submit purchase bids if they expect to be short, and distributors, retailers and eligible consumers may submit sale bids if they anticipate to be long).

The intraday market is currently structured into six sessions with the following hourly distribution per session:

	SESSION 1º	SESSION 2ª	SESSION 3ª	SESSION 4ª	SESSION 5ª	SESSION 6ª
Session Opening	16:00	21:00	01:00	04:00	08:00	12:00
Session Closing	17:45	21:45	01:45	04:45	08:45	12:45
Matching Results	18:30	22:30	02:30	05:30	09:30	13:30
Reception of Breakdowns	19:00	23:00	02:45	05:45	09:45	13:45
Constraints Analysis	19:10	23:10	03:10	06:10	10:10	14:10
Adjustments for Constraints Publication PHF	19:20	23:20	03:20	06:20	10:20	14:20
Schedule Horizon (Hourly periods)	28 hours (21-24)	24 hours (1-24)	20 hours (5-24)	17 hours (8-24)	13 hours (12-24)	9 hours (16-24)

The schedules are the ones established in the Electricity Market Activity Rules. Those that appear in the attached table are the possible schedules limit. Numerous sale and/or purchase bids may be presented for each production or purchasing unit.

SALE BIDS

All agents authorized to present electricity sale bids on the daily market and those agents authorized to present purchase bids on the daily market and who have participated in the corresponding daily market session in which the intraday market session is opened, or who have executed a physical bilateral contract, may participate in the intraday market. The aforementioned agents authorized to present purchase bids on the daily market may only participate in the intraday market for the hourly periods corresponding to those included in the daily market session in which they have participated.

Electricity sale bids presented by sellers to the market operator in the intraday market may be simple or incorporate complex conditions according to their content.

Simple bids are electricity sale bids consisting of 1 to 5 blocks that the sellers present for each hourly period and production or purchase unit that they own. These simple bids indicate a price and amount of power; the price increases in each block.

Sale bids that include complex conditions comply with the stipulated conditions governing simple bids, and may include all, several or one of the following complex conditions:

- Load gradient.
- Minimum income.
- Complete acceptance in the matching process of the first block of the sale bid.
- Complete acceptance in each hour in the matching period of the first block of the sale bid.
- Minimum number of consecutive hours of complete acceptance of the first block of the sale bid.
- Maximum matched power.

The load gradient and minimum income conditions are the same as those described for the daily market.

The condition of complete acceptance in the matching process of the first block of the sale bid establishes a profile for all the hours of the intraday market, which may only be matched if this is matched in the first block of all the hours. This enables the production or purchase unit schedules to be adjusted to a new profile; if this is not possible in one part, the previous schedule can be left without modifying any of the hours individually. This option is used when the programming of certain hours is only possible if this can also be done in others, such as in order to bring forward the start-up or stoppage process, avoid boiler bottlenecks, etc.

The condition of complete acceptance in each hour in the matching process of the first block of the sale bid means that only the first block will be programmed in a specific hour if it is not matched completely, and all the blocks in that hour will be withdrawn and not the bid presented for the other hours. This option is useful for programming groups that produce (technical minimum) or consume (pumping consumption), a minimum value or nothing. It may also be useful for consumers to notify a similar situation.

The condition of a minimum number of consecutive hours with complete acceptance of the first block of the bid may be applied when the production or purchase unit must produce or stop consuming consecutively at least a number of hours. The same condition would apply to consumers who, for example, are unable to operate a plant for a number of hours below the number specified in the bid.

The condition of maximum matched power enables bidding units with limited available power to bid in all hours, although limiting the matched value to an overall maximum power.

This condition is necessary due to the volatility of prices in the intraday market between hours, which make it impossible to determine the hours in which the production or purchasing units may be matched; however this condition has a limit on the power that they can sell, such as in the case of pumping generating units.

The sale bids for each intraday market session must be such that the final schedule resulting from the complete acceptance of the bid plus the previous schedule of the production or purchasing unit respects the limitations declared by the system operator for the scheduling horizon, or if it does not comply with these prior to the presentation of the bid, it must be close to complying with them.

PURCHASE BIDS

All agents authorized to present electricity purchase bids on the daily market and those agents authorized to present sale bids on the daily market and who have participated in the corresponding daily market session in which the intraday market session is opened, or who have executed a physical bilateral contract, may participate in the intraday market. The aforementioned agents authorized to present purchase bids on the daily market may only participate in the intraday market for the hourly periods corresponding to those included in the daily market session in which they have participated.

Electricity purchase bids may be simple or incorporate complex conditions. These are the same as those applicable to sale bids, except in the case of the maximum payment condition, which is equivalent to that of minimum income applied to power purchases, which are not matched if the cost is greater than the fixed value expressed in Euros, plus the variable cost expressed in pesetas or euro cents for each kWh matched.

The purchase bids for each intraday market session must be such that the final schedule resulting from the complete acceptance of the bid plus the previous schedule of the production unit respects the limitations declared by the system operator for the scheduling horizon; if it does not comply with these prior to the presentation of thebid, it must be close to complying with them.

Matching process and results on equilibrium market prices will be the same as in the day-ahead market, ensuring demand and offer to comply with system's restrictions and hourly prices determined by economic order dispatch.

2. Renewable Energy Regulation

Directive 2009/28/EC of the European Parliament and of the Council of 23 April 2009 on the promotion of the use of energy from renewable sources establishes the general targets of 20% share of energy from renewable sources in gross final consumption of energy in the European Union (EU) and a 10% target for energy from renewable sources to be achieved by all Member State in energy consumption in the transportation sector by 2020.

To achieve that, it sets 2020 targets for each Member State and a minimum indicative trajectory leading up to that year. In Spain, the target means that renewable sources must account for at least 20% of final energy consumption by 2020 - the same as the EU average - together with a contribution of 10% from renewable sources in the field of transport by that year.

The Directive calls on every Member State to draw up and notify a National Renewable Energy Action Plan (NREAP) for the period 2011-2020 to the European Commission (EC) by 30 June 2010 with a view to complying with the binding targets laid down in the Directive. As the Directive indicates, that NREAP must conform to the national action plan template adopted by the European Commission via the 30 June 2009 Commission Decision establishing a template for National Renewable Energy Action Plans under Directive 2009/28/EC of the European Parliament and of the Council.

For its part, Royal Decree 661/2007 of 25 May 2007 regulating activities related to electrical energy production under special regimes provides for the drafting of a Renewable Energy Plan for implementation during the period 2011-2020 (REP 2011-2020).

Later on, national legislation will have to incorporate Directive 2009/72/EC on common rules for the creation of an internal electricity market for European Union.

SUMMARY OF NATIONAL RENEWABLE ENERGY POLICY

European and Spanish energy policy

Oil prices and the geographical distribution of energy reserves have shaped the energy options of developed countries for over three decades. More recently, environmental concerns, the intense growth of emerging countries and the ensuing inflationary effect on primary energy sources, along with the liberalization of Europe's energy sector, have been characterizing the new frame of reference for devising energy policy.

Within the scope of the European Union, the need to make coordinated progress in the liberalization of markets, the assurance of supply, the development of interconnection infrastructures and the reduction of polluting emissions along with other issues has become increasingly evident.

Energy policy in Spain has progressed along these lines in a harmonized fashion with other European countries but, at the same time, it presents a specific response to the main challenges that have traditionally characterized the Spanish energy sector and which can be summarized as follows:

- Higher energy consumption per unit of gross domestic product. Spain consumes more energy than the average of European countries to produce the same unit of gross domestic product, even in comparison with those that have a similar industrial and productive structure and level of economic development. This situation is due to a variety of factors and is not an irreversible but rather the effect of the accumulation of energy- intensive economic growth patterns.

- High degree of energy dependency. The scant presence of primary fossil fuel deposits has historically determined a high rate of energy dependence for Spain. This greater dependence means added risk for production processes such as those related to ensuring energy supply or the volatility of international market prices.

- High levels of greenhouse gas emissions, mostly due to strong growth in electricity generation and the demand for transport over the last several decades.

In order to respond to these challenges, energy policy in Spain has developed around three axes: security of supply, enhancement of the competitiveness of the economy and guarantee of sustainable economic, social and environmental development.

In Spain, energy policy has prioritized liberalization and the fostering of market transparency, the development of energy infrastructures and the promotion of renewable energies, savings and energy efficiency.

Market liberalization and transparency through the establishment of mechanisms to guarantee that users take their decisions with the greatest amount of available information marks a step towards efficiency in decision-making by agents.

The development of renewable energies is a priority for Spanish energy policy. Renewable energies have a number of positive effects on society at large including the sustainability of their sources, reduction in polluting emissions, technological change, the opportunity to advance towards more distributed forms of energy, reduction of energy dependence and the trade balance deficit and increase in rural employment and development.

Naturally, these advantages imply greater economic hardship, which tends to diminish over time thanks to shifts in technology over the span of the learning curves. Moreover, in some cases renewable technologies raise relevant issues regarding their predictability and manageability. Nevertheless, these last difficulties can be overcome thanks to headway made in system management, the use of storage techniques such as pumping or the development of renewable facilities with storage capabilities.

In general, the analyses conducted on the Spanish system indicate that the benefits of renewable energies are both high and stable. As already mentioned higher costs are limited and tend to decrease over time. Comparisons show that overall future benefits exceed present costs by a wide margin and justify the regulatory framework supporting renewable energies.

In Spain, the regulatory framework governing electricity generation using renewable energies revolves around a mechanism known as the feed-in tariff whose operation is based on guaranteeing a price higher than that existing in the wholesale market for the technology employed. This cost increment is financed by electricity tariffs themselves. This is not a classical system of direct subsidies paid to producers. Under this scheme the cost is shared between producers of conventional energies and consumers given that prioritizing the entry of renewable energy into the electricity system will bring about a price decrease in the electrical energy production market. Consumers are only financing the part of renewable production not covered by this effect.

As the European Commission has pointed out, the results of the Spanish model are a success story in the design of policies to promote renewables. The main result is the volume reached by renewable electrical energy, which has attained a consolidated structural position of the first importance.

It is fair to say that the 2005-2010 Renewable Energy Plan has been an undisputed success in that as it has not only transformed Spain's energy model as planned, but has also allowed for the development of an industry which has positioned itself as a leader in many segments of the value chain at international level.

However, the success of the policy to foster renewable energies over the coming years should be measured in terms of achievement of the established development objectives, and especially in terms of attaining these in a way compatible with the technical, economic and environmental sustainability of the energy system as a whole while fostering competition between technologies and their competitiveness with traditional sources, an aim which is ultimately the surest guarantee that a technology will remain stable over time as part of the energy mix. Specific indicators are defined to monitor all of this.

3. Wind energy generation.

Wind energy is the most mature and developed renewable energy. It generates electricity by way of the strength of the wind using the kinetic energy produced by air currents. It is a clean, inexhaustible source of energy that reduces the emission of greenhouse gases and preserves the environment.

Wind energy has been used since antiquity to move sail-powered boats or drive windmill machinery by moving their blades. Since the early 20th century energy has been produced by way of wind generators.

Wind energy moves a propeller and, by way of a mechanical system, it turns the rotor of a generator that produces electrical energy. Wind generators are usually grouped into facilities called wind farms with a view to achieving a better use of the energy that reduces their environmental impact. The machines have a working life of approximately twenty years.

Spain is an energy island that is highly dependent on the exterior (81% of the primary energy consumed is imported and derives from fossil fuels) and it needs more security as regards the supply of energy.

Wind energy is a native source of electrical generation, the third in the country after gas and nuclear It avoided imports of fossil fuels (which are a serious burden on the Spanish balance of trade and make economic reactivation difficult) for the sum of 1,541 million Euros in 2009 and in 2010, it covered 16.6% of the electrical demand in the country. Spain is the fourth country in the world in terms of installed wind power after the US, Germany and China.

Hence, the wind sector is key to comply with the European energy consumption objectives using renewable sources in 2020.

Moreover, wind energy is a source of wealth and employment since:

- Wind energy sector employs over 35,000 people
- It is the engine of the rural communities in which it is located (job creation, purchases from local suppliers, demand for services)
- Spain is the fourth country in the world in terms of wind energy patents: in 2009 the sector invested 156 million Euros in R&D

- Wind energy increasingly contributes to GDP (3,207 million Euros in 2009) and to exports (2,100 million Euros)

From an economical point of view:

- Wind energy contribute to lower equilibrium market price (-3.4 Euros per MWh registered in 2009) offering at price zero and dislodging more expensive combustion technologies;
- Producers receive a total income that is one of the lowest in the European Union (around 79 Euros MW/h, compared with 92 Euros in Germany, 86 in France and 152 in Italy).
- Wind energy is the most competitive technology included under the special regime (which does not only include renewables, but also cogeneration)
- Wind energy costs every average Spanish home 1.3 Euros a month and saves each industrial consumer 160,000 Euros on average per year

The increasing importance of preventing climate change makes the contribution of wind energy even more remarkable if we think that it does not contaminate, is inexhaustible and slows down the exhausting of fossil fuels. It is a leading technology at avoiding CO2 emissions (20.6 million tonnes in 2009, entailing a saving of 270 million Euros)

Every kWh produced with wind energy has 21 times less environmental impact than that produced by oil, 10 times less than that of nuclear energy and 5 times less than gas.

3.1. WIND SECTOR OVERLOOK

In 2010 Spanish wind sector proved to be able to comply with the goals established in the Renewable Energy Plan for 2005-2010.

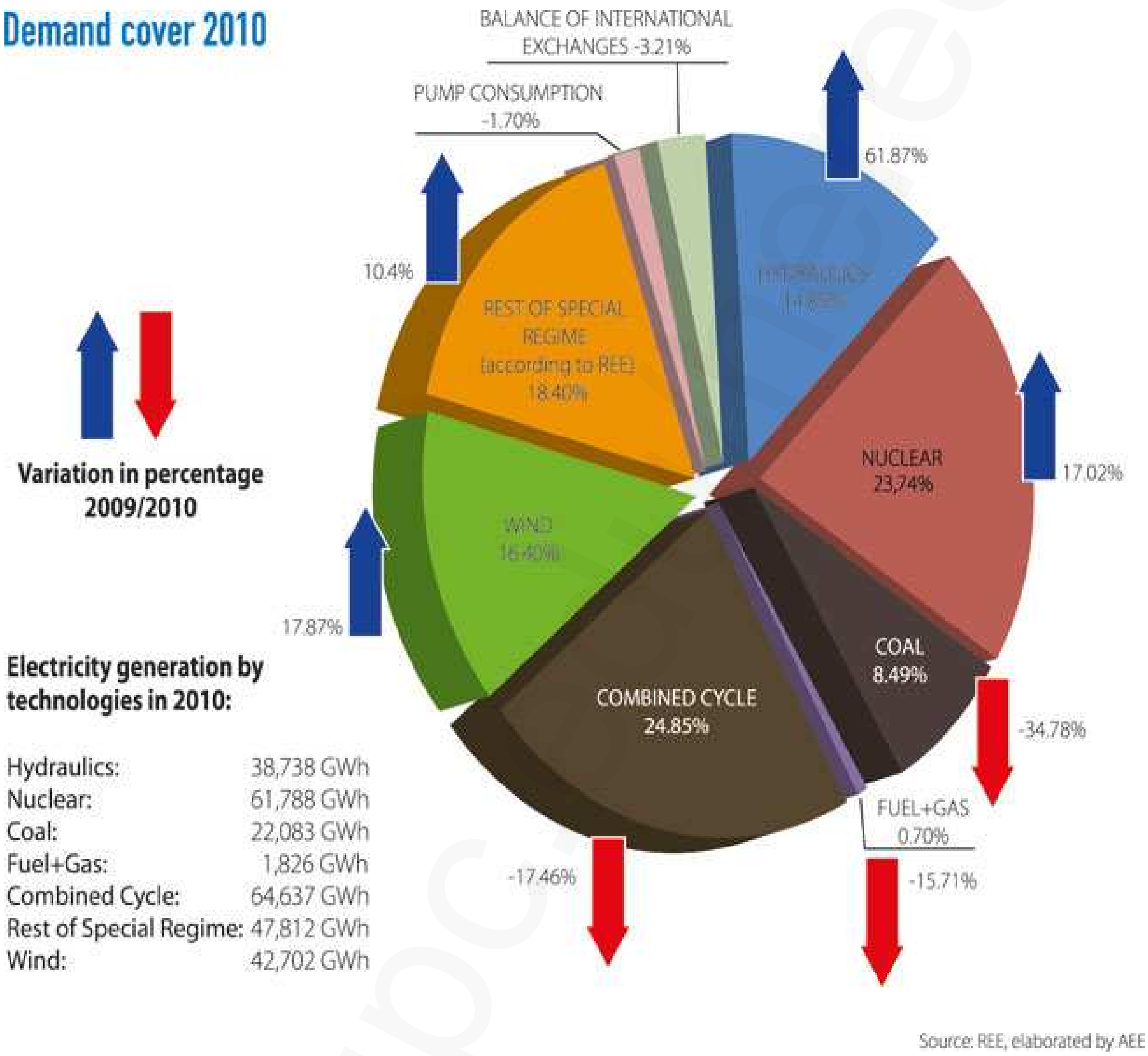
Last year 1516 MW where installed, for a total installed capacity at the end of the year of 20676 MW. It was the second technology in installing more MW in the system, after cogeneration.

In the following graph we show the evolution in the annual and total capacity installed since 1998.

Even if it is clear that wind installed capacity continuously increase since 1998, 2010 increase is one of the lowest registered in the last ten years and suggests a probable deceleration of the sector due to uncertainty in the future legislation. We will treat this topic in detail in the next chapter.

Last year wind energy production amounted to 42,702 GWh, 6 GWh more than previous year. That corresponds to the 72% of the energy produced by renewable sources.

It covered the 16.6% of peninsular electricity demand, affirming itself as the third technology contributing to the system after cogeneration (24.85%) and nuclear power (23.74%).



Maximum historical production was reached in the first trimester of 2010 (13 GWh) when, on average, wind energy covered the 19.4% of electricity demand. In the same period, plant factor was much greater than the average of the last years, registering a maximum of 36% in February.

3.2. ECONOMIC REGIME FOR WIND ENERGY PRODUCERS

Participation of wind energy in the electricity market has been the principal element distinguishing Spanish model from other European realities.

Spanish regulatory framework, defining market rules and incentives for renewable energies, has been evolving demanding increasing competitive performances to wind producers.

The incentive system first defined in RD 436/2004 provided wind energy producers that started operation before 1 January 2008 two options to sell energy:

- Participate to the spot market, receiving the clearing price plus a fixed subsidy (of approximately 39/MWh)
- Receive a regulated tariff (approximately 70/MWh),

during the entire lifetime of the wind farm (20 years).

So, companies could choose either to face the risk of market price fluctuations or opt for a risk adverse strategy and receive a fixed income. Increasing volatility in market price caused in changing in demand and generation mix, produced a high risk of low minimum income for those wind farms that opted to participate to the market.

Project financing requiring a granted minimum income for new projects, pushed the regulator (whose concern was to stimulate investments in the sector and participation to the market) to modify the initial regulation and establish a more efficient incentive system through RD 661/2007. The new scheme grants a minimum and a maximum achievable income participating into the market with the inventive proportional to market price level.

Wind producers can decide yearly if receive a fix tariff or spot price plus a subsidy varying according to hourly market price, regulated floor and cap values.

Subsidy is calculating as showed below:

- If (Spot Price + Reference Subsidy< Floor)→ Subsidy= Floor – Spot Price
- If (Floor<Spot Price + Reference Subsidy<Cap)→ Subsidy= Reference Subsidy
- If (Cap-Reference Subsidy< Spot Price < Cap)→Subsidy=Cap- Spot

- If (Spot Price >Cap)→Subsidy=0

The values of regulated tariff, floor, cap and reference subsidy are update yearly according to IPC value discounted by 0.25 % up to 2013, 0.5% onwards. Value for 2011 are:

Regulated Tariff: 79.084 €/MWh

Reference subsidy: 20.142 €/MWh

Floor: 76.975 €/MWh

Cap 91,737 €/MWh

Due to RD1614/2010 approved in December 2010, reference value for subsidy has been reduced by 35% compared to 2010 until 31 December 2012, re-establishing the update value according to RD661/2007 in 2013.

Wind farms operating in RD436/2004 will enter into RD661/2007 system from 1 January 2013.

During 2010 a strong debate on regulation for new installations was opened, with diverging opinions on the role of wind energy development in Spanish market.

On one hand, the government underlines the necessity to reduce subsidy deficit (that is having important repercussions on state balance) cutting subsidization and demanding competitive performances to wind sector operators, on the other hand wind energy companies reject the possibility to perform as other technologies in the market since investment costs in the sector are still very high.

In this unstable regulatory framework and expecting a lower government commitment in support wind energy, it is fundamental for wind energy producer to develop competitive strategies to participate to the market.

This translates in an extensive use of prediction models, acknowledgment of market mechanism and looking fort procedures to optimize profits and reduce deviations in final programming.

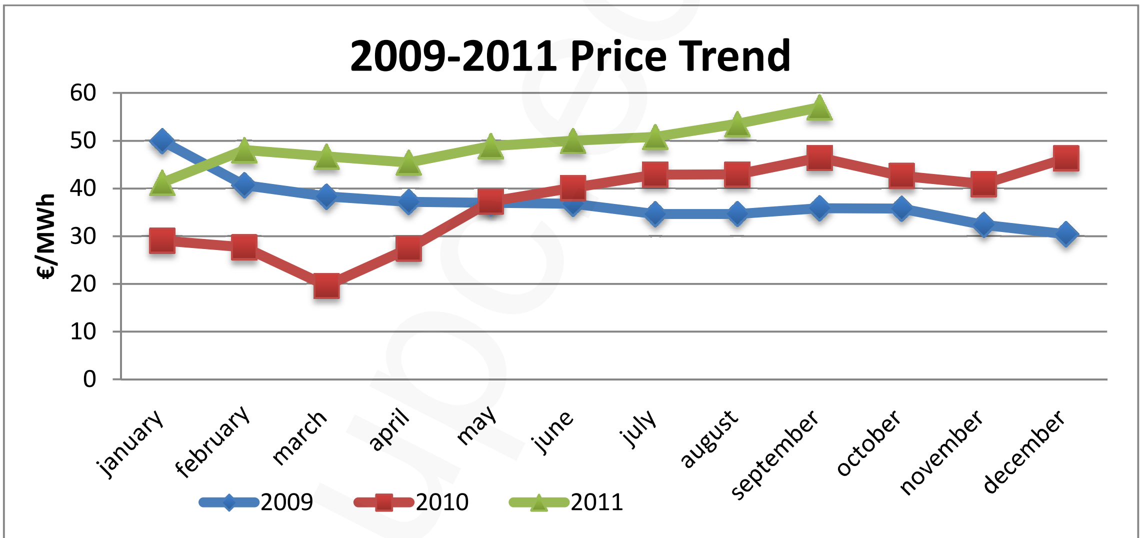
4. Transactions in the Production Market: detected sales strategies.

In this chapter we will analyse data on clearing prices and energy volumes negotiated in the day-ahead and intraday markets to understand common sales strategies adopted by wind energy producers and market participants in general.

4.1. State of the market: wind producer perspective.

From a macroeconomic point of view, financial crisis affecting the major European economies caused considerable volatility in utilities' markets during the last 2 years. Lower industrial demand produced a decrease in market prices during 2009 and 2010 while petroleum reserves' shortfall due to conflicts in Africa pushed prices up during the last six months.

In the following graph we show monthly average spot prices' trend in Spanish electricity market from January 2009 until September 2011.



Prices started decreasing in February 2009 and reached the minimum in March 2010 (approximately 19€/MWh). The first quarter of 2010 was mainly characterized by low industrial demand and high wind production. Actually from December 2009 spot market registered numerous zeros in price curve, meaning that wind energy was covering alone (or with other renewable sources) electricity demand in many hours. That generated great surprise among market participants and indisputable benefits for energy buyers. Unfortunately wind operators that did not choose regulated tariff regime were damaged by their own efficient performances.

As a consequence, many wind producers that previously opted for participation into the market, switched to regulated tariff not to register increasing losses, while many installations under RD436/2004 that did not have the same possibility, had to face market risk and look for some profitable sale strategy.

In the same way, cut in subsidization and uncertainty in future regulatory framework, ask for high efficiency in market performances of wind producers.

Room for bettering profits can mainly be seen in three areas:

- Improvement in prediction models
- Acknowledgment of market mechanism
- Reduction in deviation penalizations.

4.1.1. Improvement in prediction models

Being able to efficiently predict generation is important to determine not only daily programming but to manage companies' cash flows. Moreover, wind farms have different productivity characteristics depending on the area where they are installed: some show peak production during night hours others during the day. So, average real price received can vary greatly among installations and in different time of the year. Spanish wind farms show worse performances during summer time.

During the last years many companies have invested in evolved prediction software and contracted external companies specialized in meteorological studies to be continuously updated on wind conditions, turbines performance and production levels.

More precise data on load factor of their own installations allowed wind energy companies to open to a type of derivative contracts called "base load contracts". Those are future bilateral contracts, signed with market agents that establish a fix price for a base load the producer wishes to grant. The price depends on future market quotations (OMIP) for the period committed while the base load is chosen by the producer according to its own productivity and being aware that:

- If hourly production is less than the base load, he will pay this difference at real market price

- If hourly production is greater than the base load, he will get paid the excess production at real market price.

Awareness on load factor and wind farm performance are indispensable to limit the risk of shortfall in generation.

4.1.2. Acknowledgment of market mechanism

Market mechanism allows participants to close transactions not only in the day-ahead market, but also into six sessions of intraday market, to adjust final programming.

Wind producers, offering at price zero and having priority in the dispatch, are not concerned on offer acceptance and they can only opt for simple quantity offers. In many cases they do not use intraday markets unless the prediction received after the day-ahead market closing considerably differs from the one used to formulate its sale bid.

Market agents, that manage many generation units of different sources, present an aggregate offer to the market and have developed some business strategy to exploit the economic potential of their portfolio. They adjust customers' offers to have an additional income. In the case of renewable plants, they normally increase sales bids because they are aware they will be accepted in any case.

Acknowledgment of market mechanism will allow wind producers to better exploit their resources and design some business strategy to increase their daily benefits.

4.1.3. Reduction in penalizations for deviations.

Penalizations for deviations are closely related to prediction models improvement since the "size" of the penalizations depends on the difference between final programming and real generation.

Market agents, managing different power plants can "compensate" deviations among production units and grant a reduction in the final cost per MWh incurred. Again, producers are paying a portfolio effect, participating to the market through the market agent but what can they do to better their performance?

Penalization strictly depends on relationship between aggregate demand and offer:

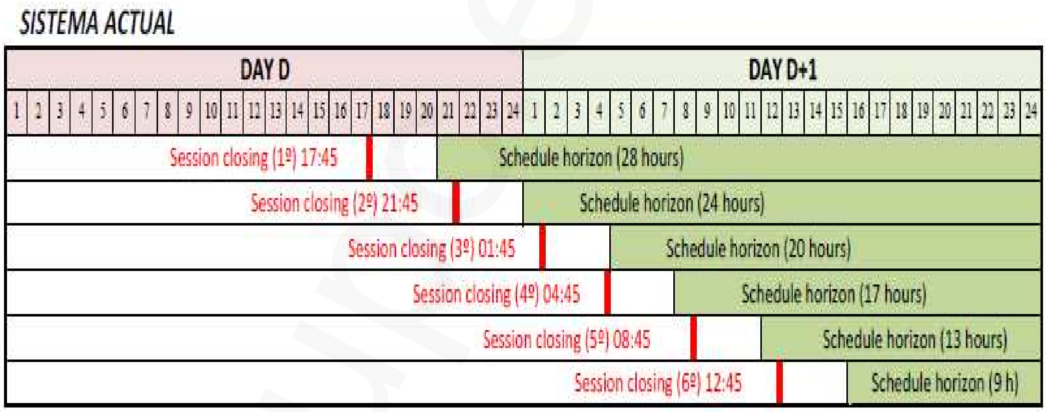
- If real generation is greater than final programming then penalization is paid only if the demand is lower than the offer (excess on the offer side);
- If real generation is lower than final programming then penalization is paid only if the demand is greater than the offer (excess on the demand side).

This simply market rule tells us that if we can predict relationship between energy demand and offer we will not pay for deviations adjusting our final programming according to that.

In the last years, low demand level and excess installed capacity in the Spanish system kept the probability of excess on the demand side at negligible levels so that it is recommendable to declare a final programming greater than expected generation.

4.1.3. Characteristics of the markets

As previously seen, the majority of transactions on the production market are held in the day-ahead market that closes at 10 a.m. of day D-1, while the six sessions of intraday markets are conducted according to the schedule showed in the table below.

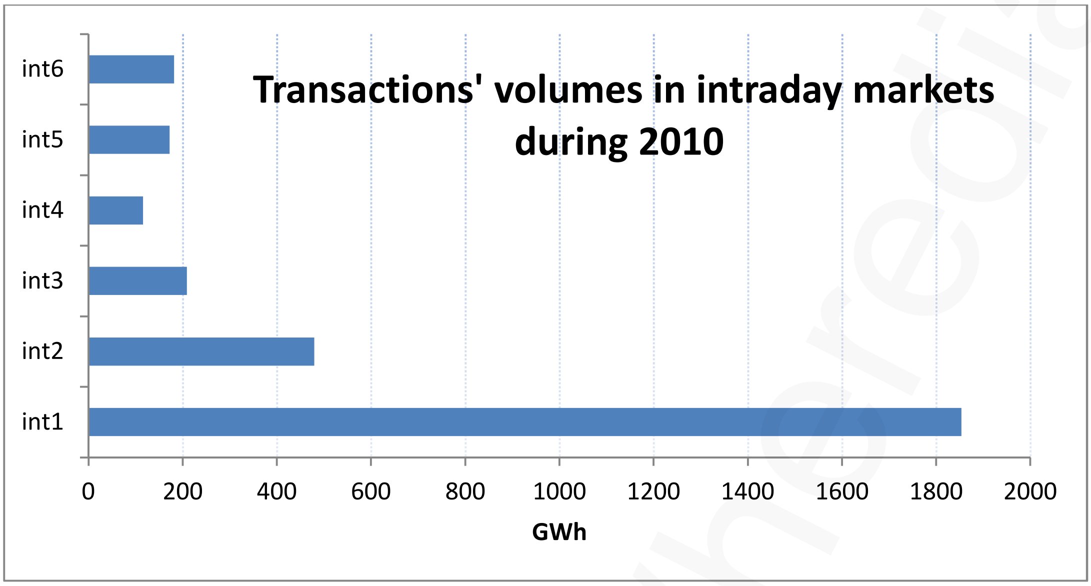


Source: REE web page

Schedule horizon decreases as far as we get close to real generation time.

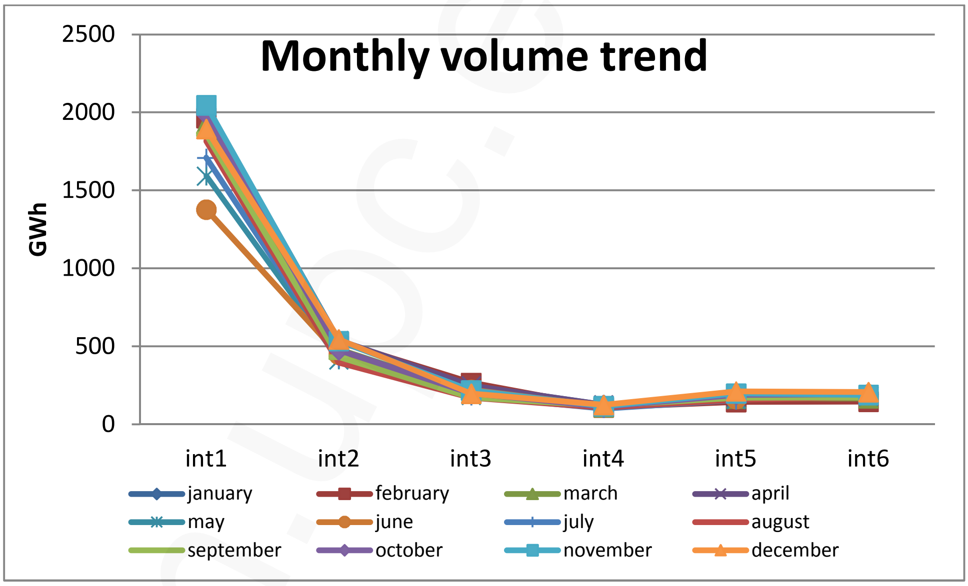
Energy transacted in intraday market represents approximately 18% of that exchanged in the day-ahead markets.

Energy volumes transacted in the six sessions of intraday markets in 2010 are shown in the following graph.



The largest number of transactions was held in the first session while the lowest was held in the fourth session.

This "transactions' volume order" is confirmed on a monthly base as showed in the following graph:



The difference mainly depends on:

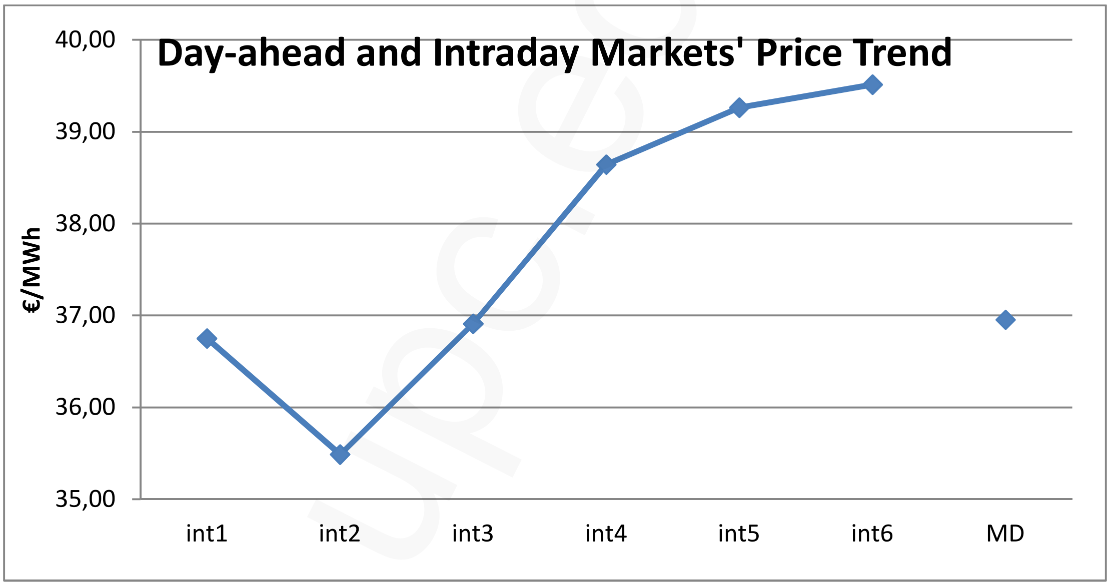
- Different size of market windows;
- Time schedule to present offers;
- Difference in price levels;
- Risk adverse profile of market participant.

Trivially the number of hours adjustable in intraday market one and two is greater than in the next four sessions: that implies an increasing difference in volume transacted. We would expect volumes to be proportional to market windows size but they are not.

Sessions 2, 3 and 4 close during the night. Unless the company dispose of an automatic system to send bids to the market, operations have to be registered manually with an additional cost of paying someone to enter the market agent platform to adjust them during the night.

Moreover, the majority of companies wait until last market sessions to adjust their final programming to the best prediction received.

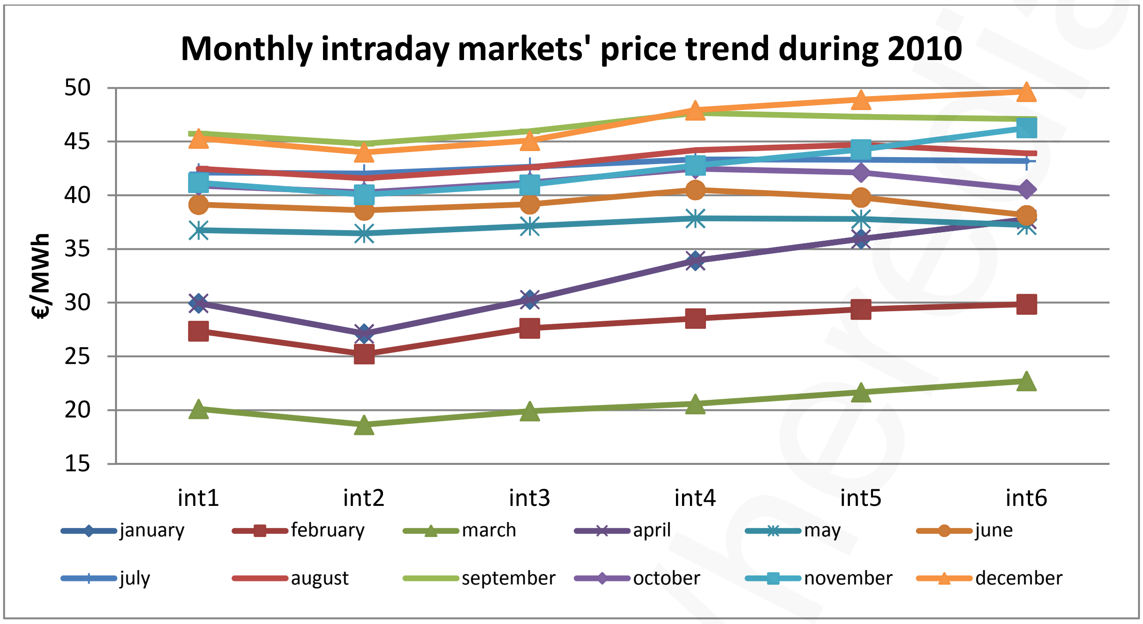
Another reason of difference in volumes relies on price levels in the different markets. In the following graph, relationship between average exchange prices in day-ahead and intraday markets is shown for 2010.



Clearing prices in the first three sessions of intraday markets are lower than day-ahead spot price while average prices of the last sessions are much greater.

It will be profitable to sell energy in the daily market to buy the deficit quantity in one of the first session of intraday markets (especially the second one) and sell exceeding quantity in the last sessions.

This price trend is confirmed on a monthly basis as showed below.



We can state that in 2010, average prices of the first three sessions of intraday markets were lower than the ones of the last three sessions. That suggests a simple strategy that is "buy when is cheap and sell when is expensive".

4.2. DETECTED STRATEGIES FOR A WIND PRODUCER

Energy producers cannot directly participate to the production market unless they are registered as market agents. Since there are companies specialized in manage market transactions that offer additional benefits due to portfolio synergies, the majority of producers contract one of them to handle its commercial operations into the system.

Additionally, in order to continuously receive production estimates, wind producers need to contract a company specialized in wind studies and generation predictions. The information is update during the all 24 hours of each day and has the following structure:

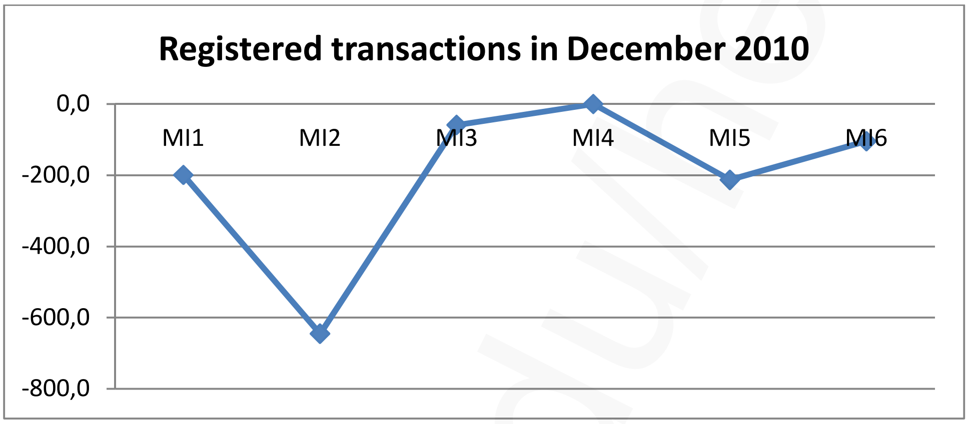
Wind farm	yyyy-mm-dd	hh:mm	cat(kW)	p10(kW)	p90(kW)	disp(/1000)	evac(/1000)
******	*	0:00	20168	3776	32418	1000	1000
******	*	1:00	23171	5053	36828	1000	1000
******	*	2:00	24279	4111	36310	1000	1000
******	*	3:00	24639	3099	34539	1000	1000
******	*	4:00	24378	2712	32219	1000	1000
******	*	5:00	23655	5647	31042	1000	1000
******	*	6:00	22711	8944	30063	1000	1000
******	*	7:00	21884	11789	29406	1000	1000
******	*	8:00	22023	11540	29442	1000	1000
******	*	9:00	22219	10498	29619	1000	1000
******	*	10:00	22061	8926	29594	1000	1000
******	*	11:00	20675	8039	28206	1000	1000
******	*	12:00	18927	6992	26947	1000	1000
******	*	13:00	17106	5857	26293	1000	1000
******	*	14:00	15664	4095	28688	1000	1000
******	*	15:00	14372	2397	31137	1000	1000
******	*	16:00	13213	914	32578	1000	1000
******	*	17:00	12160	237	29572	1000	1000
******	*	18:00	11296	0	25549	1000	1000
******	*	19:00	10805	0	21528	1000	1000
******	*	20:00	11169	479	19743	1000	1000
******	*	21:00	11827	1116	18765	1000	1000
******	*	22:00	12565	1763	18594	1000	1000
******	*	23:00	13210	2174	19412	1000	1000

The first three columns specify respectively to which wind farm the prediction refers to, generation day and time. **Cat** is the actual prediction expressed in kW, **p10** and **p90** are the percentiles 10 and 90 of the distribution of the prediction. **Disp** indicates the availability of the wind farms (expected capacity available for the next day), while **evac** refers to the availability of the evacuation structure.

The 7.30 a.m. prediction is automatically registered in online platform of the market agent that is the only tool usable to send sales bid and adjust final programming.

Some producers have also decided to sign contracts with "intermediary companies" (some sort of consultants) that manage their business strategies granting an extra daily benefit and getting paid a percentage of the same.

Their strategic behavior is apparently very simple, as shown in the following graph, where monthly average transaction volumes per market session in December 2010 are reported. Data are representative for all months of the year.



Strategy basically consists in:

- Not to participate in intraday market 4 (this suggest no automatic tool is used to send bids to the market);
- Sale in the day-ahead market a greater quantity than the prediction received (irrespective of some efficiency criteria);
- Buy in intraday 1 and 2 the missing quantities;
- Eventually adjust for changes in the prediction in the last sessions of intraday markets;
- Never adjust for final programming lower than expected generation (no positive deviation).

It is mainly based on price level differences previously analyzed, with maximum quantities offered generally fixed at 80% of total installed capacity (that is not surprising, since average volatility in wind production is estimated to be approximately 20%).

Going through the details, it is detectable that percentile ninety of the prediction distribution is used as reference maximum value for sale bids in the day-ahead market.

Moreover, market participant show a risk adverse profile: getting close to real generation horizon, limitations imposed by the system operator for security reasons becomes stricter and probability of energy offers complying with them becomes lower. So they prefer to adjust their bids as soon as possible participating to previous sessions of the intraday market.

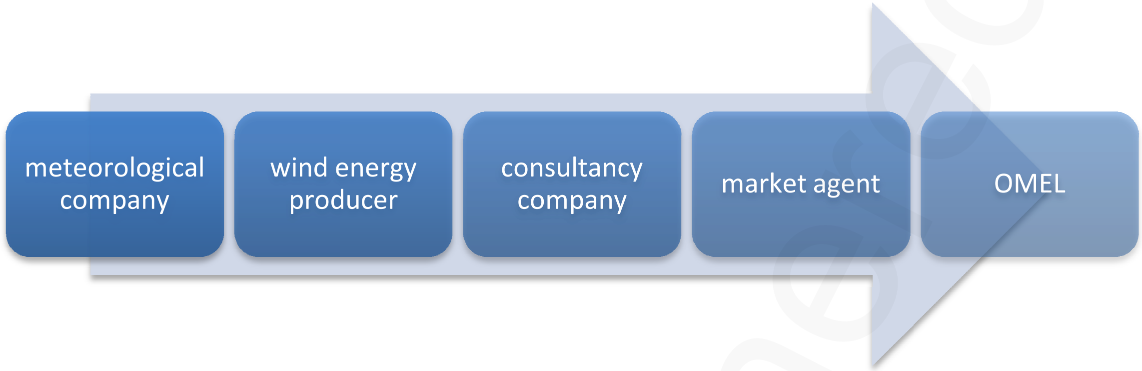
Final programming and market bids are registered daily on the electronic platform of the market agent that has the outlook presented below.

************* - **ACTUACIÓN MERCADO U. PROGRAMACIÓN EPEDRE**

Fecha de Sesión:	04/10/2010

	VARIACIÓN DE ENERGIA POR HORA (MWh) DEFINIDA POR SESIÓN										ENERGIA FINAL
HORA	MD	REST.	MI1	MI2	MI3	MI4	MI5	MI6	MI1'	HORA	(MWh)
H1	21,0		-5,4	-1,9						H1	13,7
H2	20,9		-5,3	-2,2						H2	13,4
H3	21,1		-5,5	-2,1						H3	13,5
H4	20,9		-5,4	-2,1						H4	13,4
H5	21,0		-6,3	-3,2	-1,0					H5	10,5
H6	18,8		-5,0	-3,2						H6	10,6
H7	17,8		-5,2	-4,3	-2,3					H7	6,0
H8	17,7		-6,7	-4,7	-2,8					H8	3,5
H9	14,0		-4,5	-5,2	-2,3					H9	2,0
H10	13,2		-4,8	-4,4	-2,5					H10	1,5
H11	12,6		-5,2	-4,1	-2,2					H11	1,1
H12	12,3		-4,7	-4,0	-2,0					H12	1,6
H13	12,6		-5,3	-3,7	-2,1					H13	1,5
H14	14,3		-6,5	-4,2	-1,6					H14	2,0
H15	14,2		-6,3	-4,0	-1,7					H15	2,2
H16	15,4		-6,7	-4,0	-1,4					H16	3,3
H17	15,6		-6,0	-2,2	-1,8					H17	5,6
H18	16,6		-6,2	-3,1	-1,0					H18	6,3
H19	16,7		-6,1	-3,4	-0,8					H19	6,4
H20	15,8		-6,6	-3,5	-0,4					H20	5,3
H21	14,3		-5,3	-3,8	-1,8					H21	3,4
H22	14,2		-5,9	-4,1	-2,0					H22	2,2
H23	14,2		-5,9	-4,6	-1,7					H23	2,0
H24	14,5		-5,9	-4,5	-2,1					H24	2,0
H25										H25	

In the following charter we resume the steps a wind producer is currently following to formulate its sale bid and final programming, before market operator receives them.



Formulating its own market strategy, a wind producer could avoid at least the "consultancy company" step, directly communicating with its market agent and avoiding a third party to receive information on its generation performance.

5. From an economical to a mathematical point of view

As explained in chapter one, in order to participate to the daily market of day D, market participants have to send hourly generation bids for their power plants before 10.00 a.m. of the day D-1.

The selling strategies of wind power producers mainly depend on the most recent estimates on generation available before day-ahead market closes. They can both declare their units unavailable or formulate an offer according to generation predictions or some commercial strategies.

The simplest and most common way to operate is relying on the last prediction useful for the day-ahead market (that is automatically registered on market agent platform) using it as sale bid and then adjust the final programming participating in the intraday markets sessions if some considerable error in the prediction is detected.

Generation estimates, constructed internally or by a third party and updated all day long, are the results of meteorological forecasts and, even if sophisticated software have been developed to improve prediction models, they still show a significant variability (between 20 and 30%).

When energy producers decide which energy quantity to commit to they have to keep into account that a considerable prediction error can determine a penalization for deviation and consequently reduce their profits.

Hence, studying the distribution of the prediction error allows on one hand, to hedge the risk to incur in undesirable penalizations that affect the economic result, on the other hand, betters the speculative potential of the seller.

Getting close to the real generation horizon, predictions get more reliable and final programming can be adjusted selling or buying energy in the intraday markets. As we have seen in the previous analysis, wind producers are net buyers in the intraday markets. That could depend on:

- Average negative error in the prediction;

- Preference in “inflating” sales bid in the day-ahead market to buy at lower prices in some sessions of the intraday market.

The existence of consultancy societies that get paid to improve market performance of different types of generation units suggests that some room is left for wind producers to design their own business strategy: being aware of their speculative potential, companies would reduce useless costs of consultancy and define their own risk profile.

So, the aim of a wind energy company is to determine the optimal sale bid in the day-ahead market of day D-1 to maximize the expected profit in day D, i.e. the sum of incomes achievable in both day-ahead and intraday markets minus the cost of deviation for all the 24 hours.

Perfect information on generation and market prices is not available, so in the next sections we will include these two sources of randomness and look for the optimal sale bid that accounts for both of them.

5.1. Stochastic optimization model with generation forecasts' scenarios.

First, we maximize the expected profit of a wind producer keeping into account the error in generation forecasting and consequent penalizations it would cause.

To be conservative we assume that we incur in a penalization any time that our final programming is greater than real generation. Actually we will not observe real generation in our decision horizon. What we will observe is a series of updates in generation prediction, the closest to real generation time being the most reliable.

The design of a commercial strategy and consequent determination of final programming for a wind producer can be regarded as the result of two successive decision processes:

1. Sending a sale bid to the day ahead market when 07.30 generation forecasting is received;

2. Determine the adjustments to be made in the intraday markets, when the last update in the prediction is received before first intraday market session closes.

That is the reason why we will use a two-stage stochastic linear optimization model, where the first stage variable will be the sale bid in the day-ahead market and the second stage variables will be the offer bids (quantity to sell/buy) in the six sessions of intraday markets.

The model will include some restrictions mainly due to technical bindings determined by market rules previously analyzed and producers' preferences.

The problem to solve will be:

$$\max \sum_{i=1}^{24} \lambda_i * x_i + \sum_{s=1}^{S} p^s \left[\sum_{j=1}^{m} \sum_{i \in A(j)} \pi_{ij} * y_{ij}^s - \sum_{i=1}^{24} c_i * \left(x_i + \sum_{\forall j \mid i \in A(j)} y_{ij}^s - g_i^s \right) \right]$$

s.t. $\alpha * \bar{e}_i \leq x_i \leq b \qquad i = 1, \dots, 24 \qquad (1)$

$$y_{i1}^s \geq -\beta * x_i \qquad i = 1, \dots, 24 \quad s = 1, \dots, S \qquad (2)$$

$$g_i^s \leq x_i + \sum_{\forall j \mid i \in A(j)} y_{ij}^s \leq b \qquad i = 1, \dots, 24 \quad s = 1, \dots, S \qquad (3)$$

$$0 \leq x_i + \sum_{\forall j \leq n \mid i \in A(j)} y_{ij}^s \leq b \qquad i = 1, \dots, 24 \quad n = 1, \dots, 5 \quad s = 1, \dots, S \qquad (4)$$

$$-\gamma_j * b \ , \leq y_{ij}^s \leq \gamma_j * b \qquad i = 1, \dots, 24 \quad j = 1, \dots, m \quad s = 1, \dots, S \qquad (5)$$

The parameters of the model are:

λ_i that is the hourly equilibrium clearing price in day-ahead market;

p^s that is the probability assigned to generation scenario s;

π_{ij} that is the hourly clearing price in intraday market j;

m, that is the number of sessions of intraday market;

c_i that is the hourly positive deviation cost;

$\bar{e}_i$ that is the last generation forecast received before daily market session closes;

g_i^s that is the expected generation in scenario s;

b that is the installed capacity of the wind farm;

γ_j that is the maximum percentage of total capacity offered in intraday market j;

α, β that are arbitrary parameters that define the lower bounds for energy quantities in day-ahead and first session of intraday market.

The variables are:

x_i the hourly sale bid in the day-ahead market, that is the first stage decision variable;

y_{ij}^s is the energy hourly quantity to sell/buy in session j of the intraday market for generation scenario s. Those are the second stage variables defined on the sets $A(j)$ that indicates the hours belonging to market j window.

In the objective function the first term $\sum_{i=1}^{24} \lambda_i * x_i$ represents total income obtained in the day-ahead market, as the sum for the 24 hours of the day of the product between the hourly market clearing price and the sale bid.

The second term $\sum_{i=1}^{24} \sum_{j=1}^{m} \left(\sum_{i \in A(j)} \pi_{ij} * y_{ij}^s \right)$ is the total income achieved participating to the six sessions of the intraday market. That is the sum of the incomes achieved for all hours belonging to the window of any market session j in all intraday market sessions: that will be negative if the producer is buying and positive if he is selling energy.

The third term $\sum_{i=1}^{24} c_i * \left[x_i + \sum_{\forall j \mid i \in A(j)} y_{ij}^s - g_i^s \right]$ represents total loss due to penalizations. That is the sum for all the 24 hours of the day, of the product of hourly deviation cost and difference between final programming and expected generation in scenario s. We assume to keep this difference positive and incur in a negative deviation since, as explained in session four, the probability of being penalized in this case is negligible (because decrease in industrial demand due to economic crisis cause energy demand to be lower than offer). This term strictly depends on the random component of the model, the prediction error. We prefer to be conservative and include it as if we would always incur in a penalization every time we offer more energy than what we expect to produce.

Restriction (1) prescribes to sell in the daily market at least a certain fraction of the generation forecast received and, trivially, not to commit more than wind farm installed capacity.

From a merely mathematical point of view, lower bound should be zero. Unfortunately zero for a wind power plant means "unavailable", with consequently restrictions on the offer bid to present in the next sessions of the production market: a producer cannot declare to produce zero and suddenly sale a considerable energy quantity.

Moreover, in the Electricity Market Activity Rules at paragraph 10.4 "Notifications of production forecast for each production unit", the right to require generation predictions to special regime producers is reserved to the regulator. Since he has to grant energy demand and offer to continuously match, if detects systematic offers lower than registered predictions could consider anti-competitive the behavior of a wind producer (that has priority in the dispatch) and sanction it.

Restriction (2) binds the energy a producer can buy in the first intraday market to a certain percentage of the quantity sold in the day-ahead market. That is generator has to be able to produce at list a minimum of the energy quantity committed in the market. Intraday markets are supposed to be "adjustment markets": a generator should not systematically buy energy if he is not capable to produce it at all.

Restriction (3) links final production programming to expected generation. As explained in section 4, data on wind energy producers' market behavior show a clear preference for a negative deviation in production associated to a negligible probability to incur in penalization. So we will ask final programming to be greater or equal than expected generation and lower than installed capacity. We prefer to account for penalization (including it with probability one) even if we will have to actually pay it only if an excess of demand is registered in the production market.

Restriction (4) is trivial: a producer never offers negative energy quantities neither more than the maximum he is capable to produce for any hour and any time of negotiation.

Restriction (5) bounds energy quantity offered into intraday markets to a certain percentage of the installed capacity, decreasing as long as markets close and generation horizon comes closer. That is because market regulator expects the adjustments to be decreasing and size of transactions becoming smaller. For example, he could consider as an anti-competitive behavior selling half of the capacity installed at last session of the intraday market.

In this first model, market prices and deviation cost vectors have been included as fixed parameters. Price curves for day D will be equilibrium hourly prices for day D-1 while previous month average data have been used for hourly deviation costs.

As explained above, wind producers receive the last prediction useful to formulate their offer to the day-ahead market at 07.30 in the morning of day D-1. That means the real production horizon is far from the prediction moment and can be bettered as long as we get close to it. That is the reason why, a wind producer has to take into account this change in the precision of the forecast and include in the formulation of its strategy the forecasting error.

That will be the random component of this first model. It has been studied using historical monthly observations. In the following section we will explain in details how it has been modeled and introduced in the objective function.

Expected generation will be the sum of energy production forecasting and prediction error. Since error scenarios are constructed independently on the prediction received, it is necessary to check that the sum of the two components does not exceed total installed capacity. If this happens, sum should be replaced by wind farm capacity.

Optimal solution will represent the best sale bid in day-ahead market that accounts for any possible observation of the error associated to the generation forecast.

The true value assumed by this variable will only be observed after the closing of the daily market and a new optimization problem will have to be solved in order to take corrective actions (buy/sell energy in the intraday markets) and determine the optimal final programming.

5.1.1. MODEL IMPLEMENTATION USING REAL DATA.

Model has been implemented using real data provided by FERSA Renewable Energy S.A., a renewable energy company successfully operating in Spain with approximately 140 MW of wind capacity installed and 120 MW installed worldwide.

The company has an internal operation department that continuously monitors the activity of the operative wind farms and has also contracted an external expertise in wind predictions that calculates hourly generation estimates all day long and checks for turbines availability.

Predictions of 07.30 a.m. of day D-1 are automatically registered in the electronic data system of Fersa’ s market agent and constitute daily offer for day D for the correspondent wind farm if no other bid is sent before daily market closing time (10 a.m.).

Fersa has contracted a consultancy company that operates as a market intermediary with its agent, “manipulating” predictions’ results and granting an increase in monthly profits. The general strategy detected is exploiting price difference between markets selling more in the day-ahead market and buying cheaper in the first two sessions of the intraday market. The consultancy company has free access to generation predictions so that, when a significant error is detected, adjustments in final programming are made not to incur in a considerable deviation.

Fersa aims to eliminate this consultancy costs and improve its benefits by developing its own efficient business strategy.

Fersa’s portfolio includes wind farms subject to different economic regimes that can be divided into three main groups:

1. Group 1→ wind farms under RD 436/2004 that chose the “market option”

2. Group 2→ wind farms under RD 661/2007 that chose for this year the “market option”

3. Group 3→ wind farms promoted but not operating, awaiting new regulation to be financed and constructed.

All groups have a strong necessity to perform efficiently in the market since their incomes are strictly related to fluctuations in prices and predictions' reliability.

Installations in group 3 will have to be prepared to an expected "revolution" in the system that will ask wind energy to compete with other technologies without a sufficient support by the government.

The wind farm used for model implementation is operating since 2007 under RD 436/2004, and has a total installed capacity of 16.2 MW.

Real price data have been downloaded from market operator web page (www.omel.es).

Hourly deviation costs are not published daily. They become available once the company receives its monthly invoice. So, average data from the previous month are the best available ones.

We solve the model using α equal to 0,9: that is because historically deviation percentage in predictions for the wind farm analyzed is 10%.

We choose β equal to 0,8: that means we can buy in the first intraday market at most the 80% of what we sold in the day-ahead market. This parameter is totally arbitrary and measures the risk profile of the producer: the greater β the greater the possibility of the regulator detecting some weird behavior in the offer strategy of the company.

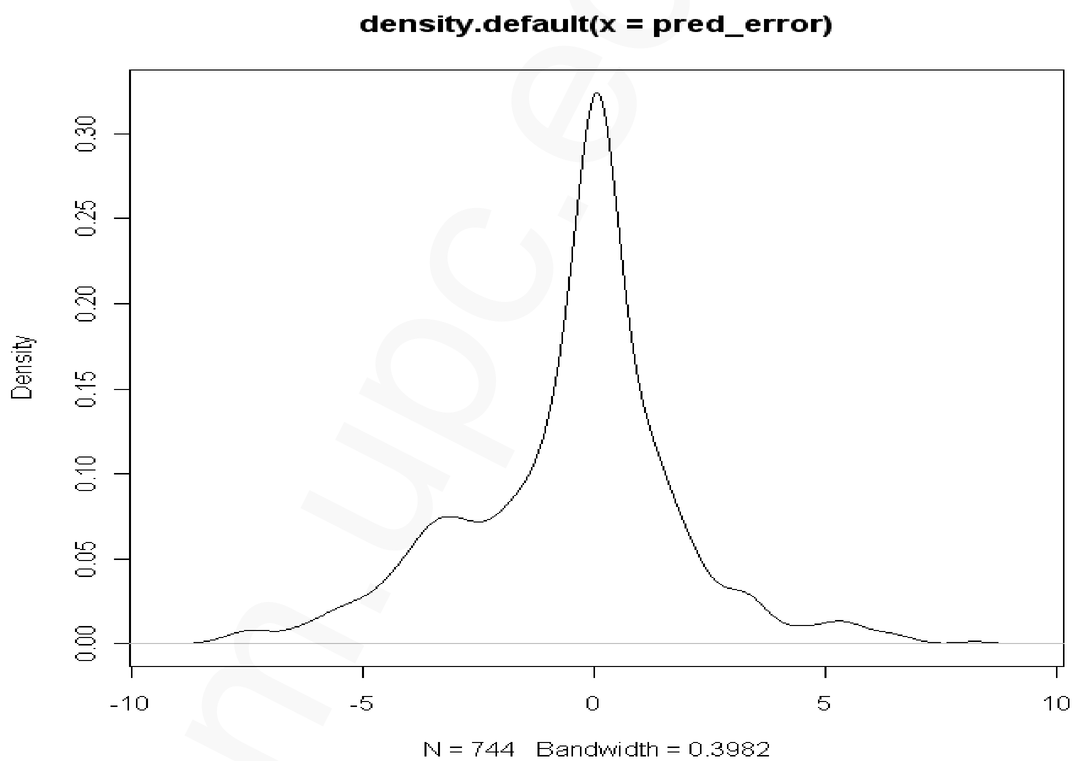
Upper bound for hourly energy offer in daily market and final programming will be total installed capacity, even if the probability for a wind farm to produce the maximum is very low.

The parameters γ_j will assume the following values: $\gamma_1 = 0{,}6\,; \gamma_2 = 0{,}55\,; \gamma_3 = 0{,}5; \gamma_4 = 0{,}45\,; \gamma_5 = 0{,}4\,; \gamma_6 = 0{,}35$. Those are considered to be reasonable values to bind offer size in intraday market sessions.

Hourly errors in the 7.30 predictions registered in April, May and June 2011 have been calculated. The data observed provide some important information on the prediction:

- the error has been observed to be homogenous across the day, i.e. no correlation exist between the same hours of different days;
- average error is typically negative, i.e. we are underestimating generation;
- the empirical distribution can be approximate to a normal random variable;
- error distribution does not vary considerably from one month to another.

To formulate error scenarios we used data from May 2011, considered to be the most representative. Using the program for statistical computing and graphics R, we have plotted the empirical density function showed in the following graph.



That can be approximate by a Normal distribution with mean -0,4754032 and variance 5,3553.

Since observations can be assumed to be from an independent and identically distributed population, a bootstrapping procedure can be implemented by constructing a number of resamples of the observed dataset, obtained by random sampling with replacement from the original dataset.

Using this procedure a random sample of 200 values has been generated and 64 scenarios for the prediction error have been constructed calculating the respective probabilities.

AMPL software has been used to implement the model, choosing simplex as the optimizer.

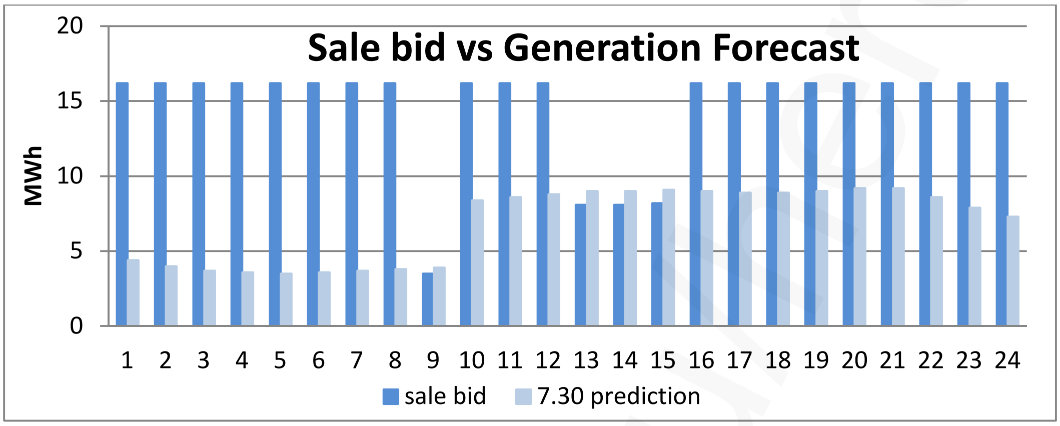
5.1.2. Generation scenarios: case (a)

In the first implementation we use price data from 04/10/2010 showed in the following table.

	MD	INT1	INT2	INT3	INT4	INT5	INT6
1	36,53	26,53	7,31				
2	28	0,01	5				
3	10,07	0	0				
4	10	0	0				
5	10,07	0,01	0	0			
6	10,07	0,01	5	3,02			
7	37,43	26,2	10	11,23			
8	48,97	48,97	48,97	48,97	48,97		
9	46,2	48,2	49,85	47,44	46,34		
10	49,1	48,11	48,73	49,11	49,1		
11	48,51	48,51	48,51	48,68	48,51		
12	48	48	47,53	47,53	48	40	
13	48,51	48,51	47,79	48,51	48,54	45	
14	47,51	47,51	47,51	47,54	47,54	40,38	
15	46,27	46,27	46,27	46	46,3	39,33	
16	48,27	48,27	48,27	48,27	48,3	48,76	42,27
17	48,27	48,27	48,27	48	48,28	48,27	33,79
18	49,51	48,59	48,59	49	49,51	49,51	34,66
19	50,27	47,87	47,87	49,27	50,27	49,27	35,19
20	52,01	44,21	46,81	46,81	46,81	46,81	26,01
21	57,21	54,21	54,21	54,35	54,21	54,21	50,92
22	57,12	50,09	50,09	51	51	52,84	50,84
23	52,57	44,68	44,68	45,21	45,21	47,31	46,79
24	49,1	41,6	41,6	41,74	44	44,19	44,44

This is an interesting case since some zero in clearing price curves have been registered and there is room for "speculation" in many hours of the day.

In the following graph optimal solution (day-ahead prescribed sale bid) and generation forecast of 7.30 are showed.

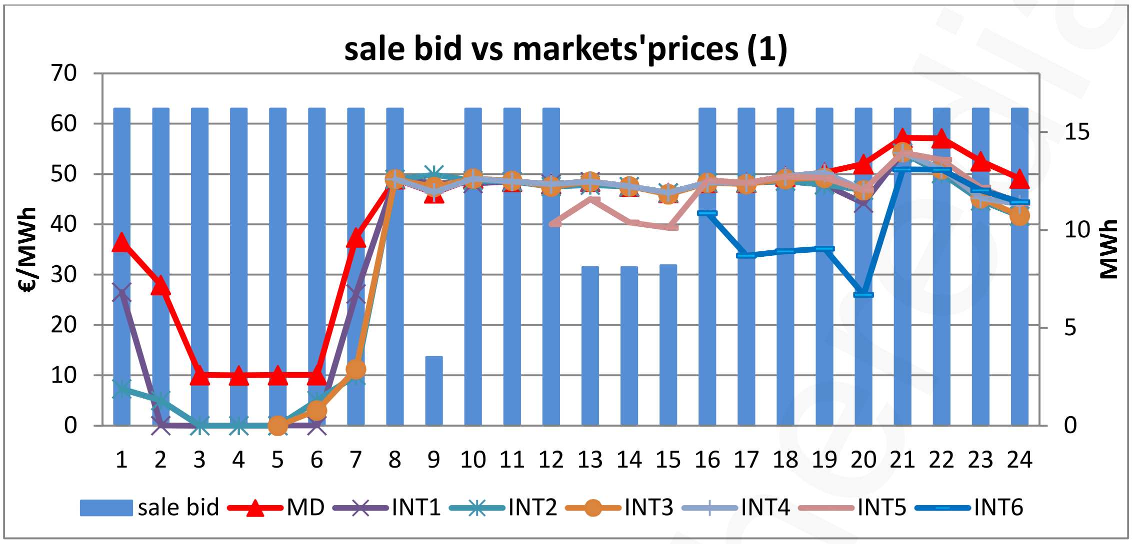


We can notice that the optimal solution prescribes to commit total capacity in all but hours 9, 13, 14, 15 where is optimal to sell the minimum.

If common practice defining strategies based only on price differences in market sessions were optimal, the result would only depends on day-ahead hourly price to be lower than any other price registered in the intraday market.

Apparently, when selling is strictly more profitable in the day-ahead market than in at least one session of the intraday market, the optimal hourly strategy prescribes to sell the maximum and buy the default quantity in those cheaper sessions. The other way around, if intraday markets show greater clearing prices than day-ahead market, the best is to offer the minimum (that in this case is 90% of the prediction) and then sell the excess energy. How much to sell/buy in intraday session is determined solving another maximization problem, once error in the 7.30 prediction is observed.

Relationship between solution and market prices is shown in the following graph:



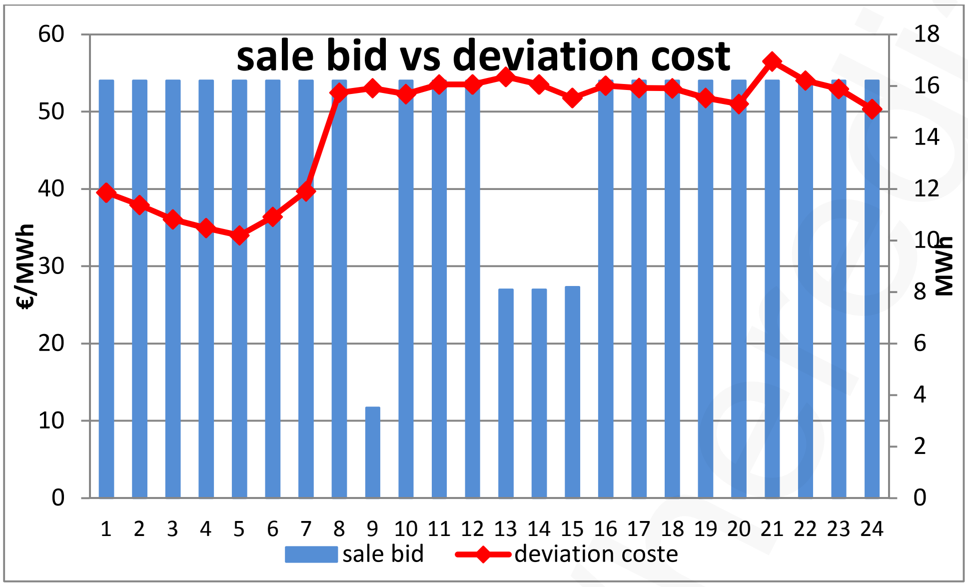
In hour 9 for example, day-ahead is the cheapest market so that we would offer the minimum but that is not the case in hours 13, 14 and 15 where minimum price is registered in session 5 of intraday market.

In this case the results depend on size of the 7.30 hourly predictions and restriction (5) on offer bid size in intraday markets: the producer cannot risk waiting session 5 to sell the amount of energy that would give him an extra benefit because it does not want to incur in a sanction or in a considerable market penalization.

That would explain the necessity to be conservative in selling/buying in intraday markets and to keep into account deviation costs.

If we look at deviation cost curve we notice how, even if hourly costs are greater than prices in the majority of hours, we can offer the maximum as long as we are able to annul the deviation by fixing the final program at expected generation.

In hours 13, 14 and 15 that is not possible because of restriction (5).



We can affirm the solution strictly depends not only on price differences but also on transaction “size” and deviation costs.

In order to show how the solution changes according to price relationship, we repeat the optimization procedure with different clearing prices.

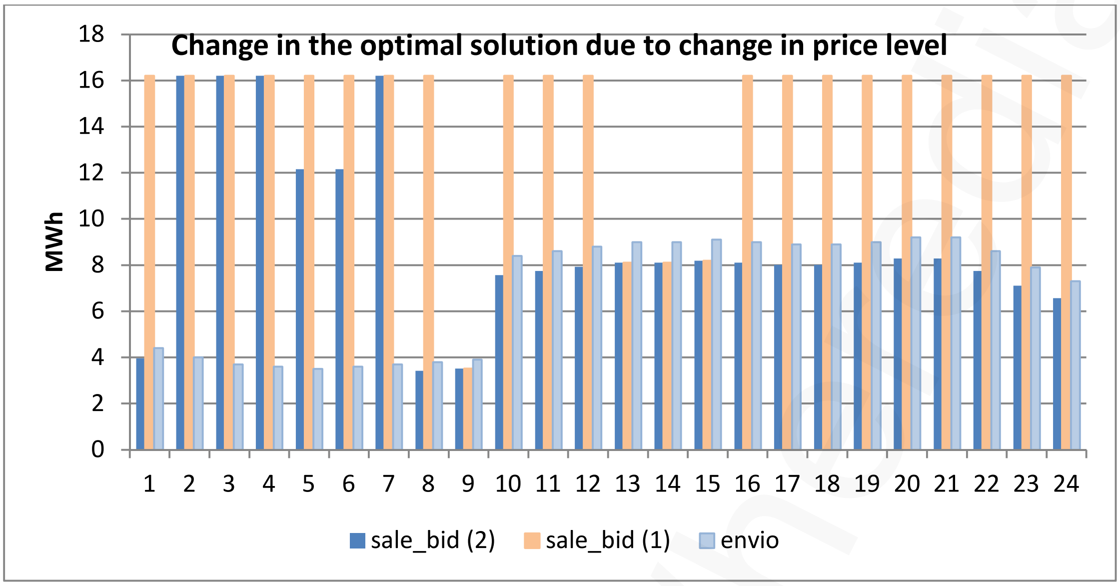
5.1.3. Generation scenarios: case (b)

We now implement the model using price data from 01/07/2011. The choice of more recent equilibrium prices is not by chance. Market prices have increased in the last six months because of petroleum crisis and law on national carbon. Additionally, a reduction in inter-hours price volatility has been detected.

Data on price curves are reported in the following table.

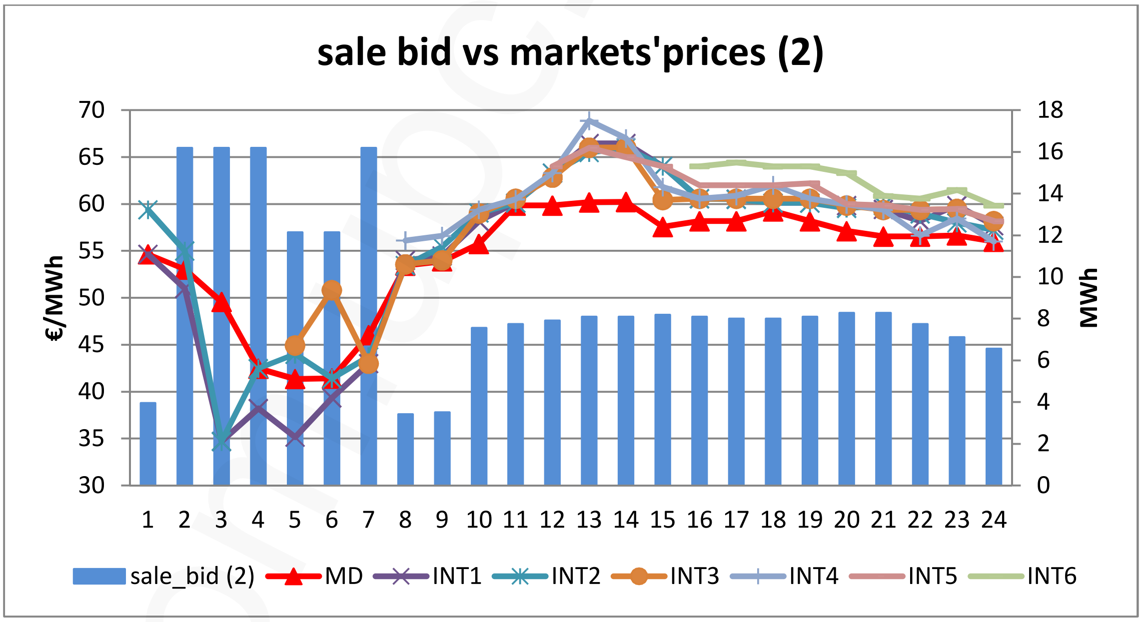
	MD	INT1	INT2	INT3	INT4	INT5	INT6
1	54,65	54,65	59,39				
2	53,03	51	55				
3	49,57	34,7	34,7				
4	42,46	38,21	42,46				
5	41,36	35,16	44	44,93			
6	41,41	39,34	41,41	50,82			
7	46,03	43	43,73	43			
8	53,45	54	53,45	53,57	56,12		
9	53,9	54,47	55,44	54	56,6		
10	55,75	58,18	59,05	59	59,39		
11	59,84	60,11	60,11	60,57	60,5		
12	59,84	63,3	63,3	62,83	63,3	64,02	
13	60,18	66,45	65,49	66,01	68,88	66	
14	60,22	66,45	66	66,01	67	65	
15	57,56	64,02	64,02	60,44	61,8	64	
16	58,17	60,57	60,57	60,57	60,57	62	64,02
17	58,17	60,52	60,51	60,57	60,87	62	64,42
18	59,23	60,11	60,11	60,57	62	62	64
19	58,17	60,11	60,11	60,57	60,57	62,22	64,02
20	57,11	59,84	59,55	59,84	59,96	60	63,3
21	56,54	59,44	59,84	59,37	59,37	59,84	60,87
22	56,54	58,18	58,96	59,37	56,64	59,39	60,57
23	56,66	59,84	58	59,49	58,47	59,49	61,5
24	56,01	57,69	57,22	58,18	56,01	58,18	59,84

In this case price relationship is not that obvious. We draw the solution obtained together with the 7.30 prediction and previous solution to detect how optimal solution changes and we see how it considerably varies with respect to the one previously obtained.



In hours 2,3,4 and 7 when clearing price in day-ahead market is greater than in all sessions of intraday markets and no restriction on transaction size is active, the optimal strategy still prescribes to offer the maximum, while in hour 1 and from hour 8 to 24 it is optimal to offer the minimum.

The reason of that can be seen in the following graph, showing sale bid and price curves in all markets.



From hour 2 to 7 daily market price is greater than at least one of the intraday market price, while in all the remaining hours day-ahead market price is the minimum achievable.

Interesting study cases are hours 5 and 6: the cheapest market session is intraday one but restriction (1) imposes not to buy more than 80% of what sold in the day-ahead market in that session. Moreover bounds on transactions sizes do not allow buying or selling more than 60% of total capacity.

We can detect some properties of the optimal hourly strategy:

- It prescribes to offer more than the predicted generation if there is a possibility to buy the default energy at a lower price in at least one session of the intraday market, avoiding to incur in a penalization;

- It is optimal to commit to the minimum if energy can be sold at higher price in the following market sessions;

- Solution strongly depends on difference in hourly prices more than on price level.

So, wind producers that systematically inflate their offers into the day-ahead market to buy the default energy quantity in intraday markets are not applying an optimal strategy since market imperfection on prices create a high risk of undesirable losses and restrictions due to transactions' size and penalization costs should be taken into account.

Uncertainty in the production market, mainly due to changes in generation mix and demand level can be modeled including scenarios for intraday market prices.

5.2. Stochastic optimization model including scenarios for intraday markets' prices.

In the previous section we saw that optimal sale bid depends, together with the penalization cost and technical restrictions, on difference in price levels in the different sessions of the market.

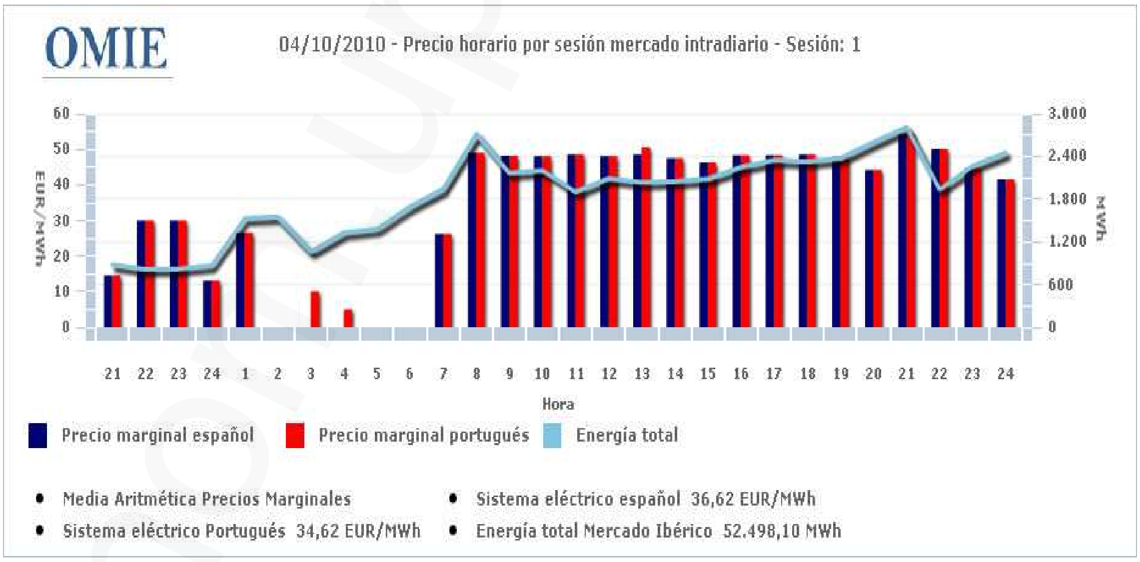
Electricity markets in general are characterized by considerable volatility in prices.

In spite of that, daily price curves show a sort of regularity in their shape mainly due to typical fluctuations in the demand from some range of hours to the other. We can detect:

- Peak- hours→ characterized by higher energy prices and greater system load, normally between 8 a.m. and 8 p.m.

- Off-peak hours→ night hours characterized by lower prices and system load, normally between 9 p.m. and 7 a.m.

An example of typical intraday market price curve (session one) is showed in the following graph from OMEL web page, were equilibrium prices and demand level are published every day after market closing time.



Moreover, time series of energy prices show different type of seasonality:

- Systems with a considerable presence of renewable energy in generation mix show yearly seasonality mainly due to water/wind conditions;

- On a weekly basis, demand (and hence prices) is lower during the week end than during working days;

- As previously seen, on a daily basis peak and off-peak hours can be distinguish.

Those characteristics are common to any of the market session.

Our aim is to make our objective function sensitive to changes in price level and include different scenarios for hourly clearing prices in intraday market.

That will allow, on one hand to include a measure of market volatility in the problem, on the other hand to be more prudent when exploiting price differences between the markets that are not "obvious".

The new linear two stage stochastic problem to solve will incorporate two sources of randomness, the one in generation forecasts and that in intraday hourly clearing market prices.

The problem to solve will be:

$$\max \sum_{i=1}^{24} \lambda_i * x_i + \sum_{s=1}^{S} \mathrm{p}^{\mathrm{s}} \sum_{r=1}^{R} \mathrm{q}^{\mathrm{r}} * \left[\sum_{j=1}^{m} \sum_{i\in A(j)} \pi_{ij}^{r} * y_{ij}^{s,r} - \sum_{i=1}^{24} c_i * \left(x_i + \sum_{\forall j \mid i\in A(j)} y_{ij}^{s,r} - g_i^s \right) \right]$$

$$\textbf{s.t.} \quad \alpha * \bar{e}_i \le x_i \le b \qquad i = 1, \dots, 24 \qquad (1)$$

$$y_{i1}^{s,r} \ge -\beta * x_i \qquad i = 1, \dots, 24 \qquad s = 1, \dots, S \quad r = 1, \dots, R \qquad (2)$$

$$g_i^s \le x_i + \sum_{\forall j \mid i\in A(j)} y_{ij}^{s,r} \le b \quad i = 1, \dots, 24 \quad s = 1, \dots, S \quad r = 1, \dots, R \qquad (3)$$

$$0 \le x_i + \sum_{\forall j \le n \mid i\in A(j)} y_{ij}^{s,r} \le b \qquad i = 1, \dots, 24, n = 1, \dots, 5 \quad s = 1, \dots, S \quad r = 1, \dots, R \qquad (4)$$

$$-\gamma_j * b \ , \le y_{ij}^{s,r} \le \gamma_j * b \quad i \in A(j) \quad j = 1, \dots, m \quad s = 1, \dots, S \; r = 1, \dots, R \qquad (5)$$

The parameters of the model are:

λ_i is the hourly equilibrium price in day-ahead market;

q^r is the probability assigned to price scenario r;

p^s is the probability assigned to generation scenario s;

π_{ij}^r is the hourly equilibrium price in intraday market j in scenario r;

m is the number of sessions of intraday markets;

c_i is the hourly positive deviation cost;

$\bar{e}_i$ is the last generation forecast received before day-ahead market session closes;

g_i^s is the expected generation in scenario s;

b is the installed capacity of the wind farm.

γ_j is the maximum percentage of total capacity offered in intraday market j;

α, β are arbitrary parameters that define the lower bounds for energy quantities in day-ahead and first intraday market.

The variables are:

x_i that is the decision variable, i.e. the hourly generation to sell in the day-ahead market;

$y_{ij}^{s,r}$ that is the quantity to sell/buy hourly in the intraday market j for price scenario r and generation scenario s defined on the correspondent market window, that is the set $A(j)$.

In the objective function the second term has changed including randomness in intraday market prices.

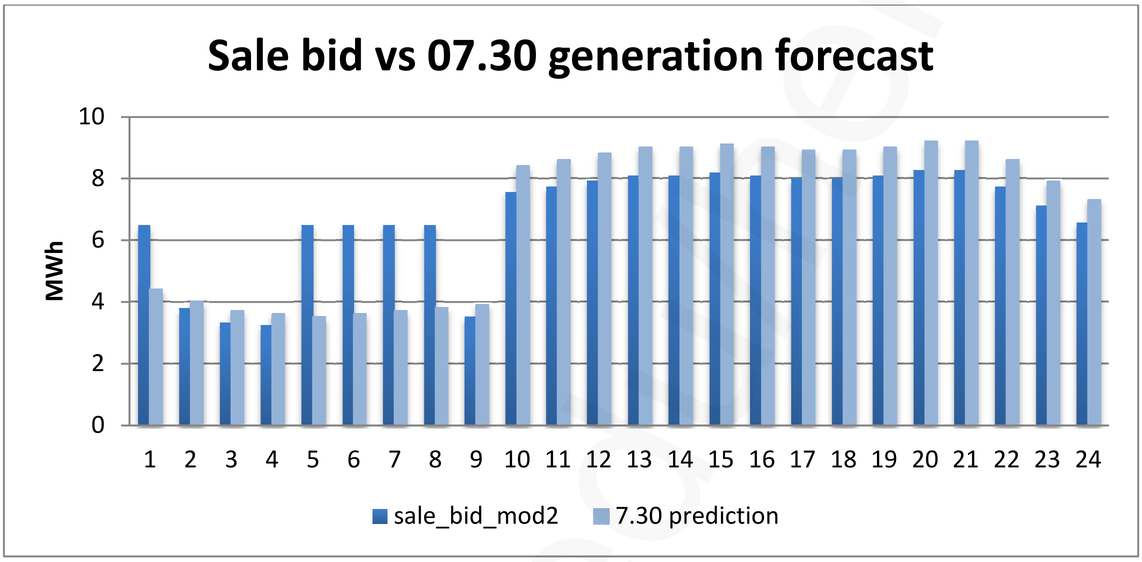
Restrictions and parameter values will be the same as before, together with day-ahead market clearing price and deviation costs.

Intraday market prices have not been considered as a single time series but as a set of 24 time series (one for each hour). 200 price scenarios generated by Cristina Corchero in her doctoral thesis "Short-term bidding strategies for a generation company in the Iberian electricity market", using time series factor model have been included. All scenarios are assumed to be equally probable.

5.2.1. Intraday market price scenarios: case (a)

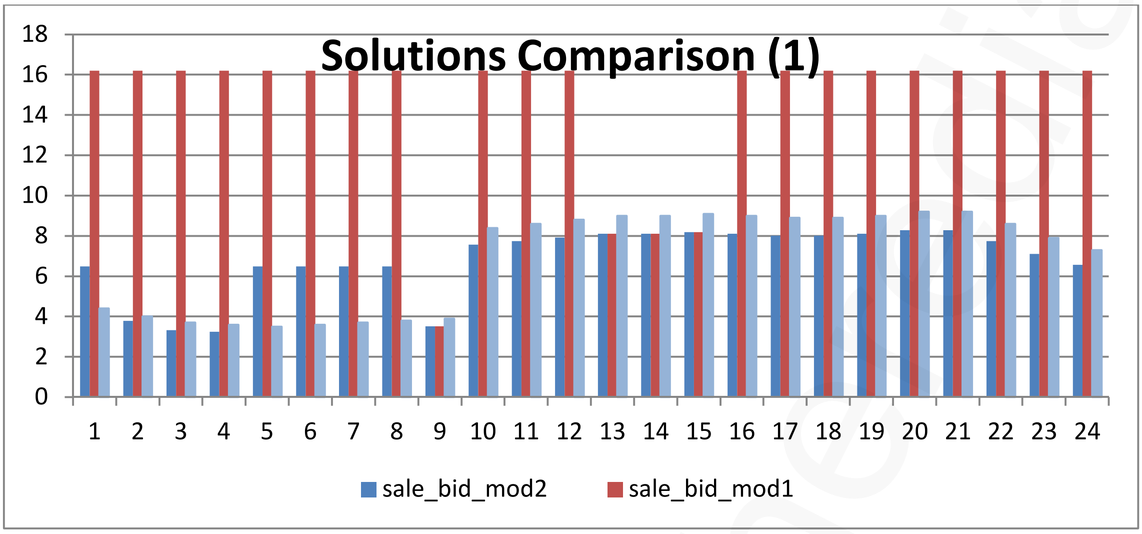
We first implement the model using clearing price for day-ahead market on October 4 2010 and average deviation costs of September 2010.

The results obtained are showed in the following graph.



The optimal solution prescribes to offer the minimum in the majority of hours. That is because clearing price curve in day-ahead market is quite low and it is better to sell in in the intraday market in all hours but 1, 5, 6, 7 and 8. In those hours we are not offering the maximum: that could be because of some restrictions on transactions volume to be active or on deviation costs.

We now look at how the solution changed compared to the previous model, where intraday market prices where kept fixed.



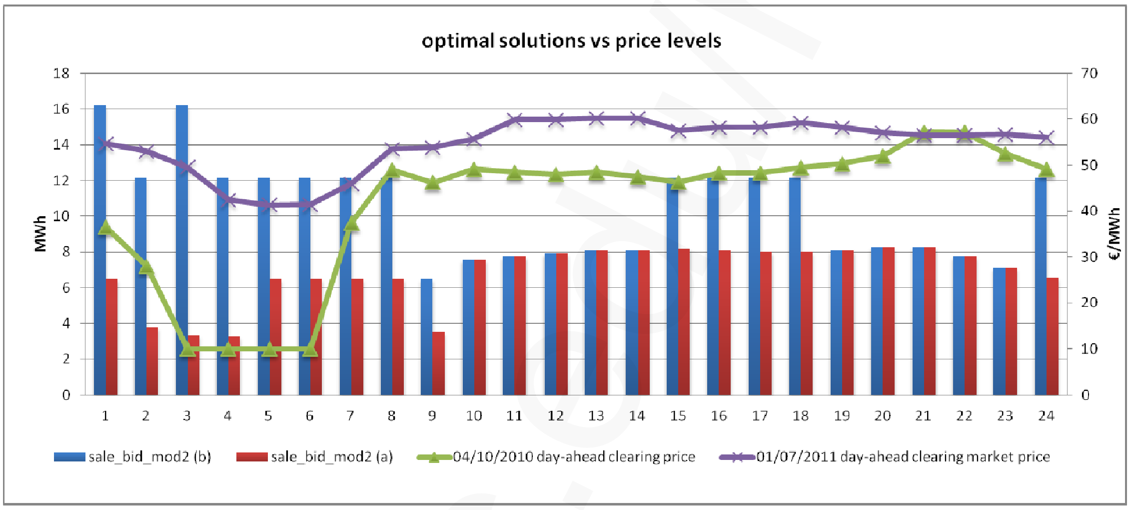
The effect of including scenarios for intraday market prices is clear: the new strategy prescribes to be prudent in any of the 24 hours of the day, a result opposite the one obtained implementing the first model. That is because intraday market curve, previously considered as a parameter, showed zeros in many hours. Now that we account for volatility in market prices, we keep into account the probability (high!) of price to be greater then the observed value. This probability is lower in hour 1, 5, 6, 7 and 8 where the new solution asks to sell more energy than forecasted. The predictions are only partially inflated, that is because of restrictions in admissible transaction size. Deviation costs are low enough not to substantially affect the solution.

5.2.2. Intraday market price scenarios: case (b)

We implement the model again with different day-ahead market prices (those of 1 July 2011) and average deviation costs of June 2011.

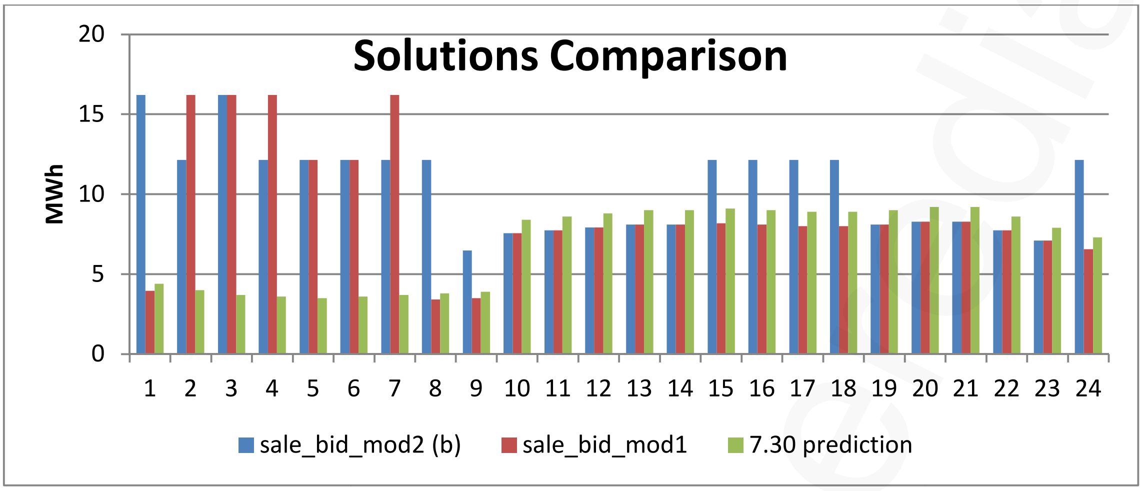
As previously stated economic crisis, Spanish carbon law and low wind production has caused price market to increase remarkably in the last three months and a change in inter-hours volatility has been detected as well.

We show in the following graph as a change in price level affect the solution.



The optimal solution obtained when day-ahead market prices are greater and show a reduced volatility, prescribes to sell more in those hours where price differences can be exploited. A peak is reached in hour 3, because of a low clearing price registered in that hour in the second session of intraday market.

A comparison with the optimal solution previously obtained using the model including generation scenarios is necessary to see the effects of including intraday price scenario in a context of high day-ahead market prices and deviation costs.



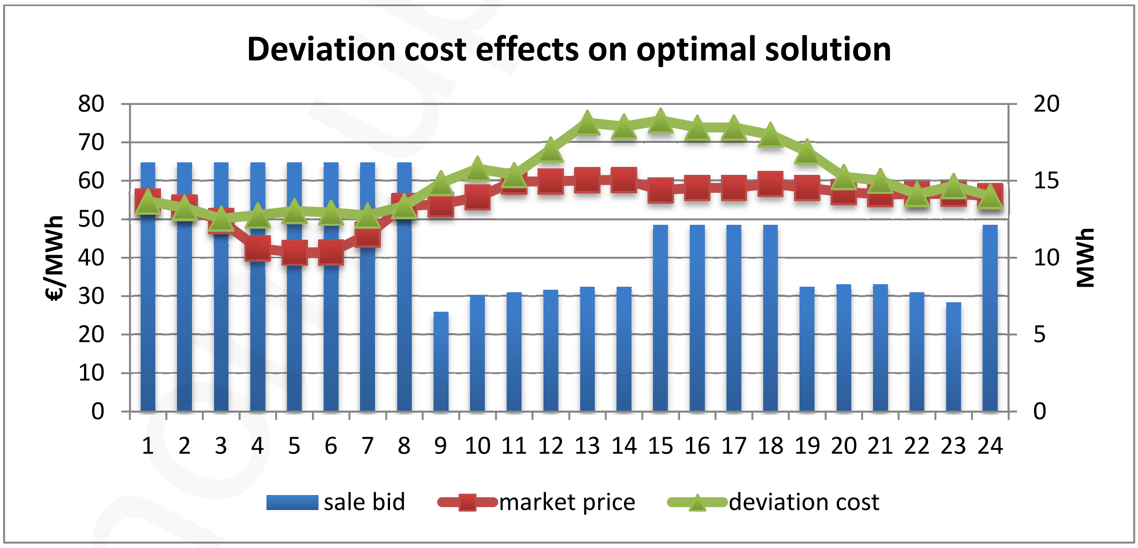
Again, keeping into account volatility in the market prescribes to be more conservative in some hours typically characterized by low prices and to be more aggressive in those hours that show lower clearing prices.

This is an interesting case study to show the importance of including the penalization component in the objective function.

We solve the model including price scenarios and generation scenarios, eliminating the losses due to deviation penalizations, all the restrictions being the same as before.

The solution obtained is the same for hours 9 onward but is much more risky in the first hours when it recommends to sell total capacity in the day-ahead market.

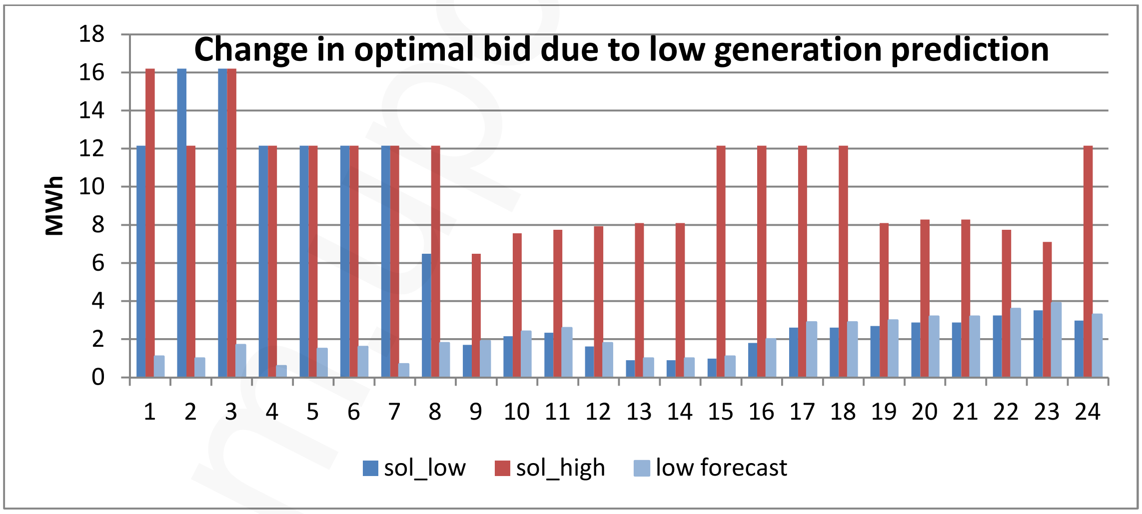
Looking at the graph showing day-ahead market price and deviation cost curves we can see in details where the results come from.



Deviation costs only affects optimal sale bid for the first hours of the day when a lower number of intraday markets are available for adjustments. In this case, restrictions on transactions volumes make it impossible to annul the deviation by offering a final programming equal to the expected generation.
In the rest of hours it is strictly optimal to sell rather than buy electricity, so that in any scenario the solution prescribes to buy energy up to total installed capacity. The final programming will be total capacity sold in any hour of the day, while keeping into account deviation costs it will be equal or a bit slightly greater than expected generation: that is because deviation costs are higher than prices of the last sessions of intraday market.
That let us believe that the deviation cost will have a greater and clearer impact on decisions on adjustment variables.

One could think that the possibility to speculate depends on the type of prediction received: should a lower prediction live enough room for more speculations? Lower bounds of any of the restrictions will change according to that.

We use data on prediction sent in a day of bad wind conditions and see how the solution changes.



The effect on the optimal solution is controversial:

- On one hand, a lower generation forecast implies a greater risk to incur in penalization when inflating the sale bid in the day-ahead market. So some restrictions that were not active will now become active. That is the case of hours 1, 8, 15, 16, 17, 18 and 24.

- On the other hand, admissible region of the problem becomes bigger and some greater optimal hourly sale bid can be obtained as in hour 2.

The solution prescribes to offer the minimum in all those hours that are risky in terms of price differences and higher deviation costs.

5.3. Value of the Stochastic Solution

The value of the stochastic solution (VSS) can be interpreted as the potential benefit from solving the stochastic program over solving a deterministic program in which expected values have replaced random parameters.

The VSS is the difference between the goal value for the stochastic problem, and the average goal value over all scenarios when the non-recourse decisions are fixed to their values in the expected value problem. If this difference is small, then that indicates that using the solution of the expected value problem will likely lead to a "pretty good" solution to the stochastic problem. In other words, the randomness does not play a very significant role. This is not the same as saying that the amount of randomness in the problem is "small".

In our model we introduced two sources of randomness, one due to prediction error and the other due to volatility in intraday market prices. The cost has been pretty high since 64 scenarios have been considered for the error and 200 for prices.

We maximize the utility function $u(x, g, \pi)$ and obtain the optimal solution x* that will provide an average utility of $u^*(x^*, g, \pi)$.

We will now maximize the expected utility, i.e. we will solve the following problem:

$$\max \sum_{i=1}^{24} \lambda_i * x_i + \sum_{j=1}^{m} \sum_{i \in A(j)} \bar{\pi}_{ij} * y_{ij} - c_i * \sum_{i=1}^{24} \left[x_i + \sum_{\forall j \mid i \in A(j)} y_{ij} - \bar{g_i} \right]$$

$$\textbf{s.t.} \quad \alpha * \bar{e}_i \leq x_i \leq b \qquad i = 1, \dots, 24 \tag{1}$$

$$y_{i1} \geq -\beta * x_i \qquad i = 1, \dots, 24 \tag{2}$$

$$\bar{g_i} \leq x_i + \sum_{\forall j \mid i \in A(j)} y_{ij} \leq b \quad i = 1, \dots, 24 \tag{3}$$

$$0 \leq x_i + \sum_{\forall j \leq n \mid i \in A(j)} y_{ij} \leq b \qquad i = 1, \dots, 24, n = 1, \dots, 5 \tag{4}$$

$$-\gamma_j * b \ , \leq y_{ij} \leq \gamma_j * b \qquad j = 1, \dots, m \tag{5}$$

where $\bar{\pi}_{ij} = \sum_{r=1}^{R} q^r * \pi_{ij}^r$ and $\bar{g}_i = \sum_{s=1}^{S} p^s * g_i^s$. We indicates the optimal solution of this problem as $\bar{x}$ and maximize the function $u(\bar{x}, g, p)$ obtaining $u^*(\bar{x}, g, p)$.

$$\text{VSS} = u^*(x^*, g, \pi) - u^*(\bar{x}, g, \pi)$$

We calculate the VSS of the model for both observations of intraday market prices and deviation costs considered.

Case (a) with data from 04/10/2011 gives a VSS value of:

(12.155€ - 12.032€)=133€

while case (b) with data from 01/07/2011 gives a VSS value of:

(11.269-9.145)=2124€

We are maximizing the daily profits of a wind producer for one of its plant: the improvement in the solution is considerable if we consider that it can be achieved daily and that the same optimization method can be applied to all other wind farms in operation. The results suggest that it is worth introducing randomness in the model even if a great number of variable and restrictions have to be introduced.

In the following table we report the number of variables and restrictions and execution time of both models implemented with machine Fuji Rx200 56 (2XCPUs Intel Xeon X5680 Six Core/RT 3.33 GH, 64Gb RAM).

Model	#x	#y	#restrictions	Execution Time
With generation scenarios	24	6848	17.624	30 sec
With generation and price scenarios	24	1.369.600	3.520.024	9 min 45 sec

Conclusions

The objective of this work is to look for new optimal commercial strategies for wind power producers, required to increase their performance in the production market.

The results obtained by implementing both models provide important information on common practice currently used in the market. It is not optimal to construct the sale bid systematically inflating the last prediction received before market closes and buy the default energy quantity in first and second sessions of the intraday market. That is quite risky in a system where change in price level and volatility is taking place and uncertainty calls for prudency.

Including in the objective function, randomness due to error in generation predictions, we are trying to limit the risk of incurring in penalization and create more room for speculation (the greater the knowledge on expected generation, the greater the possibility to operate efficiently into the market).

The results show that optimal solution does not depend only on difference in price level in the different sessions of the market but also on transactions' size and deviation costs. We can state that expected difference in price level generally determines what to do: optimal solutions generally prescribe to inflate predictions when day-ahead market price is greater than intraday markets' prices, while offering the minimum when the opposite occurs.

For this reason we have included scenarios for intraday market prices keeping day-ahead clearing prices as a fixed parameter. That allows considering many possible market circumstances and relationship between price levels in the different market sessions.

The solution obtained varies according to price scenarios, prescribing to be prudent where there is room for speculation due to a positive difference in price levels. Only when the probability of day-ahead market price to be greater than intraday markets' prices is high, typically during the off-peak hours, and no restriction on transactions' size is active, the solution suggest to offer the maximum.

Deviation costs has to be included to be considered that, if a producer does not have enough room to adjust the final programming and sell to much in the day-ahead market, he would sensibly reduce his profit.

Solutions obtained including price scenarios are more prudent than the ones only accounting for generation scenarios.

Through the calculation of the Value of the Stochastic Solution we have showed that there is a considerable benefit to include both generation and price scenarios in the objective function.

Further improvement of the model could be obtained considering the correlation between the different market price curves to better modelling the dependency on the solution on market volatility.

Moreover, the model has been implemented considering only positive deviation costs, since it was adequate in a context of low market demand. It would be interesting to include in the model some scenarios on relationship between energy demand and offer, and associated deviation costs.

Appendix A

Documents .mod and .dat used to implement the first model with generation scenarios.

Intradiario.mod

```
set HORAS:={1..24};
set VENTANA3:={5..24};#ventana intradiario 3
set VENTANA4:={8..24};#ventana intradiario 4
set VENTANA5:={12..24};#ventana intradiario 5
set VENTANA6:={16..24};#ventana intradiario 6
set ESCENARIOS:={1..64};#escenarios de generación

param precio_md {HORAS};
param precio_int1{HORAS};
param precio_int2{HORAS};
param precio_int3{VENTANA3};
param precio_int4{VENTANA4};
param precio_int5{VENTANA5};
param precio_int6{VENTANA6};
param coste {HORAS};
param envio {HORAS};
param error{s in ESCENARIOS};
param prob{s in ESCENARIOS};
param lambda;
param capacidad;
param g {i in HORAS, s in ESCENARIOS} := if envio[i] + error[s] > capacidad
then capacidad else envio[i] + error[s] ;

var gen_md{i in HORAS}>=0.9*envio[i];
var gen1{i in HORAS, s in ESCENARIOS}<= 0.6*capacidad, >= -0.6*capacidad;
var gen2{i in HORAS, s in ESCENARIOS}<= 0.55*capacidad, >= -0.55*capacidad;
var gen3{i in VENTANA3, s in ESCENARIOS}<= 0.5*capacidad, >= -0.5*capacidad;
var gen4{i in VENTANA4, s in ESCENARIOS}<= 0.45*capacidad, >= -0.45*capacidad;
var gen5{i in VENTANA5, s in ESCENARIOS}<= 0.4*capacidad, >= -0.4*capacidad;
var gen6{i in VENTANA6, s in ESCENARIOS}<= 0.35*capacidad, >= -0.35*capacidad;

maximize Profit:

sum{ i in HORAS}gen_md[i]*precio_md[i]
+sum{s in ESCENARIOS}prob[s]*(sum{i in HORAS}(gen1[i,s]*precio_int1[i] +
gen2[i,s]*precio_int2[i])
+sum{i in VENTANA3}gen3[i,s]*precio_int3[i]
+sum{i in VENTANA4}gen4[i,s]*precio_int4[i]
+sum{i in VENTANA5}gen5[i,s]*precio_int5[i]
+sum{i in VENTANA6}gen6[i,s]*precio_int6[i]
-sum{i in
VENTANA6}coste[i]*(gen_md[i]+gen1[i,s]+gen2[i,s]+gen3[i,s]+gen4[i,s]+gen5[i,s]
+gen6[i,s]-g[i,s])
-sum{i in VENTANA5 diff
VENTANA6}coste[i]*(gen_md[i]+gen1[i,s]+gen2[i,s]+gen3[i,s]+gen4[i,s]+gen5[i,s]
-g[i,s])
-sum{i in VENTANA4 diff
VENTANA5}coste[i]*(gen_md[i]+gen1[i,s]+gen2[i,s]+gen3[i,s]+gen4[i,s]-g[i,s])
-sum{i in VENTANA3 diff
VENTANA4}coste[i]*(gen_md[i]+gen1[i,s]+gen2[i,s]+gen3[i,s]-g[i,s])
-sum{i in HORAS diff VENTANA3}coste[i]*(gen_md[i]+gen1[i,s]+gen2[i,s]-
g[i,s]));

subject to Restriccion{i in HORAS}:#la programación en mercado diario tiene
que ser superior al envio y menor que el 80% de la capacidad
gen_md[i]<=lambda*capacidad;
#envio[i]<=gen_md[i]<=lambda*capacidad;

subject to Restr{i in HORAS,s in ESCENARIOS}:
gen1[i,s]>=-0.8*gen_md[i];
```

```
subject to Restriccion2{i in VENTANA6, s in ESCENARIOS}:
g[i,s]<=gen_md[i]+gen1[i,s]+gen2[i,s]+gen3[i,s]+gen4[i,s]+gen5[i,s]+gen6[i,s]<
=lambda*capacidad ;

subject to Restriccion3{i in VENTANA5 diff VENTANA6,s in ESCENARIOS}:
g[i,s]<=gen_md[i]+gen1[i,s]+gen2[i,s]+gen3[i,s]+gen4[i,s]+gen5[i,s]<=lambda*ca
pacidad;

subject to Restriccion4{i in VENTANA4 diff VENTANA5,s in ESCENARIOS}:
g[i,s]<=gen_md[i]+gen1[i,s]+gen2[i,s]+gen3[i,s]+gen4[i,s]<=lambda*capacidad;


subject to Restriccion5{i in VENTANA3 diff VENTANA4,s in ESCENARIOS}:
g[i,s]<=gen_md[i]+gen1[i,s]+gen2[i,s]+gen3[i,s]<=lambda*capacidad;


subject to Restriccion6{i in HORAS diff VENTANA3,s in ESCENARIOS}:
g[i,s]<=gen_md[i]+gen1[i,s]+gen2[i,s]<=lambda*capacidad;



subject to Restriccion7{i in HORAS,s in ESCENARIOS}:
0<=gen_md[i]+gen1[i,s]<=lambda*capacidad;

subject to Restriccion8{i in HORAS,s in ESCENARIOS}:
0<=gen_md[i]+gen1[i,s]+gen2[i,s]<=lambda*capacidad;


subject to Restriccion9{i in VENTANA3,s in ESCENARIOS}:
0<=gen_md[i]+gen1[i,s]+gen2[i,s]+gen3[i,s]<=lambda*capacidad;

subject to Restriccion10{i in VENTANA4,s in ESCENARIOS}:
0<=gen_md[i]+gen1[i,s]+gen2[i,s]+gen3[i,s]+gen4[i,s]<=lambda*capacidad;


subject to Restriccion11{i in VENTANA5,s in ESCENARIOS}:
0<=gen_md[i]+gen1[i,s]+gen2[i,s]+gen3[i,s]+gen4[i,s]+gen5[i,s]<=lambda*capacid
ad;


subject to Restriccion12{i in VENTANA6,s in ESCENARIOS}:
0<=gen_md[i]+gen1[i,s]+gen2[i,s]+gen3[i,s]+gen4[i,s]+gen5[i,s]+gen6[i,s]<=lamb
da*capacidad;
```

Intradiario.dat

```
param precio_md:=

1      54.65
2      53.03
3      49.57
4      42.46
5      41.36
6      41.41
7      46.03
8      53.45
9      53.9
10     55.75
11     59.84
12     59.84
13     60.18
14     60.22
15     57.56
16     58.17
17     58.17
```

```
18      59.23
19      58.17
20      57.11
21      56.54
22      56.54
23      56.66
24      56.01;


param precio_int1:=

1       54.65
2       51
3       34.7
4       38.21
5       35.16
6       39.34
7       43
8       54
9       54.47
10      58.18
11      60.11
12      63.3
13      66.45
14      66.45
15      64.02
16      60.57
17      60.52
18      60.11
19      60.11
20      59.84
21      59.44
22      58.18
23      59.84
24      57.69;

param precio_int2:=

1       59.39
2       55
3       34.7
4       42.46
5       44
6       41.41
7       43.73
8       53.45
9       55.44
10      59.05
11      60.11
12      63.3
13      65.49
14      66
15      64.02
16      60.57
17      60.51
18      60.11
19      60.11
20      59.55
21      59.84
22      58.96
23      58
24      57.22;

param precio_int3:=

5       44.93
6       50.82
7       43
```

```
8       53.57
9       54
10      59
11      60.57
12      62.83
13      66.01
14      66.01
15      60.44
16      60.57
17      60.57
18      60.57
19      60.57
20      59.84
21      59.37
22      59.37
23      59.49
24      58.18;

param precio_int4:=

8       56.12
9       56.6
10      59.39
11      60.5
12      63.3
13      68.88
14      67.0
15      61.8
16      60.57
17      60.87
18      62.0
19      60.57
20      59.96
21      59.37
22      56.64
23      58.47
24      56.01;

param precio_int5:=

12      64.02
13      66
14      65
15      64
16      62
17      62
18      62
19      62.22
20      60
21      59.84
22      59.39
23      59.49
24      58.18;

param precio_int6:=

16      64.02
17      64.42
18      64
19      64.02
20      63.3
21      60.87
22      60.57
23      61.5
24      59.84;
```

```
param envio:=

1      4.4
2      4.0
3      3.7
4      3.6
5      3.5
6      3.6
7      3.7
8      3.8
9      3.9
10     8.4
11     8.6
12     8.8
13     9.0
14     9.0
15     9.1
16     9.0
17     8.9
18     8.9
19     9.0
20     9.2
21     9.2
22     8.6
23     7.9
24     7.3;

param lambda:=1;
param capacidad:=16.2;

param coste:=

1      54.65
2      53.03
3      50.21
.
.
.
62     0.5
63     0.8
64     -4.7;


param prob:=
1      0.045
2      0.075
3      0.01
.
.
.
.
62     0.02
63     0.005
64     0.01;
```

Appendix B

Documents .mod and .dat used to implement the second model with generation and intraday market price scenarios.

Intra2.mod

```
set HORAS:={1..24};
set VENTANA3:={5..24};#ventana intradiario 3
set VENTANA4:={8..24};#ventana intradiario 4
set VENTANA5:={12..24};#ventana intradiario 5
set VENTANA6:={16..24};#ventana intradiario 6
set ESCENARIOS:={1..64};#escenarios de generación
set PESC:={1..200}; #escenarios de precios

param precio_md {i in HORAS};
param precio_int1{t in PESC,i in HORAS};
param precio_int2{HORAS};
param precio_int3{VENTANA3};
param precio_int4{VENTANA4};
param precio_int5{VENTANA5};
param precio_int6{VENTANA6};
param coste {HORAS};
param envio {HORAS};
param error{s in ESCENARIOS};
param prob{s in ESCENARIOS};
param q{t in PESC}:=0.005;
param lambda;
param capacidad;
param g {i in HORAS, s in ESCENARIOS} := if envio[i] + error[s] > capacidad
then capacidad else envio[i] + error[s] ;

var gen_md{i in HORAS}>=0.9*envio[i];
var gen1{i in HORAS, s in ESCENARIOS, t in PESC}<= 0.6*capacidad, >= -
0.6*capacidad;
var gen2{i in HORAS, s in ESCENARIOS, t in PESC}<= 0.55*capacidad, >= -
0.55*capacidad;
var gen3{i in VENTANA3, s in ESCENARIOS, t in PESC}<= 0.5*capacidad, >= -
0.5*capacidad;
var gen4{i in VENTANA4, s in ESCENARIOS, t in PESC}<= 0.45*capacidad, >= -
0.45*capacidad;
var gen5{i in VENTANA5, s in ESCENARIOS, t in PESC}<= 0.4*capacidad, >= -
0.4*capacidad;
var gen6{i in VENTANA6, s in ESCENARIOS, t in PESC}<= 0.35*capacidad, >= -
0.35*capacidad;

maximize Profit:

sum{ i in HORAS}gen_md[i]*precio_md[i]
+sum{t in PESC}q[t]*(sum{s in ESCENARIOS}prob[s]*(sum{i in
HORAS}(gen1[i,s,t]*precio_int1[t,i] + gen2[i,s,t]*precio_int2[i])
+sum{i in VENTANA3}gen3[i,s,t]*precio_int3[i]
+sum{i in VENTANA4}gen4[i,s,t]*precio_int4[i]
+sum{i in VENTANA5}gen5[i,s,t]*precio_int5[i]
+sum{i in VENTANA6}gen6[i,s,t]*precio_int6[i]
-sum{i in
VENTANA6}coste[i]*(gen_md[i]+gen1[i,s,t]+gen2[i,s,t]+gen3[i,s,t]+gen4[i,s,t]+g
en5[i,s,t]+gen6[i,s,t]-g[i,s])
-sum{i in VENTANA5 diff
VENTANA6}coste[i]*(gen_md[i]+gen1[i,s,t]+gen2[i,s,t]+gen3[i,s,t]+gen4[i,s,t]+g
en5[i,s,t]-g[i,s])
-sum{i in VENTANA4 diff
VENTANA5}coste[i]*(gen_md[i]+gen1[i,s,t]+gen2[i,s,t]+gen3[i,s,t]+gen4[i,s,t]-
g[i,s])
-sum{i in VENTANA3 diff
VENTANA4}coste[i]*(gen_md[i]+gen1[i,s,t]+gen2[i,s,t]+gen3[i,s,t]-g[i,s])
```

```
-sum{i in HORAS diff VENTANA3}coste[i]*(gen_md[i]+gen1[i,s,t]+gen2[i,s,t]-
g[i,s])));

subject to Restriccion{i in HORAS}:#la programación en mercado diario tiene
que ser superior al envio y menor que el 80% de la capacidad
gen_md[i]<=lambda*capacidad;

subject to Restr{i in HORAS,s in ESCENARIOS, t in PESC}:
gen1[i,s,t]>=-0.8*gen_md[i];

subject to Restriccion2{i in VENTANA6, s in ESCENARIOS, t in PESC}:
g[i,s]<=gen_md[i]+gen1[i,s,t]+gen2[i,s,t]+gen3[i,s,t]+gen4[i,s,t]+gen5[i,s,t]+
gen6[i,s,t]<=lambda*capacidad ;

subject to Restriccion3{i in VENTANA5 diff VENTANA6,s in ESCENARIOS, t in
PESC}:
g[i,s]<=gen_md[i]+gen1[i,s,t]+gen2[i,s,t]+gen3[i,s,t]+gen4[i,s,t]+gen5[i,s,t]<
=lambda*capacidad;

subject to Restriccion4{i in VENTANA4 diff VENTANA5,s in ESCENARIOS, t in
PESC}:
g[i,s]<=gen_md[i]+gen1[i,s,t]+gen2[i,s,t]+gen3[i,s,t]+gen4[i,s,t]<=lambda*capa
cidad;


subject to Restriccion5{i in VENTANA3 diff VENTANA4,s in ESCENARIOS, t in
PESC}:
g[i,s]<=gen_md[i]+gen1[i,s,t]+gen2[i,s,t]+gen3[i,s,t]<=lambda*capacidad;


subject to Restriccion6{i in HORAS diff VENTANA3,s in ESCENARIOS, t in PESC}:
g[i,s]<=gen_md[i]+gen1[i,s,t]+gen2[i,s,t]<=lambda*capacidad;



subject to Restriccion7{i in HORAS,s in ESCENARIOS, t in PESC}:
0<=gen_md[i]+gen1[i,s,t]<=lambda*capacidad;

subject to Restriccion8{i in HORAS,s in ESCENARIOS, t in PESC}:
0<=gen_md[i]+gen1[i,s,t]+gen2[i,s,t]<=lambda*capacidad;


subject to Restriccion9{i in VENTANA3,s in ESCENARIOS, t in PESC}:
0<=gen_md[i]+gen1[i,s,t]+gen2[i,s,t]+gen3[i,s,t]<=lambda*capacidad;

subject to Restriccion10{i in VENTANA4,s in ESCENARIOS, t in PESC}:
0<=gen_md[i]+gen1[i,s,t]+gen2[i,s,t]+gen3[i,s,t]+gen4[i,s,t]<=lambda*capacidad
;


subject to Restriccion11{i in VENTANA5,s in ESCENARIOS, t in PESC}:
0<=gen_md[i]+gen1[i,s,t]+gen2[i,s,t]+gen3[i,s,t]+gen4[i,s,t]+gen5[i,s,t]<=lamb
da*capacidad;


subject to Restriccion12{i in VENTANA6,s in ESCENARIOS, t in PESC}:
0<=gen_md[i]+gen1[i,s,t]+gen2[i,s,t]+gen3[i,s,t]+gen4[i,s,t]+gen5[i,s,t]+gen6[
i,s,t]<=lambda*capacidad;
```

Intra2.dat;

```
param precio_md:=

1  36.53
2  28.00
3  10.07
4  10.00
5  10.07
6  10.07
7  37.43
8  48.97
9  46.20
10 49.10
11 48.51
12 48.00
13 48.51
14 47.51
15 46.27
16 48.27
17 48.27
18 49.51
19 50.27
20 52.01
21 57.21
22 57.12
23 52.57
24 49.10;

param precio_int1:

       1      2      3      4      ......       21     22     23     24:=

1      28.6   28.28  25.71  25.71  ......       25.71  27.88  27     35.64

2      29     27.88  25.28  22.1   ......       32.09  30.11  30     30.12

3      29     26.25  22.03  18.67  ......       43.25  39.5   41.95  43.95

.
.
.

197    47.43  43.51  49.48  47.43  ......       40.58  47.69  63     66.53

198    49.34  47.99  49.34  45.73  ......       55.1   54.6   54.6   56.55

199    52.92  46.87  43.87  42.88  ......       56.8   53.3   58.11  62.5

200    40     41     49.98  47.69  ......      53.8    43.55  62.35  61;

param precio_int2:=

1  7.31
2  5.00
3  0.00
4  0.00
5  0.00
6  5.00
7  10.00
8  48.97
9  49.85
10 48.73
11 48.51
12 47.53
13 47.79
14 47.51
15 46.27
16 48.27
```

```
17 48.27
18 48.59
19 47.87
20 46.81
21 54.21
22 50.09
23 44.68
24 41.60;

param precio_int3:=

5  0.00
6  3.02
7  11.23
8  48.97
9  47.44
10 49.11
11 48.68
12 47.53
13 48.51
14 47.54
15 46.00
16 48.27
17 48.00
18 49.00
19 49.27
20 46.81
21 54.35
22 51.00
23 45.21
24 41.74;

param precio_int4:=

8  48.97
9  46.34
10 49.10
11 48.51
12 48.00
13 48.54
14 47.54
15 46.30
16 48.30
17 48.28
18 49.51
19 50.27
20 46.81
21 54.21
22 51.00
23 45.21
24 44.00;

param precio_int5:=

12 40.00
13 45.00
14 40.38
15 39.33
16 48.76
17 48.27
18 49.51
19 49.27
20 46.81
21 54.21
22 52.84
23 47.31
24 44.19;
```

```
param precio_int6:=

16 42.27
17 33.79
18 34.66
19 35.19
20 26.01
21 50.92
22 50.84
23 46.79
24 44.44;

param envio:=

1      4.4
2      4.0
3      3.7
4      3.6
5      3.5
6      3.6
7      3.7
8      3.8
9      3.9
10     8.4
11     8.6
12     8.8
13     9.0
14     9.0
15     9.1
16     9.0
17     8.9
18     8.9
19     9.0
20     9.2
21     9.2
22     8.6
23     7.9
24     7.3;

param lambda:=1;
param capacidad:=16.2;

param coste:=

1  39.54
2  37.93
3  36.07
4  34.95
5  34.00
6  36.40
7  39.70
8  52.46
9  53.04
10 52.27
11 53.51
12 53.51
13 54.50
14 53.51
15 51.77
16 53.37
17 53.05
18 53.01
19 51.77
20 51.00
21 56.51
22 54.03
23 52.93
```

```
24 50.32;


param error:=
1      -0.1
2      0.1
3      2
.
.
.
62     0.5
63     0.8
64     -4.7;


param prob:=
1      0.045
2      0.075
3      0.01
.
.
.
62     0.02
63     0.005
64     0.01;
```

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