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The value of flexibility in energy markets

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The value of flexibility in electricity markets

University of Liège - Faculty of applied sciences

A dissertation submitted in partial fulfilment of the requirements for the degree of

Master in electrical engineer

by

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Academic year 2015-2016

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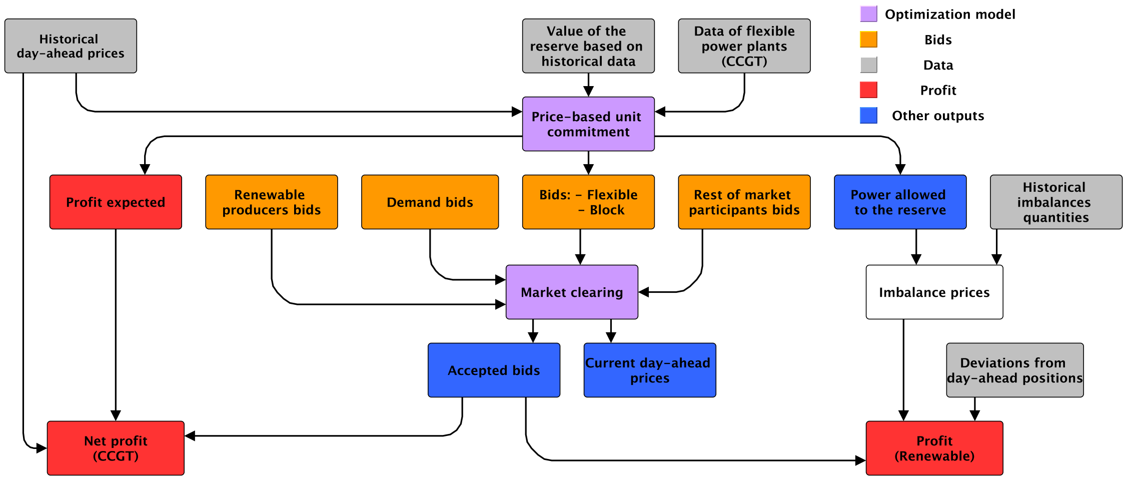
ABSTRACT - The value of flexibility in electricity markets

Danthine Alexandre

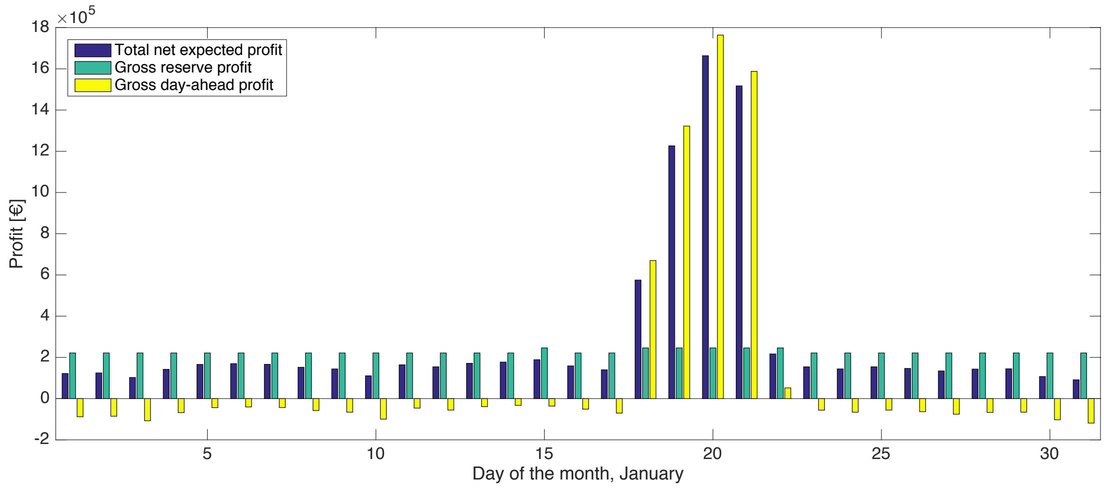
Section: Electricity, Electric power and energy systems **Academic year:** 2015-2016
Supervisor: Dr. Bertrand Cornélusse

The work presented in this master's thesis mainly focus on characteristics of flexible power plants. The power plants used are combined-cycle gas turbines. A review of the electrical system which focuses on the trading of electricity is presented. It gives order of magnitude on several data. This master's thesis designs a part of the electrical system focused on flexible power plants. First, a bidding strategy is modelled for a pool of power plants. The day-ahead market and the reserve market are considered taking into account all the constraints linked to these markets. A price-based unit commitment is used to model this bidding strategy. It is coded in Python with Pyomo. All the tests are made with Belgian January 2016 data. This mixed-integer programming model uses deterministic historical prices to determine if the power plants will run or not. This modelling is used to highlight the usefulness of such power plants in our electrical system. A small review of bidding strategy for renewable energy is also made. An estimation of their expected profits is calculated. The power generated in the price-based unit commitment is converted into different bids to make a market clearing with them. A validation of this bidding strategy is performed by modelling all the markets participants to make a market clearing. To validate the previous model the acceptance of the bids created by the PBUC are checked. This master's thesis gives an overview of the electricity market jungle.

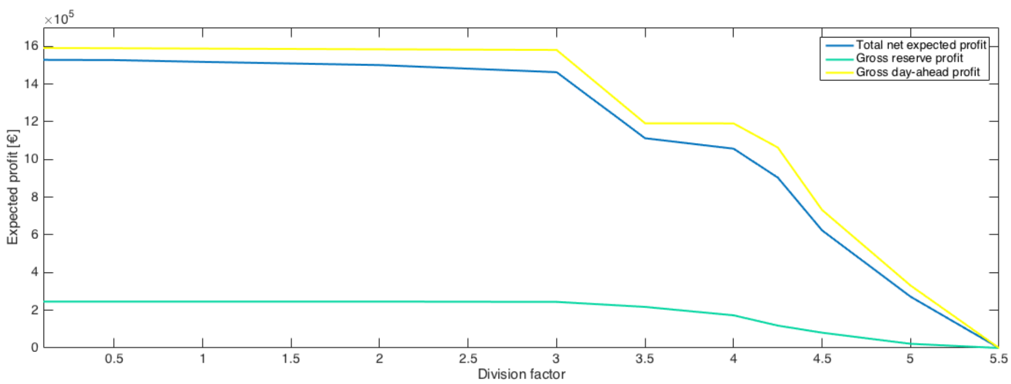
Significant figures of this master's thesis



Global model of the electrical system



Expected profit of the PBUC of the entire pool of CCGTs, January 2016



Variation of profit compared to a change of ramp rate of all the power plant pool

Chapter 1

Introduction

1.1 Context

Nowadays, the part taken by the renewable energy never stops growing. This kind of power plants increases the uncertainty of production which leads to a more risky power system. To encounter this phenomena, many precautions are taken to ensure the stability of the system (storage, load management, flexible power plant,...). The precaution that we will consider in detail in this master's thesis is the flexible power plant. As the part of the renewable takes more and more importance in the market, we must maximize the bidding strategy of these flexible power plants which have a high production cost. The bidding part for a GenCo can be really tricky due to the different kind of bid that the market can handle and the number of available markets.

The goals of this master's thesis are to optimize the way of bidding in different markets with different kinds of assets available, to quantify the added value by the flexibility of these power plants and validate the model created.

1.2 The electrical system

1.2.1 Introduction

The electrical system is something really complicated and constantly changing. Decades ago, the electrical market was reformed which allowed competition in the market. This new way of trading electricity needed regulation operator to keep the system function.

The electricity is a commodity extremely hard to exchange as the consumption must be kept equals to the production at any time. To keep this constraint satisfied, a lot of interactions between the different participants must be done.

1.2.2 Principal participants of the system

The main role of the electrical system is to ensure a safe and reliable trade between the *consumers* and the *producers*. The producers are also called generation company (GenCo). The small consumers as the private consumer do not trade their personal electricity. They use the services of a *retailer* which will trade large amount of energy to provide a lot of small consumers. He acts like a wholesaler in the electricity market.

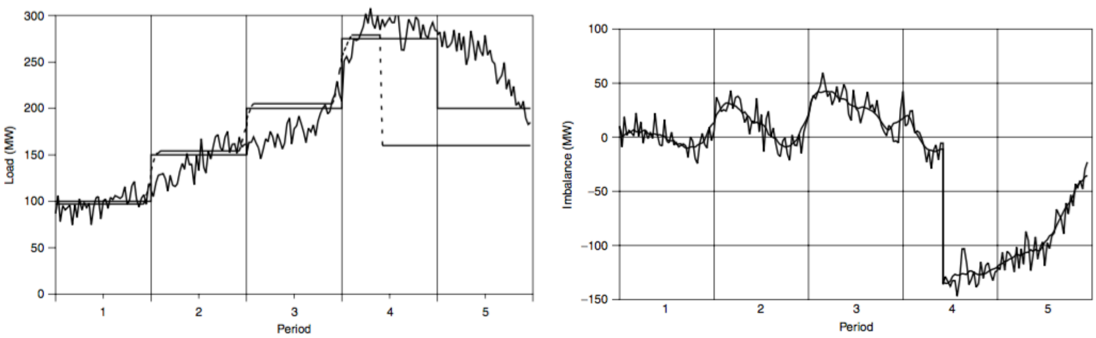
To trade the electricity, we need to have a safe and reliable mode of transportation. The network used includes the whole physical system to transport electricity which includes the lines and cables but also all the devices important for the safety of this network. The safety and the reliability of the network are ensured by two operators as the network is divided by the voltage of the network.

- The distribution system operator (DSO) which takes care of the distribution network which encompasses the low voltage ($\leq$ 1kV) and the medium voltage (1kV - 36kV). Its role is to maintain the security of power system operation, facilitate the retail market and collect the metering of the electricity customers.
- The transmission system operator (TSO) which takes care of the high voltage transmission network ($\geq$ 36kV). Its principal role is to maintain the balance at every moment between the production and the consumption.

This constraint of keeping the balance is first ensured by the planning of the consumption and production on a quarterly time step for all the day asked by the TSO. These data are provided by the balance responsible parties (BRP) which regroup producers, consumers and retailers. This planning is called the baseline.

1.2.3 Imbalance

The real realization often deviates from the baseline and the difference is called the imbalance (cf. Figure 1.1). The TSO has the responsibility to compensate this imbalance.



(a) Typical load and generation fluctuations over five market periods

(b) Imbalances resulting from these fluctuations

Figure 1.1: Example to highlight the imbalance [15]

State of the system

The system can be in three different states regarding the imbalances of the system:

- **Up-regulation:** The system is in deficit of power production as a result of all deviations from producers and consumers with respect to their previous positions.

- **Down-regulation:** The system has a surplus of power production as a result of all deviations from producers and consumers with respect to their previous positions.
- **No-regulation:** The difference between the production and the consumption of the system is zero.

The last state happens only punctually (cf. Figure 1.1(b)) as the system always needs some small adjustments.

Reserve

To ensure this equality, different mechanisms as presented below are available for the TSO:

1. **Frequency Containment Reserves (FCR)**: It is the primary reserve which is used to respond to transient disturbances on the frequency of the system. This control is really quick as it works within 30 seconds.
2. **Automatic Frequency Restoration Reserve (aFRR)**: It is the secondary reserve[1] which is used to replace the primary reserve and bring back the system to his set point. It is done automatically and within 5 minutes.
3. **Manual Frequency Restoration Reserve (mFRR)**: It is the tertiary reserve and is similar to the secondary reserve but it is manual and must be done within 15 minutes.

As the electrical system is unbundled, the TSO does not own these generation units which provide these ancillary services. A market is dedicated to the trading of these ancillary services. These markets are presented below.

1.2.4 Trading electricity

Due to the liberalization, a whole new way of trading the electricity appears. It allows the seller to consider more opportunity than he had in the past.

An essential part of the job of the GenCo is to sell their power at the right price and in the right market. The electricity is traded before its delivery. Some ways of trading electricity are introduced here:

1. **Market pool (PoolCo)**: It is a centralized marketplace where the independent system operator (ISO)[2] cleans the market according to the sellers' and buyers' bids. GenCo do not compete for specific customers but for the right to supply energy to the grid.
2. **Bilateral contract (BC) market**: This way of selling power is used in flexible market where the participants can specify and negotiate the terms and conditions of trading agreements independent from the ISO. The ISO still ensures the transmission capacity and security.
3. **Hybrid market (HM)**: It contains either PoolCos and BC but also ancillary services. We can see a typical structure of hybrid market in Figure 1.2.

[1] Also called Automatic generation control (AGC)

[2] This ISO can also be called market operator (MO).

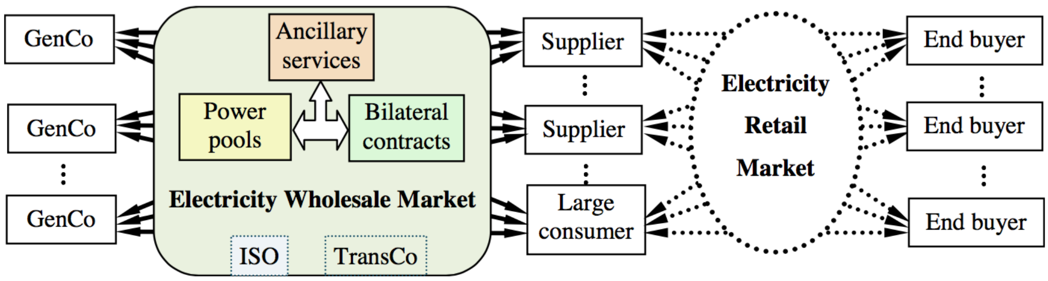


Figure 1.2: Typical hybrid market structure [16]

The bilateral contract is mostly used in long term contract. Just like that a big company can assure its supply on a long term with a GenCo to provide its minimum energy needs. This ensures the company to be independent of the fluctuation of the price on the market and avoid the risk of a possible non-profitable production.

The following presentation of the electrical market system is a global view of it. In fact, it changes a lot throughout the different countries with different markets or time division during the day.

The most common pool market introduces for short-term trading is the *day-ahead market*. Day-ahead electricity markets are designed as two-sided auctions where the participants submit orders to buy or sell electricity for some time steps of the next day. (*In Belgium*, the day is separated in time step of fifteen minutes). The orders are submitted with a set of price and quantity to the market operator. This set indicates the amount of power the participants want to buy or sell and at which maximum or minimum price. The Figure 1.3 shows the way the market is cleared. The market operator constructs an aggregate curve of demand and supply.

The Market Clearing Price (MCP) is determined by the intersection between these two curves (cf. Figure 1.3). Their bids are rewarded if they are accepted by the market clearing. The MCP is associated with a quantity of energy. Every bid to the left of this quantity is accepted.

In PoolCos, the price can be settled in two ways:

1. **Uniform price (UP) auction**: The price is settled at the MCP. So the buyers and the sellers will have the same reward price. This method invites the participants to bid at their marginal costs and discourage gaming on the price.

2. **Pay-as-bid (PAB) auction**: The reward price is settle at the participant order price. It is expected to lower the market price and reduce the price volatility.

The auctions can also be separated in two types :

1. **Static auctions**: The bids are sealed once submitted.

2. **Dynamic auctions**: The bids can be sequentially reevaluated.

The day-ahead market deal with uniform price and static auction. The day-ahead energy market of a lot of European country are grouped together. The market clearing process used for this day-ahead market is called Euphemia [9].

Different kind of bids can be ordered in this market as piecewise linear bid curve or step bid. These two different bids can be specified in three different types of bid used in this work:

1. **Flexible bid**: A certain amount of power is bidden on the market and any amount of power of the bid below the power of the bid can be accepted.
2. **Block bid**: Different amount of power are bidden at different time steps. They are considered as a block. This block can be bought totally or not be bought at all. These block follows the rule "Fill or kill".
3. **Exclusive bid**: The exclusive bids can be either block or flexible bids. The particularity of them is that only one bid can be picked from a group of exclusive bids.

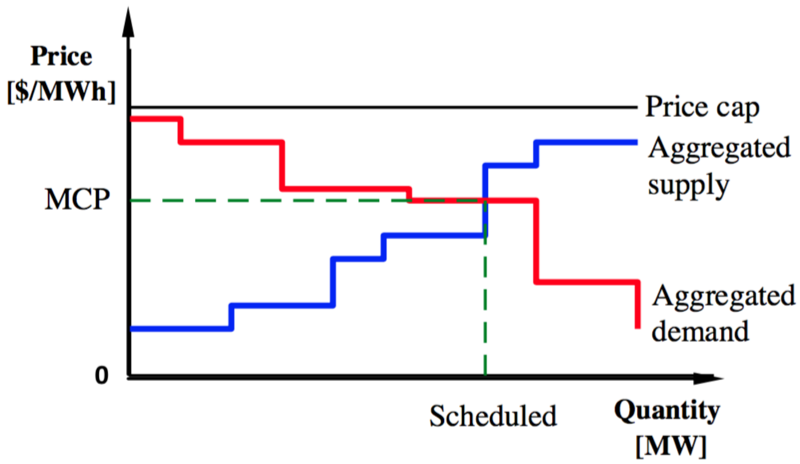


Figure 1.3: Example of market clearing [16]

The *day-ahead market* is the principal way of trading electricity. However, other markets close to the real time exists which are called *intra-day markets*. These markets take more and more importance as the part of renewable energy never stop growing. It can be understood as the renewable producers must adjust their productions as we get closer to the real-time.

The *reserve market* is a market where the sellers could bid a capacity of reserve which can be activated by the ISO to regulate the system. They offer capacity with a price expressed in €/Mwh/h. It is a reservation price which is paid even if the capacity is not used. Furthermore, the energy provided is remunerated at the marginal cost of the power plant as a pay-as-bid auction.

At last, the *balancing market* is the last market which will ensure the link between the production and the consumption. It is also called the *real-time market*. This market regulates at last the imbalances of electricity in the system.

Two different types of balancing market exist:

- **One-price balancing market**: The deviations from the day-ahead position are traded at the same price no matter the imbalance sign.
- **Two-price balancing market**: The deviations from the day-ahead market position traded differently regards the imbalance sign. On the one hand, deviations which

are in the opposite sign of the imbalance are sold at the day-ahead price (ρ^D). On the other hand, deviations which are in the same direction are sold at the balancing price (ρ^B). These two balancing prices (ρ^{UP} and ρ^{DW}) are defined in (1.1) and (1.2).

$$\rho^{UP} = \begin{cases} \rho^B & \text{if} \quad \rho^B \geq \rho^D \\ \rho^D & \text{if} \quad \rho^B < \rho^D \end{cases} \tag{1.1}$$

$$\rho^{DW} = \begin{cases} \rho^D & \text{if} \quad \rho^B \geq \rho^D \\ \rho^B & \text{if} \quad \rho^B < \rho^D \end{cases} \tag{1.2}$$

On the one hand, if the Net Regulation Volume[3] is positive i.e. the system is in up-regulation, the *balancing price* is settled to the marginal price of the most expensive power plant paid by the TSO to fulfil the lack of power of the system at this time step. On the other hand, if the Net Regulation Volume is negative i.e. the system is in down-regulation, the *balancing price* is settled to the marginal price of the less expensive power plant received by the TSO to fulfil the excess of power of the system at this time step.

In Belgium, it is a one-price balancing market with a little subtlety. On the Elia website [6], two prices are mentioned but they have nothing in common with a two-price balancing market as those prices do not deal with the day-ahead prices. The two prices are most of the time the same but some small differences imposed by the TSO can appear.

1.3 What is flexibility ?

In this master's thesis, we will focus on the flexibility brought by some kind of power plant. This flexibility will be defined by the characteristics of these power plants as the ramp up and ramp down limits as well as the minimum up and minimum down time.

1.4 Literature review of bidding strategy

An important challenge of this master's thesis is to find an efficient way of bidding energy in different markets. Many studies have been done on the way of bidding electricity depending of the different markets and on the type of assets considered.

A good way to start was to find a review of all these bidding strategies. In [16], we can find more than 130 publications on that theme and this article made a good state-of-start review of all types of bidding strategy existing in liberalized market. It is a good way to start as it explains well the different characteristics on market and how they work.

In [11], the authors consider Nordic hydro-power producers. These assets can be compared with the one considered in this work as they can be turn on or off in a really flexible way. They bid on a day-ahead market and they try to know if the add of an intra-day market could increase the benefit of the producers. They do a two-stage mixed integer stochastic program with a stage per market. They conclude that the addition of such a market does not increase the profit of the hydro-power producers.

[3]Net Regulation Volume (NRV) is the difference between the up regulation volume and the down regulation volume.

In [2], the authors consider a day-ahead and an hour-ahead balancing market for the Nordic markets. They do a multi-stage stochastic program where the stages set the bid and the imbalances. The goal is to quantify the gain of coordinated bidding. They show that there is no incentive to go in the balancing market with a one-price balancing market unlike a two-price market and the coordinate bidding increases the profit.

In [4], the authors consider MIBEL[4] through different mechanisms: the bilateral contracts, the physical derivatives, the day-ahead market, the intra-day market and the ancillary service market. In the reserve market, the power plants can just bid or not their AGC capability. For the future contracts, the producers define the term of the contract. Afterwards, the GenCo receives what they will produce and they bid their productions to an instrumental price (0€/MWh) to the day-ahead market. For the bilateral contracts, the terms of the contract are negotiated before the day-ahead market and the energy of the bilateral contract is excluded from the day-ahead market. The authors use multi-stage stochastic programming with three market prices, based on historical prices.

In [21], the authors consider thermal power plant with day-ahead market, reserve market for AGC and balancing market.

After reviewing different bidding strategies, I noticed that nearly all the work done on that subject uses stochastic programming. This way of programming is not something that I had the opportunity to use during my years of study. So, I decided not to use this kind of programming in my model.

The model used in this master's thesis consists in a price-based unit commitment (PBUC) and afterwards divide this possibly generated electricity in different bids.
In [3], the authors present a PBUC which allows the power plant to have a piece-wise linear cost curve. This behaviour is used in the model presented in this master's thesis.
In [17], the authors present a PBUC with easy to implement and to solve up time and down time constraints which are used in my model.
In [20], a simple way to create bids for different types of assets is introduced. The PBUC considered in this work has the possibility of bidding in the secondary reserve market. This way of bidding this reserve is a melt of all the model reviewed previously.

A new formulation for European day-ahead market clearing is introduced in [18]. This presented formulation avoids the use of complementary constraints to express market equilibrium conditions, and also avoids the introduction of auxiliary continuous or binary variables, when the model uses blocks bids. The authors rely on strong duality theory for linear or convex quadratic optimization problems to recover equilibrium constraints. The model introduced in this paper is the one used in this work.

The literature review on bidding strategy shows that it is really hard to find and to do a general model which encompass all the possibilities of trading. First, such a model is really hard to model and to solve. Then, the difficulty of picking up the right markets to bid results in the large amount of different configurations of electricity market system all over the world. Even in Europe, we can find several different markets as we saw in the previous papers. It is hard to be sure on the way all these markets work together and on the way the producers bid their electricity as it is something they do not obviously reveal.

[4]Iberian Electricity Market

1.5 Global model introduced in this master's thesis

The literature read and the knowledge acquired to write this overview of the electrical system leads to the construction of a simplified model for this electrical system. Indeed, to see the impact of the flexibility on the profit of these power plants, a more global model for the electrical system than a price-based unit commitment needs to be defined.

Overview of the model:
The simulation of the electrical system shall take place in a few steps :

1. Prediction of the price.
2. Unit commitment to maximize the GenCo's profit : Price-based unit commitment(PBUC)[5].
3. Convert the expected power generated, thanks to the PBUC, in different kinds of bid for the day-ahead auction.
4. Perform a market clearing for the day-ahead market with the bids of the PBUC and those of other market participants.
5. Settlement of the profit.

An overview of the electrical system as it is modelled in this master's thesis is presented in the Figure 1.4.

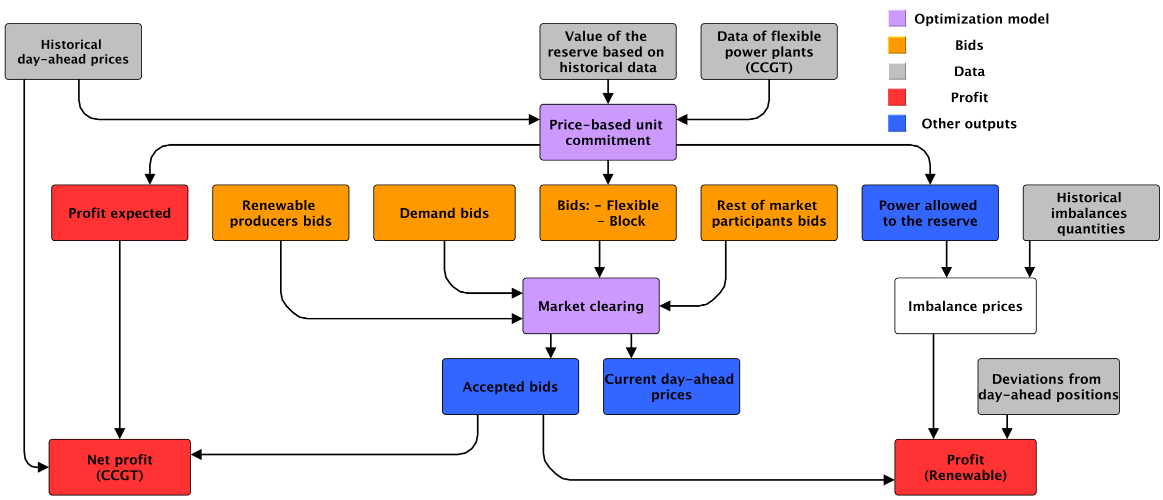


Figure 1.4: Global model of the electrical system

1.6 Structure of the master's thesis

The modelling of the entire electrical system is quite complex and implies lots of participants and lots of interactions. In this master's thesis, the different chapters explain separately each part of this system.
First, the Chapter 2 explains how the bidding strategy for flexible power plant is modelled with the details of the PBUC and the settlement of the imbalance price. The model

[5]It maximizes the profit taking the price.

shows its global behaviour with different price signals. The profit withdrawn from this model is estimated. Lots of tests are performed on this model to highlight the relevance of flexibility of these power plants.
Then, the CHAPTER 3 introduces the renewable producers with some data and with a bidding strategy. An estimation of the profit made by the renewable producers in Belgium is also performed.
The CHAPTER 4 is focused on the market clearing and mainly on how the bids are created from the PBUC to the market clearing.
At last, the CHAPTER 5 groups all the part of the system to evaluate the relevance of the bidding strategy introduced in the CHAPTER 2.

Chapter 2

Flexible power plant modelling

2.1 Introduction

This chapter will focus on the modelling, the characteristics, the expected profit and the relevance of these flexible power plants.

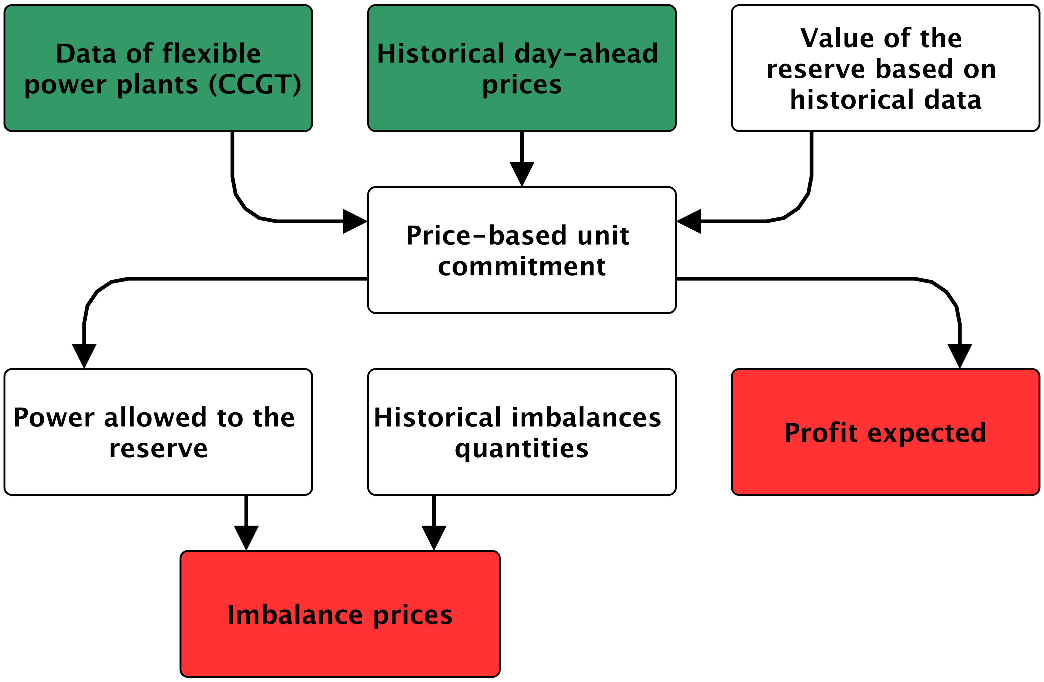


Figure 2.1: Reduced model which encompass flexible assets

In Figure 2.1, the modelling of these combined cycle gas turbines (CCGT) is showed. Green data are those on which a sensitivity analysis is performed. Red data are the output of this model.

Combined-cycle gas turbines (CCGTs) are used because their are the most common flexible power plants in the market. It is a power plant which combine gas turbine and steam power plant. These power plants are characterized by their really high ramp rate. It is between 10 MW/min and 100 MW/min which can be really useful in a large-scale implementation of renewable as it can compensate the fluctuation of the renewable during the day. The principal drawback of this kind of power plant is its costs which can often be a lot higher than the day-ahead prices. This leads to be very often out of money.

2.2 Explanation of the model

A large pool of CCGTs is considered to be bid in the different markets (day-ahead and reserve market). The model is centralized on the producer. Data used to modelize the pool are from Engie. In this model, the prediction of the day-ahead and reserve price are based on deterministic historical prices. The producers are price-takers, i.e. they do not influence the market prices with their bidding strategies.

2.2.1 Price-based unit commitment (PBUC)

The PBUC takes into account the day-ahead market and the reserve market. Only the reserve market for the secondary reserve (AGC) is considered. This model was mostly inspired by [5], [17] and [3]. The model is implemented in Pyomo [12][13].

First, the model is presented without the reserve market in order not to confuse the reader. It will be added afterwards.

Basic model with day-ahead market

The constraints and variables are defined for each generation units $i \in \{1, ..., N_g\}$ and each time step $t \in \{1, .., T\}$ where N_g is the total number of generation units and T is the number of time step considered.

The variable costs will be modelled with a piecewise linear function of maximum three slopes which is often the case in a lot of paper. These slopes will be characterized by the set $l \in \{1, ..., 3\}$.

Nomenclature:

`Variables:`

- $s_{i,t} \in \mathbb{B}$ is the on/off decision for the thermal unit i in period t,
- $p_{i,t} \in \mathbb{R}_+$ is the power generated by the unit i in period t,
- $s_{i,t}^{up} \in \mathbb{B}$ indicates if the unit i starts up or not between time $t-1$ and t,
- $s_{i,t}^{down} \in \mathbb{B}$ indicates if the unit i shut down or not between time $t-1$ and t,
- $\delta_{i,t,l} \in \mathbb{R}_+$ is the power produced in block l of the piecewise linear cost function of unit i in period t.

`Constants:`

- $\rho_t^D \in \mathbb{R}_+$ is the prediction for the day-ahead market price at time t,
- $C_i^{fixed} \in \mathbb{R}_+$ is the fixed running cost of the thermal unit i,
- $C_{i,l}^{prop} \in \mathbb{R}_+$ is the variable cost of the thermal unit i of block l of the piecewise linear cost function,
- $C_i^{up} \in \mathbb{R}_+$ is the start up cost of the thermal unit i,
- D_t is the time scaling factor as the costs are defined in hour which is not often the time step used,
- $P_i^{min} \in \mathbb{R}_+$ is the minimal power allowed by the unit i,
- $P_i^{max} \in \mathbb{R}_+$ is the maximal power allowed by the unit i,
- ΔP_i^{up} is the maximum ramp up limit by the unit i,
- ΔP_i^{down} is the maximum ramp down limit by the unit i,
- P_i^{init} is the power produced by the unit i at the iteration just before the starting point of the model,
- $D_i^{min,up}$ is the minimum up time of the unit i,
- $D_i^{min,down}$ is the minimum down time of the unit i,
- U_i^{init} is a binary data which shows if the unit i was on or off at the initial time,
- D_i^{init} is the number of time interval that the unit i was in the on or off status,
- $T_i^{init,up}$ is the number of time interval the unit i needs to remain on if on at the beginning of the scheduling period,
- $T_i^{init,down}$ is the number of time interval the unit i needs to remain off if off at the beginning of the scheduling period,
- $B_{i,l}$ is the upper limit of block l of the piecewise linear production cost function of unit j.

`Objective:`

The objective function consists in maximizing the difference between the profit earned by selling the electricity and the production cost. This cost is separated in three, the fixed cost, the variable cost and the start-up cost.

$$\begin{aligned} \max \sum_{t=1}^{T} \Bigg(\sum_{i=1}^{N_g} \Bigg(& D_t \rho_t^D \, p_{i,t} \\ & - \left(D_t C_i^{fixed} s_{i,t} + D_t \left(C_{i,1}^{prop} P_i^{min} s_{i,t} + \sum_{l=1}^{3} C_{i,l}^{prop} \delta_{i,t,l} \right) + C_i^{up} s_{i,t}^{up} \right) \Bigg) \Bigg) \end{aligned} \tag{2.1}$$

`Constraints:`

The generation unit must stay in acceptable range of power:

$$s_{i,t}P_i^{min} \leq p_{i,t} \leq s_{i,t}P_i^{max} \tag{2.2}$$

An initial value must be imposed for the power produced and the on/off status of the generators to know their values just before the scheduling period:

$$p_{i,0} = P_i^{init} \tag{2.3}$$
$$s_{i,0} = U_i^{init} \tag{2.4}$$

Constraints on the ramping rates need to be imposed:

$$p_{i,t} - p_{i,t-1} \leq \Delta P_i^{up} \tag{2.5}$$
$$p_{i,t-1} - p_{i,t} \leq \Delta P_i^{down} \tag{2.6}$$

The values of the start-up and the shut-down indicators need to be settled. The following equation enforces the time step relationship among unit status, start-up and shut-down indicators,

$$s_{i,t}^{up} - s_{i,t}^{down} = s_{i,t} - s_{i,t-1} \tag{2.7}$$

Since a unit may not be started up and shut down simultaneously at a given time step, this leads to the following equation,

$$s_{i,t}^{up} + s_{i,t}^{down} \leq 1 \tag{2.8}$$

To create the minimum up time constraint, the number of time interval a unit needs to remain on at the beginning of the scheduling period must be defined,

$$T_i^{init,up} = \max\left\{0, \min\left[T, \left(D_i^{min,up} - D_i^{init}\right) s_{i,0}\right]\right\} \tag{2.9}$$

Two cases are needed for the minimum up time constraints,

- at the beginning of the scheduling period

$$\sum_{t=1}^{T_i^{init,up}} (1 - s_{i,t}) = 0 \tag{2.10}$$

- at any time except the beginning

$$\forall t = (T_i^{init,up} + 1), ..., T \quad : \tag{2.11}$$
$$s_{i,t}^{up} + \sum_{m=t+1}^{\min\{T, t+D_i^{min,up}-1\}} s_{i,t}^{down} \leq 1 \tag{2.12}$$

To create the minimum down time constraint, the number of time interval a unit needs to remain off at the beginning of the scheduling period must be defined,

$$T_i^{init,down} = \max\left\{0, \min\left[T, \left(D_i^{min,down} - D_i^{init}\right)(1 - s_{i,0})\right]\right\} \tag{2.13}$$

Two cases are needed for the minimum down time constraints,

- at the beginning of the scheduling period

$$\sum_{t=1}^{T_i^{init,down}} s_{i,t} = 0 \tag{2.14}$$

- at any time except the beginning

$$\forall t = (T_i^{init,down} + 1), ..., T \quad : \tag{2.15}$$

$$s_{i,t}^{down} + \sum_{m=t+1}^{\min\{T,t+D_i^{min,down}-1\}} s_{i,t}^{up} \leq 1 \tag{2.16}$$

The following constraints allow to have a piecewise linear cost function,

$$p_{i,t} = \sum_{l=1}^{3} \delta_{i,t,l} + P_i^{min} s_{i,t} \tag{2.17}$$

$$\delta_{i,t,1} \leq B_{i,1} - P_i^{min} \tag{2.18}$$

$$\delta_{i,t,2} \leq B_{i,2} - B_{i,1} \tag{2.19}$$

$$\delta_{i,t,3} \leq P_i^{max} - B_{i,2} \tag{2.20}$$

Addition of the reserve market

The reserve market included in the model tries to mimic the behaviour of the one of ELIA which could be found in [7]. The following model does not tend to be an exact replica of the one existing in Belgium but a good way to estimate the possible gain that an electricity producer can withdraw from that market.
The main differences compared to the representation of ELIA are :

- The capacity is automatically accepted while the TSO must do a selection of the capacity offers.
- The power plants can provide the capacity they afford. The power plant can not be penalized because they deviate too much from the capacity provided.
- For the activation remuneration, the power plants are remunerated at their marginal costs which is a bit trickier in reality.

Nomenclature:

`Variables added:`

- $w_{i,t} \in \mathbb{B}$ indicates if the unit i is engaged in AGC at time t,
- $w_{i,t}^{up} \in \mathbb{B}$ indicates if the unit i is engaged in AGC for up-regulation at time t,
- $w_{i,t}^{down} \in \mathbb{B}$ indicates if the unit i is engaged in AGC for down-regulation at time t,
- $g_{i,t}^{up} \in \mathbb{R}_+$ is the reserve allocated to the reserve market for an up-regulation for the unit i at time t,
- $g_{i,t}^{down} \in \mathbb{R}_+$ is the reserve allocated to the reserve market for an down-regulation for the unit i at time t.

`Constants added:`

- $\rho_t^{R,up} \in \mathbb{R}_+$ is the price for the up-regulation at time t,
- $\rho_t^{R,down} \in \mathbb{R}_+$ is the price for the down-regulation at time t,
- $G^{max} \in \mathbb{R}_+$ is the maximum capacity requested by the ISO to the reserve market for the up or down-regulation[1].

`Constraints added:`

Some constraints need to be redefined to add the reserve market.

First, the equation (2.2) is changed to include the reserve allocation in the admissible range of the power produced,

$$s_{i,t}P_i^{min} + g_i^{down}w_{i,t}^{down} \leq p_{i,t} \leq s_{i,t}P_i^{max} - g_i^{up}w_{i,t}^{up} \tag{2.21}$$

The power plant must be on when it provides reserve. In fact, the activation power needed could bring the power plant into a forbidden zone of the power plant if this one is not switched on. This constraint is represented by the equations (2.22) and (2.23).

$$s_{i,t} \geq w_{i,t}^{up} \tag{2.22}$$
$$s_{i,t} \geq w_{i,t}^{down} \tag{2.23}$$

The variable that indicates if the unit is engaged in AGC must be 1 if this unit is engaged in up or down-regulation,

$$w_{i,t} \geq w_{i,t}^{up} \tag{2.24}$$
$$w_{i,t} \geq w_{i,t}^{down} \tag{2.25}$$

Then, the equations (2.5) and (2.6) are changed. The following equations forbid to ramp up or down if a power plant is engaged in AGC as their controls are transferred to the ISO [4][21],

$$p_{i,t} - p_{i,t-1} \leq \Delta P_i^{up}(1 - w_{i,t}) \tag{2.26}$$
$$p_{i,t-1} - p_{i,t} \leq \Delta P_i^{down}(1 - w_{i,t}) \tag{2.27}$$

[1] In Belgium, the capacity allocated for the up and down-regulation is the same. (140 MW)

The GenCo can bid a part of his capacity in the reserve market. The reserve capacity is limited to a maximal capacity as it is expressed in the equations (2.28) and (2.29). The value of G^{max} can be settled to the maximum capacity that the ISO requests if the pool bid is big enough to handle it. Otherwise, a smaller value is taken if the pool can not handle all the capacity requests by the ISO.

The total power allocated to the AGC must stay in a limited range,

$$\sum_{i=1}^{N_g} g_{i,t}^{up} \leq G^{max} \tag{2.28}$$

$$\sum_{i=1}^{N_g} g_{i,t}^{down} \leq G^{max} \tag{2.29}$$

These limits on the reserve capacity were created because the remuneration of this provided capacity is quite high. So, the producers could bid most of the time their entire production. As all the capacities provided are accepted in this model, a huge error could be made without these constraints. Indeed, if a reserve market clearing is considered, lots of bids will not be accepted. So, without these constraints, the profit of the GenCo will constantly be overestimated.

The constraints (2.30) and (2.31) allow capacity reserve only if the unit is engaged in AGC. The big-M formulation is used in these equations ($G^{max} = M$).

$$G^{max} w_{i,t}^{up} \geq g_{i,t}^{up} \tag{2.30}$$

$$G^{max} w_{i,t}^{down} \geq g_{i,t}^{down} \tag{2.31}$$

To be accepted in the secondary reserve market, the supplier must be able to provide the total selected volume, in the upwards or downwards direction, in 7.5 minutes. In fact, the ramp rates are in [MW/h] so we need to convert these in minutes. These two facts lead to these equations (2.32) and (2.33),

$$\Delta P_i^{up} \geq g_i^{up} \times 8 \tag{2.32}$$

$$\Delta P_i^{down} \geq g_i^{down} \times 8 \tag{2.33}$$

As it is yearly reservation, the capacity bid in the reserve must be the same for all the day,

$$\forall t \in 2, .., T-1 :$$

$$\sum_{i=1}^{N_g} g_{i,t}^{up} = \sum_{i=1}^{N_g} g_{i,t+1}^{up} \tag{2.34}$$

$$\sum_{i=1}^{N_g} g_{i,t}^{down} = \sum_{i=1}^{N_g} g_{i,t+1}^{down} \tag{2.35}$$

The time index of the equations (2.34) and (2.35) starts at the second time step. This limitation is due to the constraint that forces the power plant to be switched on to bid in the reserve market.

The deviation of supplied reserves compared to the signal sent by the TSO, should be smaller than 15% of the selected volume at all time. To encounter this constraint, each power plant can not bid too small quantities. Indeed, the power plants do not have an infinite accuracy on their output power. The capacity bids in the reserve is 1 MW per procurement period per power plant. This constraint also fixes the minimal ramp rate to 60 MW/h to enter in the reserve market. Another cause of taking 1 MW as minimal quantity is the minimal resolution of 1 MW for the activation signals given by ENTSOE [8].

To ensure that the minimal capacity bid in the reserve market for each power plant is 1 MW[2],

$$w_{i,t}^{up} \times 1 \leq g_{i,t}^{up} \tag{2.36}$$

$$w_{i,t}^{down} \times 1 \leq g_{i,t}^{down} \tag{2.37}$$

`Objective:`

For the activation price, the generation or the non-generation are compensated at the marginal price of the power plants (pay-as-bid auction). The producer is paid or must paid depending if it is up or down-regulation.
For the reservation price, the price paid by the TSO per procurement period can be found on the ENTSOE website [8].

The objective function is updated by adding the term $D_t\,(\rho_t^{R,up}\, g_{i,t}^{up} + \rho_t^{R,down}\, g_{i,t}^{down})$ in the income of the objective function. The prices of reservation for up and down-regulation are equals in Belgium ($\rho_t^{R,up} = \rho_t^{R,down}$).

2.2.2 Settlement of the imbalance price

The settlement of the imbalance price is defined in Section 1.2.4.

First, the net regulation volume (NRV) is defined with historical data of activation of up and down regulation. It is the difference between the up-regulation activated and the down-regulation activated.

To know what is the higher/lower marginal cost paid/received by the TSO, a ranking of the power plants that have bidden in the reserve market is done. Then, if the NRV is positive/negative, the higher/lower marginal cost of power plants used to fulfil the up/down-activation is taken as the imbalance price.

2.3 Numerical examples

The model presented in the previous section has been tested with real CCGT data of Engie and can be found in the Appendix A. The pool of power plants represents a total capacity of 4527.3 MW and is composed of CCGTs only. The Entsoe data are used for the reserve price [8]. We take data from January 2016 for our tests. In Figure 2.2, the data prices used for the day-ahead market are represented [1].
The reservation price is equal to **37 €**/MW/h in up or down-regulation in January 2016.

[2]The use of semi-continuous variable is not allowed in PYOMO

This reservation price ranges between 30.76 and 77.92 €/MW/h since January 2015 and the mean of this price is 45.05 €/MW/h. So, the profit earned by the reserve can be a lot higher in other months.
For most tests, the model is computed with the maximal reserve capacity (G^{max} = 140MW) as we consider the pool of CCGTs large enough to handle the total reserve capacity.

Thursday, January 21, 2016	
CPU time (s)	135
Absolute gap (Euro)	151.72
Relative gap (%)	0.01

Table 2.1: Solution time and quality

The number of constraints, real variables, and binary variables in the resulting problem are respectively, 19056, 7434 and 6204. It has been solved using GUROBI under PYOMO. The computational characteristics of the solution are illustrated in Table 2.1. The computer used was a MacBook Pro with one processor at 2.3 GHz and 8 Gb of RAM memory. This particular case of the problem converges quite fast compared to other cases which can take hours. This phenomena was highlighted when the ramp rates were reduced.

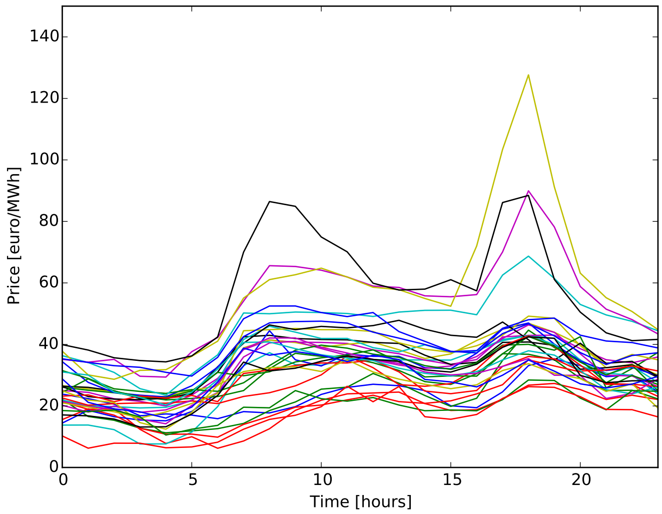


Figure 2.2: Historical day-ahead prices, January 2016

2.3.1 Usage of the power plant depending on the day-ahead prices

As the price of the electricity produced by the flexible power plant is quite high, we can ask us if the price of the day-ahead market will be high enough to start these power plants.

In this test, we will check how many days the power plants will start depending on the day-ahead prices. The power plants are considered shut-down at the start of the day. This hypothesis can be justify because the prices of the day-ahead market are most of the time lower during the night. So, these flexible power plants are generally running during the days and shut down at night.

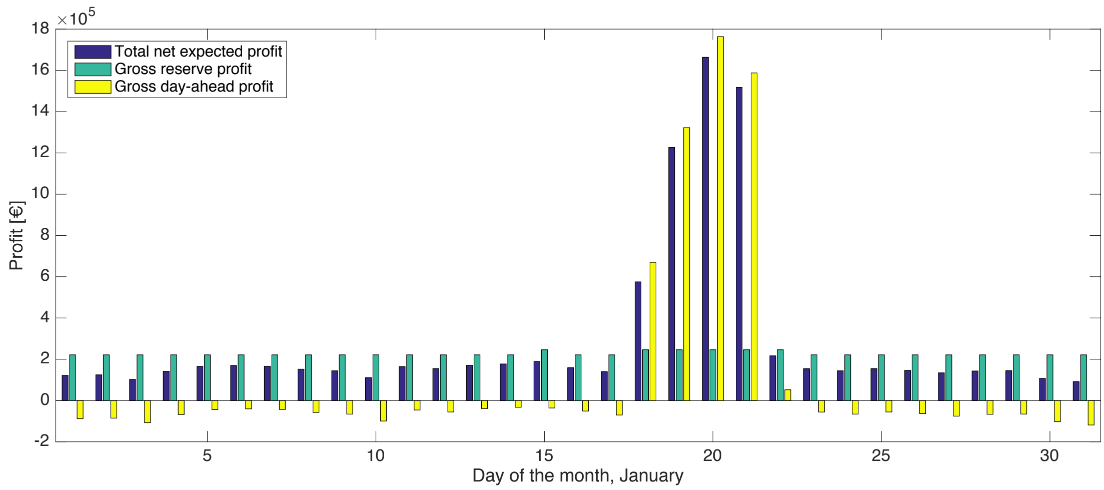


Figure 2.3: Expected profit of the PBUC of the entire pool of CCGTs, January 2016

Figure 2.3 shows the total expected profit of the pool, the gross reserve profit and the gross day-ahead profit. These two gross profits are taken without taking into account start-up and no load cost. In fact, these profits only consider the benefit and the loss only linked with their markets. For the reserve, it only considers the profit made by the capacity bid in the reserve as the activation price is compensated by the TSO. For the day-ahead, it includes the income from the day-ahead market and the loss needed to create this electricity.

This figure highlights well the fact that this kind of power plants are most of the time out of the money in the day-ahead market. The reserve market makes the pool of CCGTs profitable during all the month. It is not obvious to see but on the 15th, 18th, 19th, 20th, 21th and 22th of January the gross reserve profit are a bit higher than the other days. In fact, these days two power plants or more start so the entire reserve capacity can be handled. Indeed, it is not the case for one power plant due to the relation between the quantity bid in the reserve and the ramp rate (cf. Equations (2.32) and (2.33)). At least one power plant of the pool runs each day of the month. The reserve capacity is fulfil during all the month at least for a big part of it. So, this model fits to the fact that the reserve capacity are monthly contracted.

Regarding the day-ahead profit, the pool of CCGTs does not make benefit often as it was supposed to do. However, when it makes profit, it can nearly increase tenfold profit from these power plants. It underlines the need to well predict the day-ahead prices. Fortunately, the prices seem correlated from day to day.

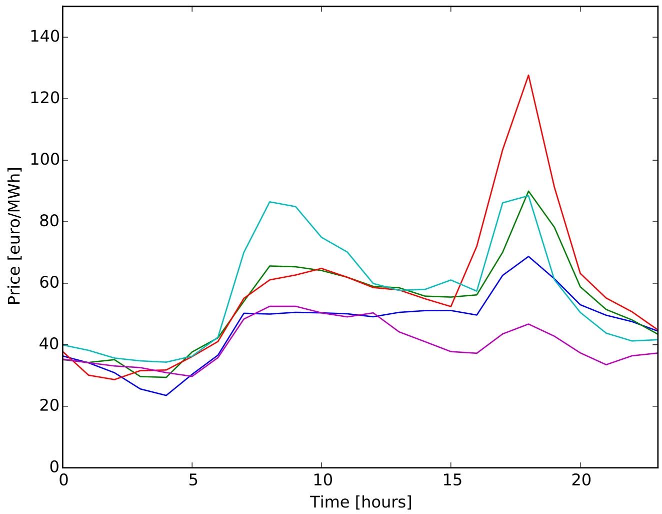


Figure 2.4: Historical prices which allow the pool of CCGTs to make profit in the day-ahead market

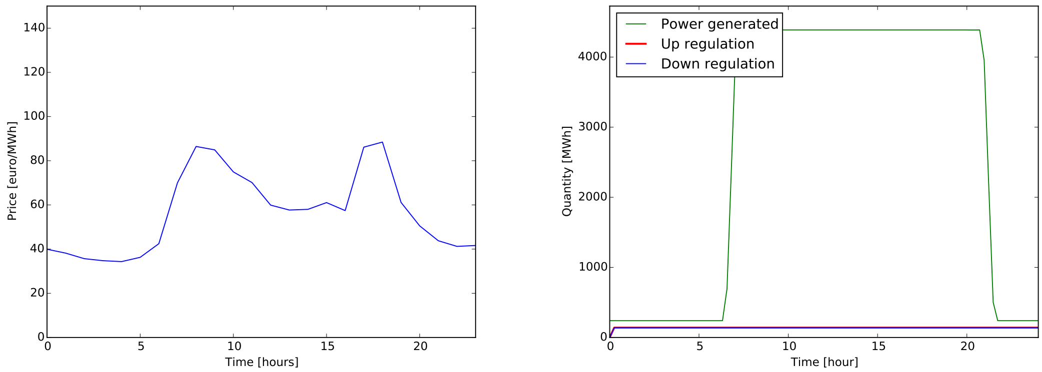
In FIGURE 2.4, it shows the day-ahead price signals which allows the pool of CCGTs to make profit in the day-ahead market. A lot of price signals do not allow profit while these prices are way above the marginal price of some CCGT. This behaviour can be explained by the high price to start-up these power plants and the no load cost which must be added to the problem.

2.3.2 Global bidding behavior

In Figure 2.5(b) and 2.6(b), the power generated bids in the day-ahead market and the power reserved for the up and-down regulation for two different days are represented. The behaviour of the historical prices of the 3th and 21th of January are represented in Figure 2.6(a) and 2.5(a). These days were chosen because they show two different behaviours. One have a positive benefit in the day-ahead market and the other not.

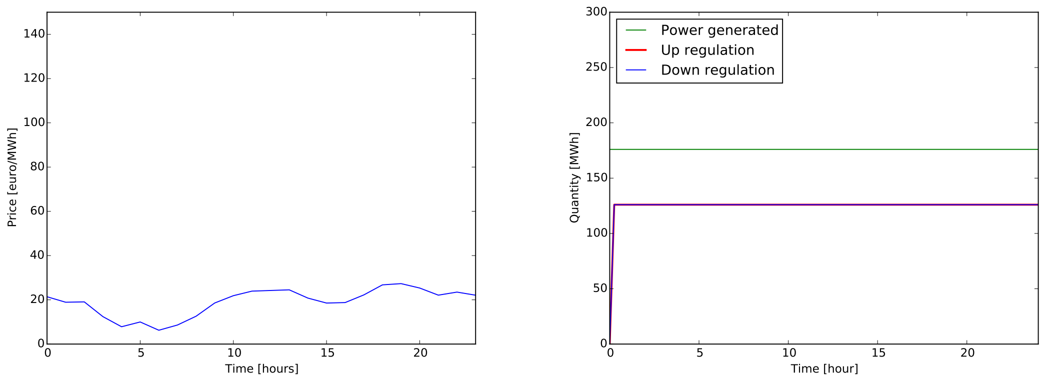
The hypothesis that the power plants are shut-down every morning is not totally confirmed but it is nearly the case as all the power plants shut-down except the one which handle the capacity reserve. So, by considering that these power plants are shut-down every day, the profit is underestimated as we take into account the start-up cost every day.

In Figure 2.6(b), the power generated is just sufficient to allow down-regulation without encounter the constraint on the minimal power limit. In fact, one power plant bids the biggest quantity it can in the reserve market and generates the minimum power it can to bid in the day-ahead market. This behaviour shows the bigger interest to bid in the reserve market when prices in the day-ahead are low. This figure illustrates the behaviour of the model most of the day during the month.



(a) Price scenario (b) State of the system

Figure 2.5: Global behavior of the model on the 21st of January



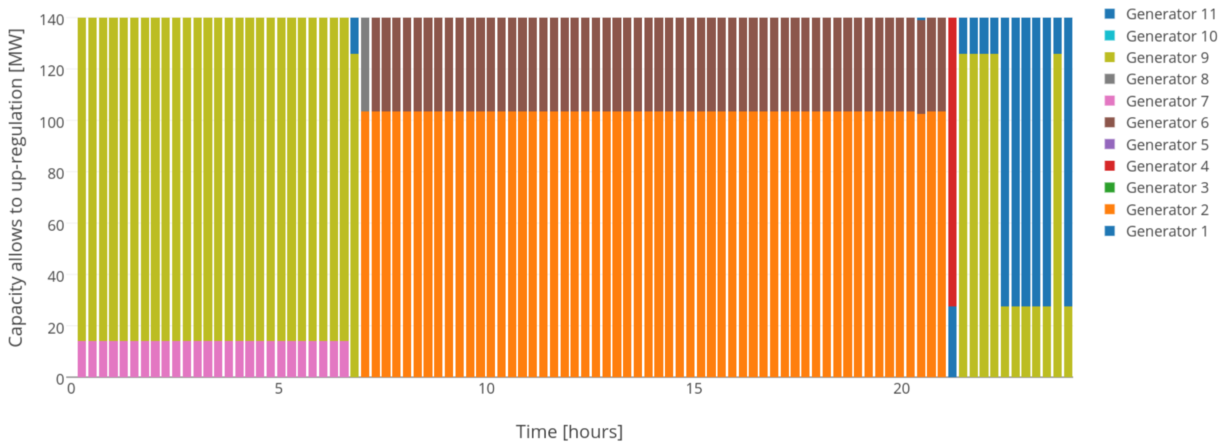
(a) Price scenario (b) State of the system

Figure 2.6: Global behavior of the model on the 3rd of January

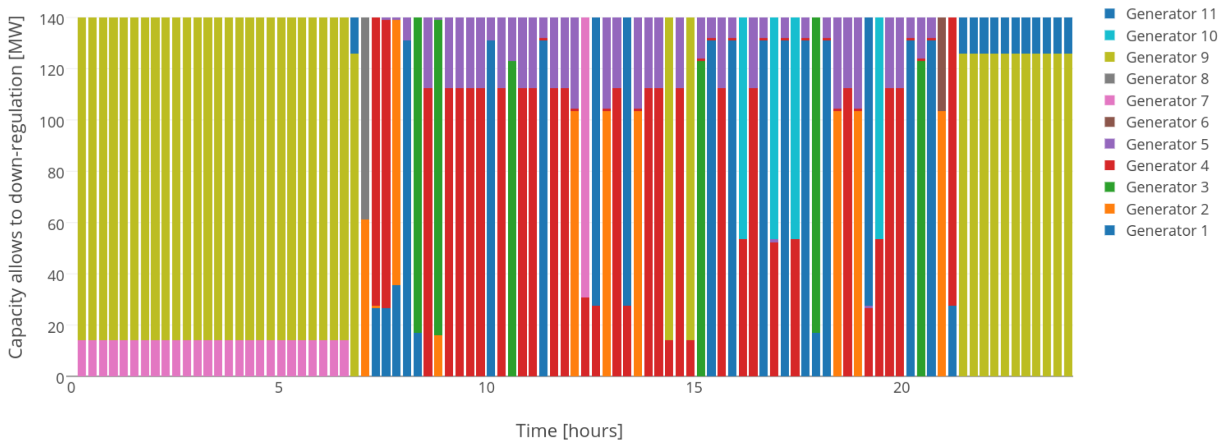
2.3.3 Sharing of the capacity reserve between the power plants of the pool

In the model presented, the power plants can not ramp up or down when this provides a capacity to the reserve market. The goal of this section is to highlight the fact that this constraint is correctly handle by the model.

The Figures 2.7(a) and 2.13(b) show the allocation of the reserve capacity between the different generators of the pool on the 21st of January. It is clear that the generators handle one after the other when the plants need to increase their energy production. The generators which handle the capacity of reserve when all the generators are at their maximal output are obviously those with the higher marginal cost. For the down-regulation it is a bit messy because there is no constraint that forces one instead of the other. These figures need to be liaise with the Figure 2.5(b).



(a) Up-regulation



(b) Down-regulation

Figure 2.7: Allocation of the capacity reserve between the different power plants on the 21st of January

2.3.4 Settlement of the imbalance price

In Figure 2.8, the imbalance prices on the 21st of January are showed. To understand this graph, the Figure 2.9 shows the Net Volume Regulation over a day. The default value is when the pool does not bid enough in the reserve market so it shows a default value of 100 €. When there is no price, it means that the net regulation volume is equal to zero. There is only one default price on the first time step of the model due to the limitation of the model.

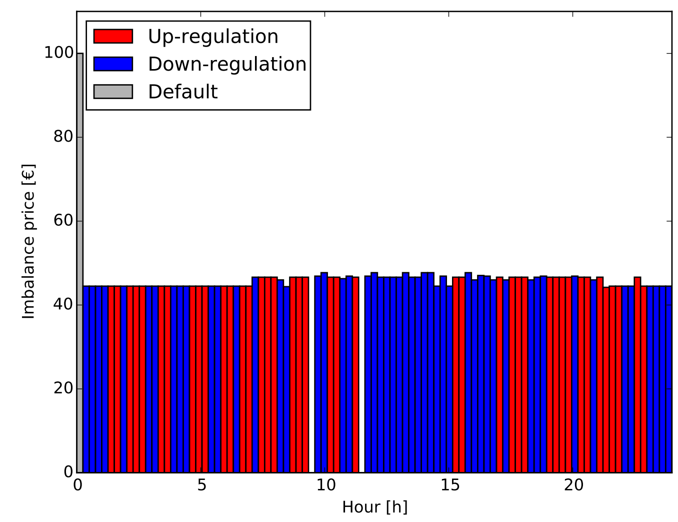


Figure 2.8: Imbalance price on 21st of January

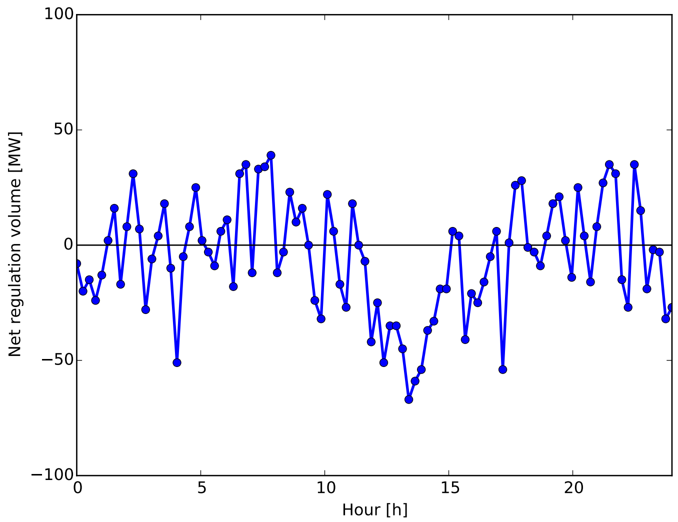


Figure 2.9: Scenario of a net regulation volume on 21st of January

As the PBUC does not take into account every type of power plants, the imbalance prices do not fit with reality.

To continue the work with realistic imbalance prices, the global model will be slightly changed on the part of the imbalance price. This new global model of the electricity market can be found in Figure 2.11

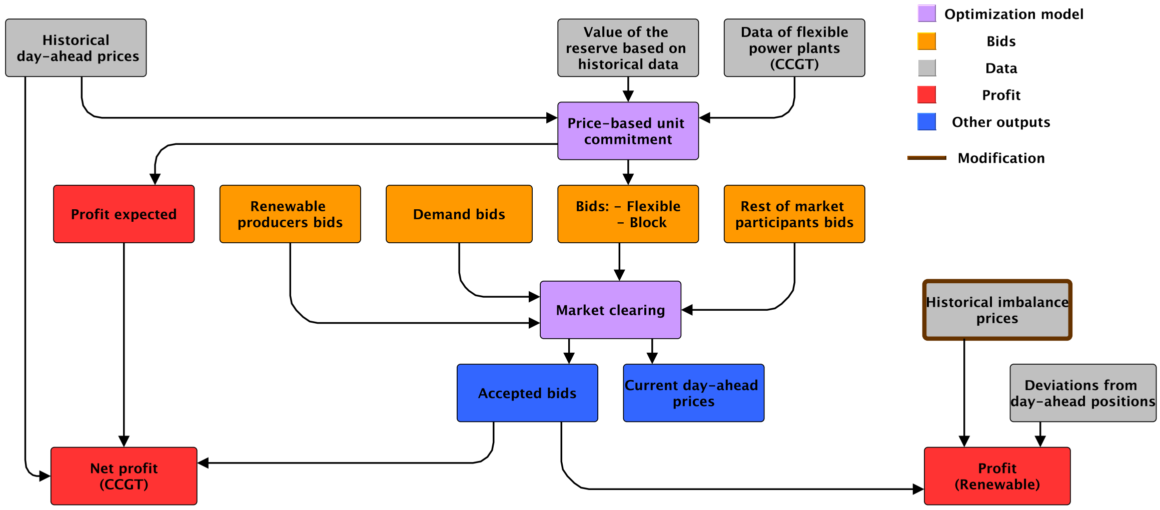


Figure 2.10: Review of the global model of the electrical system

2.3.5 Evolution of the gross reserve profit compared to the day-ahead prices

As we saw in Figure 2.6, we see that even with low day-ahead prices nearly all the reserve is provided. The following test takes a constant signal for the day-ahead prices and the goal is to determine when this reserve will not be profitable.

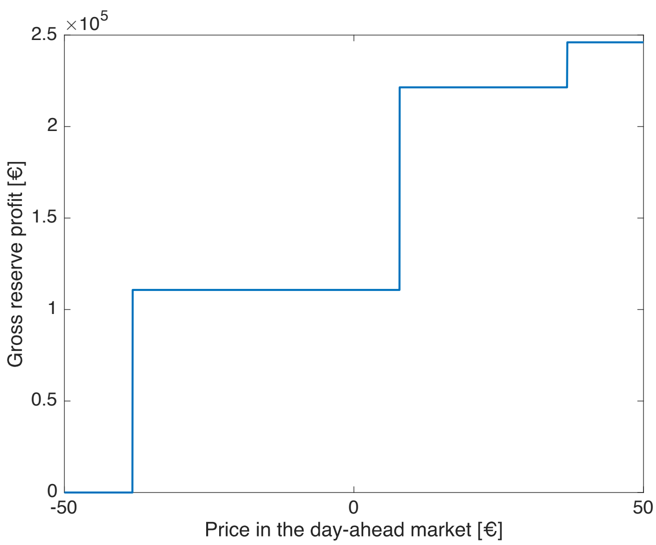


Figure 2.11: Evolution of the gross reserve profit with respect to the day-ahead price

As it can be seen on this figure, there are four steps in this graph :

1. $\rho^D \in [-\infty, -38.2]$: No reserve provided
2. $\rho^D \in [-38.2, 7.9]$: 126MW provided in the up-regulation
3. $\rho^D \in [7.9, 36.8]$: 126MW provided in the up-regulation and down-regulation

4. $\rho^D \in [36.8, \infty]$: 140MW provided in the up-regulation and down-regulation

This graph shows that the day-ahead prices need to be really low to decrease the profit made by the reserve. These results need to be put into perspective with the fact that we impose the minimal output power as the data were not provided. This is important to know; it can influence a lot this graph. Indeed, the PBUC tries to minimize the electricity generated bid in the day-ahead market when the day-ahead prices are low. The last step appears due to the constraint linking the quantity bid and the ramp rate which fixes the maximum quantity bid in the reserve for this generator to 126 MW.

2.3.6 Sensitivity analysis on the CCGT data

The goal of this section is to make a sensitivity analysis on the data of the CCGT which defines the flexibility :

- $D^{min,up}$: Minimum up time
- $D^{min,down}$: Minimum down time
- ΔP : Ramp rate

The tests will be done with different historical prices which allow different behaviours of the pool. We will take the price signal of the 3rd and the 21st of January. The entire pool of CCGTs will be tested and the entire characteristics of the power plants will be modify while we will be looking at the change on the different profits.

Analysis on the Minimum Down time

In the previous section, we settle that these power plants do not start more than once a day due to the huge start-up cost. So the study of the minimum down time in a day is no longer interesting as we will not remark anything. The only way to see a change is to play on the time that the power plant was off before this day.

Analysis on the Minimum Up Time

In Figure 2.12, the evolution of the expected profit with respect to a change in the minimum up time of all the power plants is showed. We have a decrease of the profit as we reach about 14 hours of minimum up time. We can understand this behaviour by looking at the Figure 2.5(b) where we see that some power plants turn off about 15 hours after being turn on. So, we can expect a decrease of the profit if we constrain more the system.

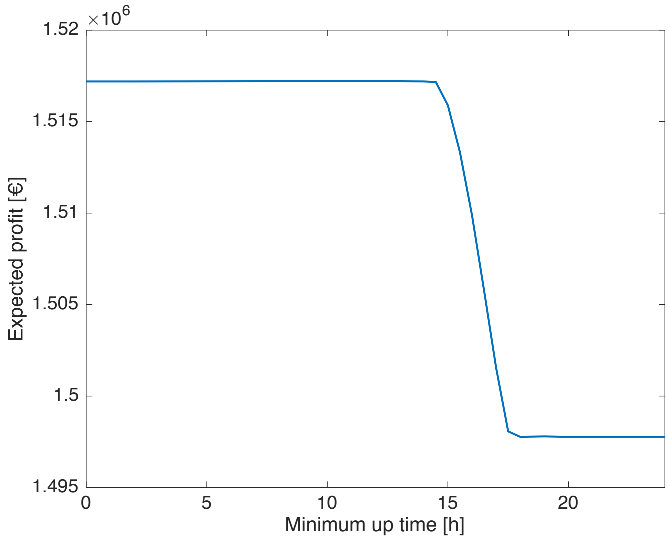


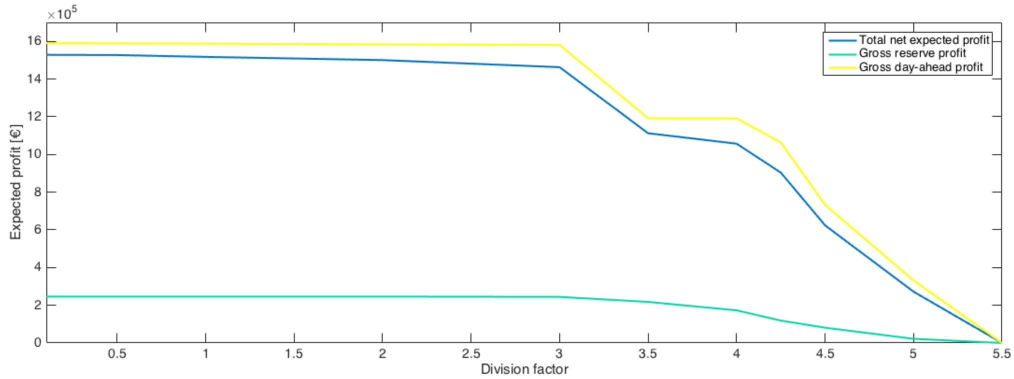
Figure 2.12: Evolution of the expected profit with respect to the minimum up time

The expected profit decreases of about 2 % which shows that the model is not really sensitive to a change of minimum up time. This can be explained as the minimum power output is really low (50 MW) which allows the power plants not to turn off and to make a smaller loss than if the minimum power output was higher. Furthermore, the on time of the pool with the standard value of minimum up time is already high. We could more see the impact of the change of minimum up time with a scenario where the power plants are on less longer.

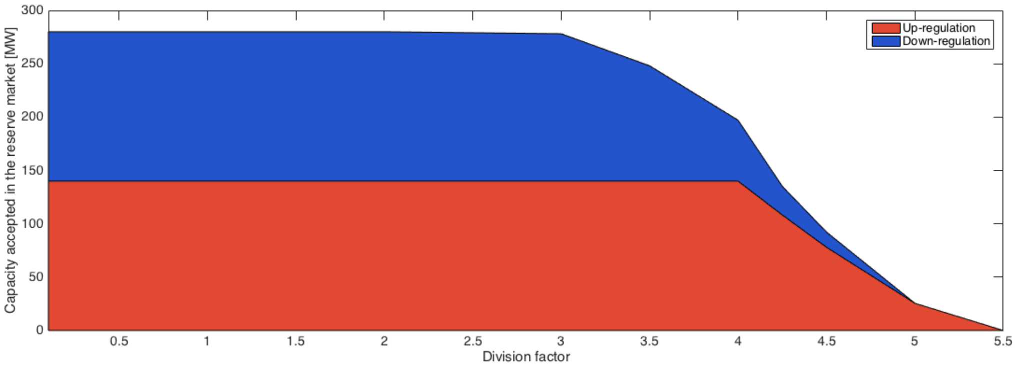
Analysis on the Ramp rate

The ramp rate is a characteristic really significant in power system. This allows this kind of power plants to be important as they provide electricity really quickly to fulfil lack of energy. In this test, the maximum ramp up and down limit will be divide by a factor and we will see the impact on the global profit, the gross reserve profit, the gross day-ahead profit and the capacity bid in the reserve for up and down regulation.

In Figure 2.13, the profit and the capacity allowed to the reserve vary compared to the division factor of the ramp rate are represented. First, an increase of ramp rate does not add a real value to the pool of power plants as we see the profit does not increase much if the division factor is below 1. Then, as the ramp rates are more and more divided the profit and the quantity bid in reserve decrease as expected. The down-regulation decreases faster than the up-regulation which is obvious as it is easier to allow up-regulation as the power plants need to produce more electricity to allow down-regulation. This decrease starts at about a division by 3 of all the ramp rate which state the ramp rate of all the pool between 210 and 350 MW/h. The profit reaches 0 at about a division of 5.5 which states the ramp rate of all the pool between 115 and 190 MW/h which is way above the condition to enter in the reserve (60 MW/h).



(a) Expected profit

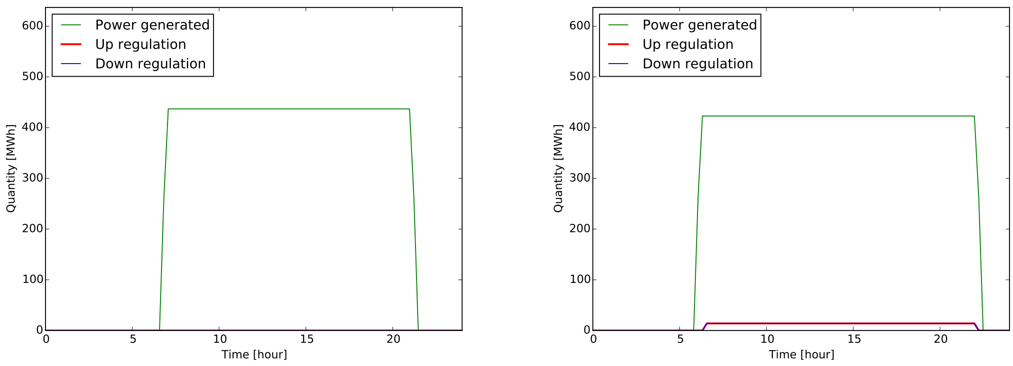


(b) Allocation of capacity reserve

Figure 2.13: Variation of profit and capacity reserve compared to a change of ramp rate of all the pool

2.3.7 Change in the contract duration for reservation of capacity

The duration of the contract for the reservation of the capacity tends to switch from long term (yearly, monthly) to a reservation per time step. The goal of this section is to understand in which configuration the modification of the duration of these contracts will impact the behavior and the profit of the generators. The last tests show that even if the day-ahead prices are low bid in the reserve market is still worth. To reduce the contract duration to a time period, the equation (2.34) and (2.35) will be removed from the model. To highlight the value bring by the change of time duration, special cases must be taken into account. Indeed, the impossibility to ramp up or down when the power plant bid in the reserve while the need to bid for the all day due to contract duration can be problematic. This occurs if the GenCo has only one power plant or a pool which can not share the reserved capacity when this pool needs to ramp up or down when there is an opportunity in the day-ahead market.
The test which values this change is a PBUC with only one power plant. The first generator of the TABLE A.1 is taken into account and the maximal power bid in the reserve (G^{max}) is a tenth of the maximal power (14 MW) as the maximal output of the generator (437 MW) is more or less a tenth of the sum of the maximal output of the pool (4527,3 MW).



(a) Long time contract

(b) Time step contract

Figure 2.14: State of the system on 21st January with one power plant regarding the time duration of the contract

In Figure 2.14, the state of the system regarding the time duration is showed. The release of the constraints on the time duration allows an increase of the profit of 9 %.

This test highlights again the importance of large pool to allow this kind of power plants to be profitable on the reserve market. Fortunately, the entirety of the CCGTs of a country is often owned by few companies. Furthermore, the added value of the reduction of time duration of the contracts is clearly seen. However, it is easier to enter the market with these contracts. So, the amount of offers can increase a lot and it will be more tricky to be accepted in the reserve market.

2.4 Conclusion

This chapter presents a model of a bidding strategy for two markets (day-ahead and reserve). This model is used for flexible power plants and especially for Combine-cycled gas turbine. The price-based unit commitment model to perform this model is governed by deterministic prices. To improve the model, prediction of prices can be take into account but often historical prices of the previous day are a good forecast of the future prices. The tests made with the model show that the day-ahead market is not often profitable for this kind of power plants and only the reserve market keeps these plants profitable each day of the month due to their ramp rate. This kind of power plants can be interesting if the maximal capacity asked by the TSO increases due to the rise of renewable in the system. The implementation of an intra-day market can be interesting to see if these power plants can gain consequent profit thanks to it. This model can be switched to stochastic programming which brings an average behaviour of the system thanks to the different scenarios of that kind of programming.

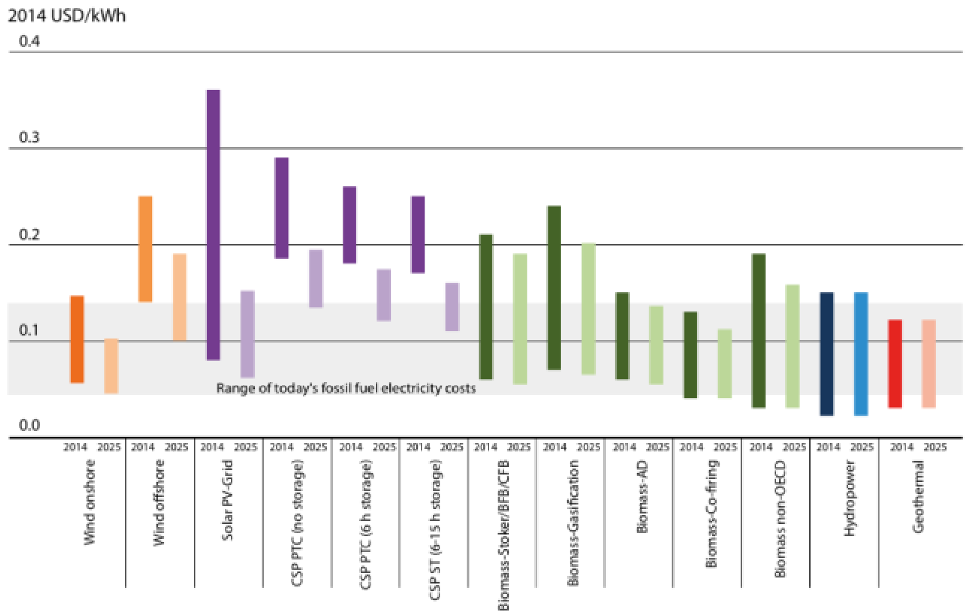
Chapter 3

Bidding renewable in electrical markets

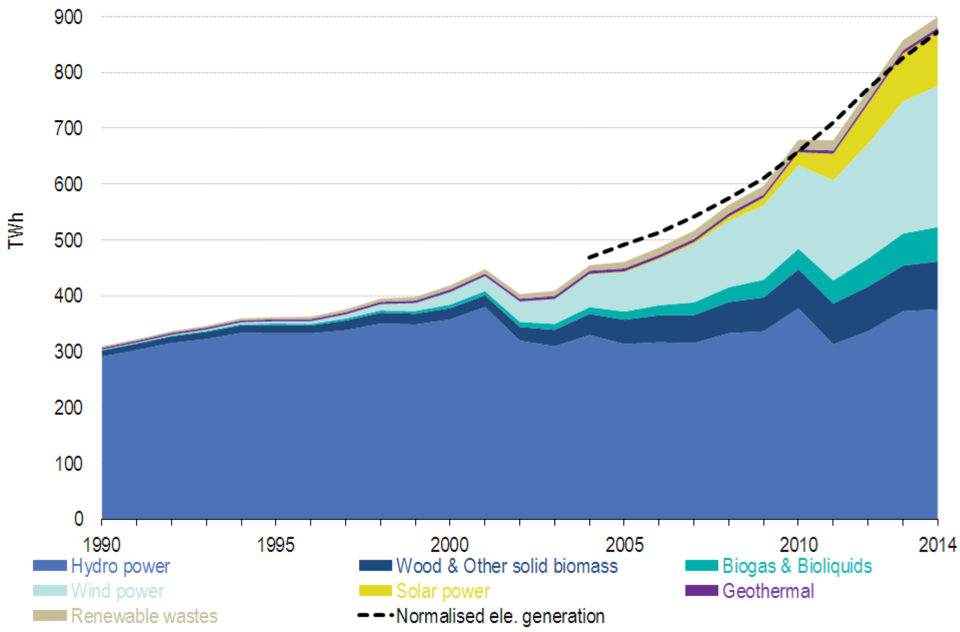
3.1 Introduction

During the last decade, the technological development and the political pressure led to a growth of the part of renewable in Belgium and all over the world (Cfr. Figure 3.1(b)). This growth was sustained by political helps as tax credits or feed-in tariffs to ease the market participation of renewable producers. As the renewable technologies become more efficient and cheaper (Cfr. Figure 3.1(a)), the renewables need less and less governmental incentive to be competitive. The renewable power producers tend to bid in the markets with the same rules as other producers. These renewable power producers need to deal with price risk.

As the behaviour of a renewable generator is really different than a CCGT or other types of generators, it seems interesting to study the way to bid them in the market. The main differences with conventional power producers are the uncertain power that the renewable could deliver at a certain time and the variable payback that they can earn from these generators. The renewable producers must deal in multiples market as they cannot be sure for their bidding quantities. So they must compensate as the real-time deviation from their previous bids is penalized by the market.



(a) LCOE ranges by renewable power generation technology among 2014 and 2015 [14]

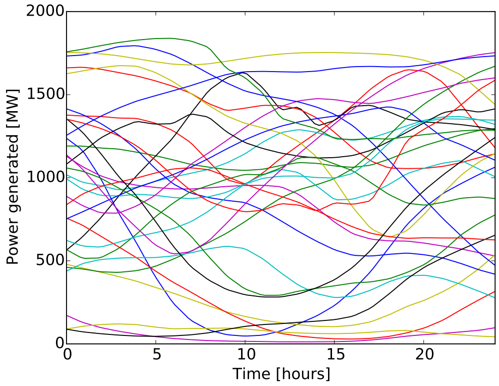


(b) Gross electricity generation from renewable sources in EU-28, 1990-2014 [10]

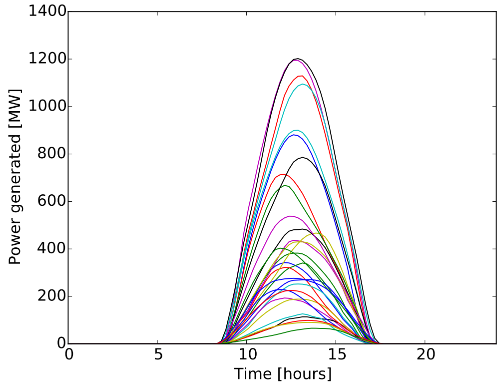
Figure 3.1: Price and capacity evolution of renewables

3.2 Data used

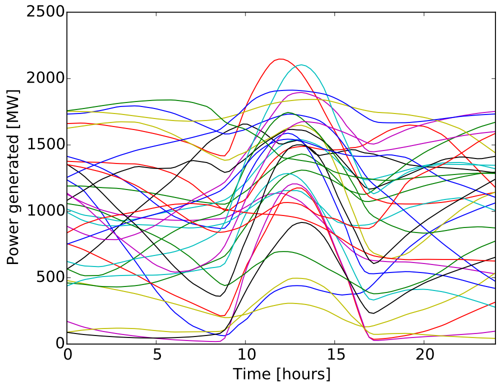
In Figure 3.2, the solar and wind generation in Belgium in January 2016 are showed. An interesting value to put in relation with these figures is the value of the capacity installed of solar and wind power which are respectively 2953 and 1961 MW.



(a) Wind production



(b) Solar production



(c) Total production

Figure 3.2: Historical renewable day-ahead forecast production signals, January 2016

3.3 Simple bidding approach in a one-price balancing market

In this section, a way of bidding renewables is presented [19]. Then, the benefits and the drawbacks of this model are discussed.

First, some assumptions are taken into account which are nearly the same as the ones used in the PBUC:

- The producers can only trades their electricity at the day-ahead and at the balancing market.
- There is only uncertainty on the production volume, the market prices are deterministic and known in advance.
- The producers are price-takers, i.e. they do not influence the market prices with their bidding strategies.
- The producer is risk-neutral, i.e. he only wants to maximize his expected profit without taking account of the loss.

In a one price-balancing market, deviations from day-ahead contracts are traded at a unique balancing price regardless of the sign of producer and system imbalances. On the one hand, the balancing price is normally higher than the day-ahead price in up-regulation which means that the system is in deficit of power production as a result of all deviations from producers and consumers with respect to their previous positions. On the other hand, the balancing price is normally lower than the day-ahead price in down-regulation. This allows to have arbitrage which is the practice of taking advantage of a price difference between two or more markets: striking a combination of matching deals that capitalize upon the imbalance, the profit being the difference between the market prices. [22]
Indeed, the producers can sell their excess of electricity compared to their day-ahead position at a higher price than the day-ahead price if the system is in up-regulation and they can repurchase their productions deficit at a lower price. However, if the the two imbalances are of the same sign, the arbitrage opportunity disappears. In Figure 3.3, the arbitrage opportunity is resumed on this graph

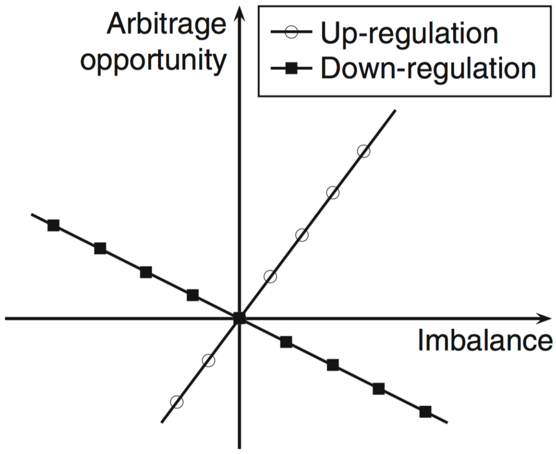


Figure 3.3: Producer imbalance and arbitrage opportunity between balancing and day-ahead markets in the one-price system [19]

The profit at time t can be expressed as:

$$\widetilde{\pi}_t = \rho_t^D Q_t^D + \rho_t^B \widetilde{Q_t^B} \tag{3.1}$$

where $\widetilde{\pi}_t$ is the profit made by the producer at time t, $Q_t^D/\widetilde{Q_t^B}$ is the quantity traded in the day-ahead/balancing market at time t, ρ_t^D/ρ_t^B is the *deterministic* price on the day-ahead/balancing market at time t.

The only decision variable is Q_t^D. In fact, the prices of the different markets and the energy which will be traded in the balancing market is not something that can be influenced. The producers must try to estimate well the production that their generators will produce.

The quantity traded in the balancing market can be rewritten as :

$$\widetilde{Q_t^B} = \widetilde{Q}_t - Q_t^D \tag{3.2}$$

where $\widetilde{Q}_t$ is the expected production.

Replacing (3.2) into (3.1), the profit can be rewritten as:

$$\widetilde{\pi}_t = (\rho_t^D - \rho_t^B) Q_t^D + \rho_t^B \widetilde{Q}_t \tag{3.3}$$

To maximize this equation, only the first term will act as the producer cannot have an influence on the second term. As only the first term acts, 3 trivial solutions can be found :

- $\rho_t^D > \rho_t^B$: The producers bid in the day-ahead market their expected production. Thus, they compensate on the balancing market the deviation from their position.
- $\rho_t^D < \rho_t^B$: The producers bid nothing in the day-ahead market and sell all their electricity in the balancing market.
- $\rho_t^D = \rho_t^B$: The producers sell in the two markets without preference.

This model leads to very high expected profit for the renewable producers. However, some assumptions seem to be too far from the reality to estimate the profit of renewable producers with it. On the one hand, estimate the day-ahead prices is an issue which has lead to lots of studies from the power system researchers and statisticians. These prices can be estimated in an acceptable range. On the other hand, consider the balancing prices known in advance is really bold from the power systems researchers as it depends on many parameters hard to predict. Furthermore, the model considers the electricity bid in the two markets automatically accepted. For the day-ahead, as the renewable bid in this market at a zero price, this assumption can hold. For the balancing market, consider the entire production to be accepted without changing the price is not realistic. Indeed, the energy traded in the balancing market is not of the amount of the quantity produced by all the renewable producers which can happen if they all follow the same rule.

Though this model includes a lot of issues, it introduces the idea that bad predictions are not just a penalty but can be used as a way of earn money.

3.4 Estimation of the renewable producers profit

This section tries to quantify the profit earned by the renewable producers in Belgium with a simple bidding strategy. First, the renewable producers bid their entire expected produced quantities in the day-ahead market. Then, they balance their deviations from their initial positions on the day-ahead market on the balancing market. The added value of a non intended arbitrage can be estimate.

The profit per time step is defined as,

$$\pi_t = \rho_t^D Q_t^{forecast} + \rho_t^{UP} Q_t^{POS} - \rho_t^{DW} Q_t^{NEG} \tag{3.4}$$

where $Q_t^{forecast}$ is the forecast quantity when the producer bids in the day-ahead market. $Q_t^{real-time}$ is the value of the quantity really delivered. Further explanations on the two balancing prices (ρ_t^{UP} and ρ_t^{DW}) of a one-price balancing market can be found in Section 1.2. The imbalance quantities of the renewable power plants (Q_t^{POS} and Q_t^{NEG}) are defined in (3.5) and (3.6). The quantity bid in the day-ahead market as well as the quantity traded in the balancing are considered accepted. To have an order of magnitude, the Figure 3.4 shows the standard deviation of renewable bidding imbalance.

$$Q_t^{POS} = \begin{cases} |Q_t^{real-time} - Q_t^{forecast}| & \text{if} \quad Q_t^{real-time} > Q_t^{forecast} \\ 0 & \text{else} \end{cases} \tag{3.5}$$

$$Q_t^{NEG} = \begin{cases} |Q_t^{real-time} - Q_t^{forecast}| & \text{if} \quad Q_t^{real-time} < Q_t^{forecast} \\ 0 & \text{else} \end{cases} \tag{3.6}$$

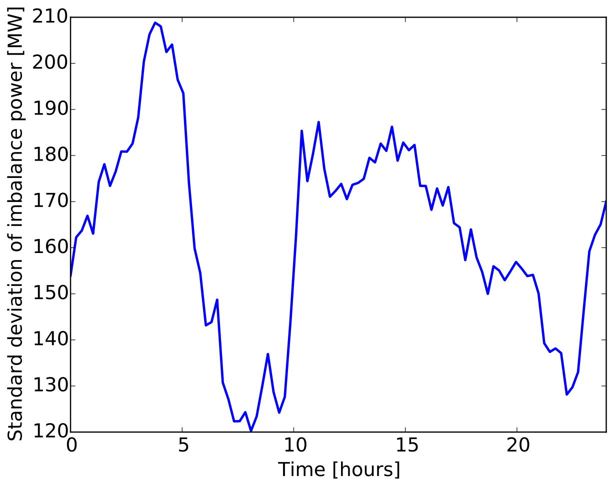


Figure 3.4: Standard deviation of renewable bidding imbalance, January 2016

The expected profit of each day of January is represented in the Figure 3.5. The losses induced by wrong forecast are also computed; if these losses are negative the electricity traded in the balancing market brings an added value to the profit. An interesting comparison can be done with the graph of expected profit done by CCGTs (cf. Figure 2.3) as the power installed is nearly the same. About the losses due to bad forecast, the mean of it is negative which means that these deviations from their day-ahead positions lead to a profit to the renewable producer. However, this increase of profit is value at 4918.2 €/day which is small compared to the total profit of the pool.

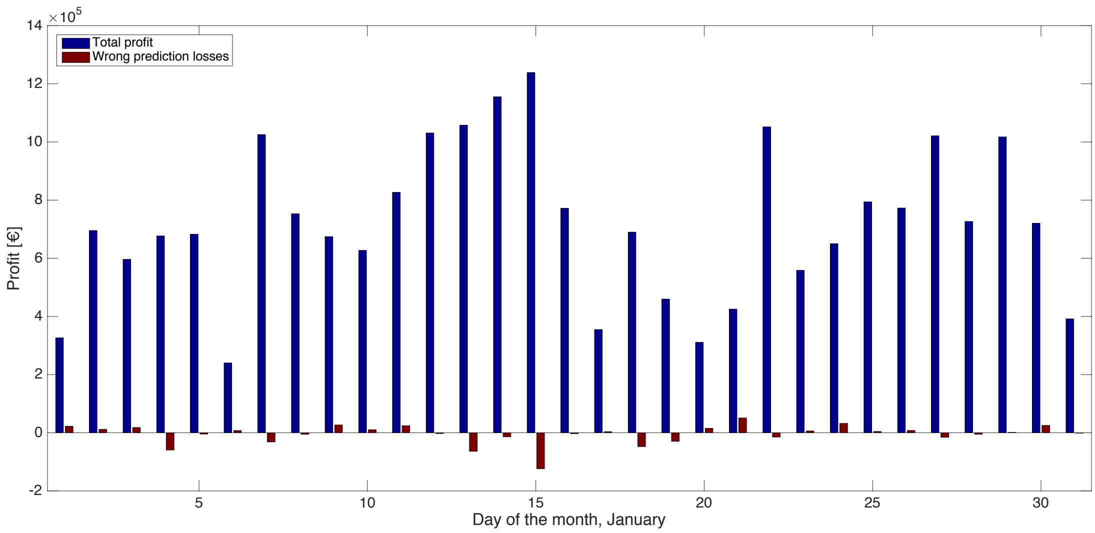


Figure 3.5: Profit of all the Belgian renewable producers (solar and wind)

3.5 Conclusion

This chapter presents a model of a bidding strategy as well as an estimation of the possible profit earned by the entire producers of renewables (solar and wind) in Belgium. This chapter has no pretense to do a review of bidding strategy for renewables or to present a complex model of it. The bidding strategy was taken because it has nearly the same assumptions as the bidding strategy for flexible power plants (deterministic price, two markets, price taker,...). This chapter tries to give interesting order of magnitude for renewables (production, deviation from a day-ahead forecast, profit). The maximum quantity that the producers can exchange is something that can reduce the profit made with it. For further work, the inclusion of batteries or hydro power plants can be interesting to valuate well the benefit made with this market.

Chapter 4

Market clearing: conversion of the bids

The goal of this section is to present how the energy produced by the PBUC will be converted in different bids to put in the market clearing.

4.1 Overview of market clearing

The market clearing used allows block and continuous bids. This market clearing is described in the article of Mehdi Madani [18] and was programmed by Sébastien Mathieu.

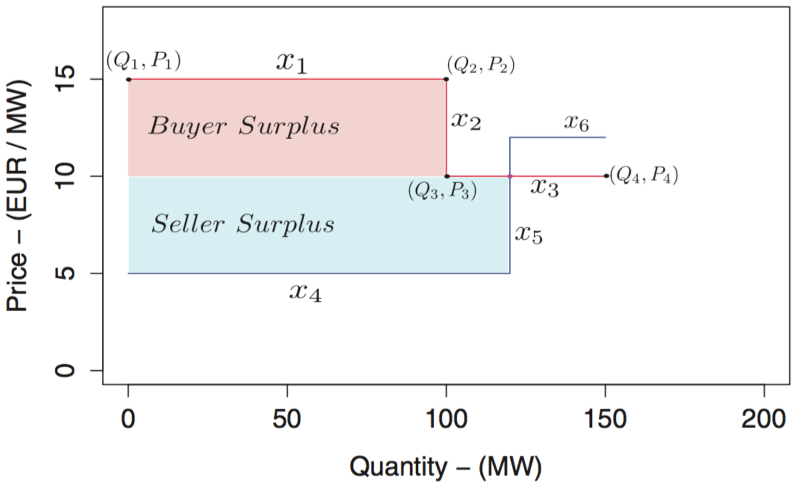


Figure 4.1: Market clearing example [18]

The goal of the optimization problem is to maximize the welfare which means the maximization of the seller and buyer surplus (cf. Figure 4.1).

On the one hand, an important rule in Europe is the prohibition of paradoxically accepted block (PAB), i.e. no order can be accepted while loosing money even it increases the total welfare. On the other hand, a block order could be rejected although it is in the money which is called paradoxically rejected orders.

The big challenge with the market clearing is the fact that the feasible region of the optimization problem can turn non-convex due to the presence of binary variables (block bids). Different approaches exist to overcome this issue as constraint linking primal and dual. This solution can be read in the article cited above.

4.2 Bids creation for the combined-cycle gas turbine power plants in the day-ahead market

The goal of this section is to convert the energy produced by the power plants in flexible or block bids. This conversion must be done while considering the possible profit of the power plant, the possibility to be accepted or not in the market and characteristics of the power plant.

4.2.1 Types of CCGT used in the model

To know how to bid well the power produces by the CCGT, we need to know better the characteristics of them. These CCGTs are separate in two categories which are represented in Figure 4.2.

1. First, there are CCGTs without No Load Cost which give to the cost curve a flat or a positive slope. But as you can see in the data in appendix there is no power plant without No Load Cost with increasing marginal cost.
2. Second, there are CCGTs with No Load Cost which give to the cost curve a decreasing slope. The cost will tend to the marginal cost of the last block of the piece-wise linear cost curve. The increase of the marginal cost in each block does not compensate the No Load Cost to invert the slope of the cost curve.

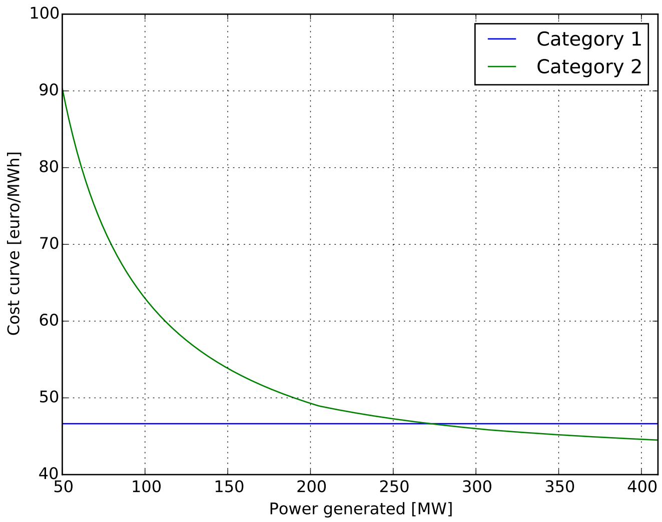


Figure 4.2: Real value of cost curves

This categorization have a critical importance in the bidding strategy.

Characteristics of the standard bids

First, the bid creation presented will consider the price-based unit commitment without the reserve market. Then, we will see the impact of the reserve market on the bid creation. The power generated at the output of the PBUC will be converted in flexible and block bid to put in the day-ahead market. Some really simple bid construction has been studied as in the paper of Ignacio Aravena [20] where the power was submitted in two or more bids: one corresponding to the minimum power output valuated at zero and the others corresponding to price increasing representing the cost curve of the generator.

The bid construction in this model is a bit different from the one cited before as the first bid takes account of the minimum output power of the power plant.

First, we will bid a block with all the power under the minimum power limit:

$$Q_{i,t} = P_i^{min} \qquad \rho_{b_{i,t}} = D_t(C_i^{fixed} s_{i,t} + C_{i,1}^{prop} P_{i,t}^{min})/P_i^{min} \tag{4.1}$$

where $Q_{i,t}$ is the amount of power in the bid for the generator i at time t and ρ_{b_t} is the price of the block bid.

Then, we can bid the rest of the power that we could produce in two ways. The categories that we have define before will help to made two strategies.

- **Category 1:** All the energy remaining is bidden with a flexible bid in the day-ahead market.

- **Category 2:** In this case, the cost curve is decreasing so it allows two ways of bidding. Either the GenCo gives priority to flexibility or favor low price.
  In the first approach, all the energy remaining will be bidden at the highest price of curve with a flexible bid. Like that the bid can be accepted in a continuous way avoiding losing money.
  In the second approach, the block bid is extended to take account of the minimal output power and all the energy remaining. Like that we have a lower price but the bid must be accepted all at once.
  The second approach will be favored as the prices of these power plants are already really high.

  Another better approach would be to have exclusive bid in the market clearing which allows the generator to bid a lot of possibilities and to fit better the cost curve to have more opportunities.

	Quantity [MW]	Price [€/MWh]	Type
Category 1	P_i^{min}	$D_t(C_i^{fixed} s_{i,t} + C_{i,1}^{prop} P_i^{min})/P_i^{min}$	`Block`
	$p_{i,t} - P_i^{min}$	$D_t(s_{i,t}(C_i^{fixed} + C_{i,1}^{prop} P_i^{min}) + \sum_{l=1}^{3} C_{i,l}^{prop} \delta_{i,t,l})/p_{i,t}$	`Flexible`
Category 2	$p_{i,t}$	$D_t(s_{i,t}(C_i^{fixed} + C_{i,1}^{prop} P_i^{min}) + \sum_{l=1}^{3} C_{i,l}^{prop} \delta_{i,t,l})/p_{i,t}$	`Block`

Table 4.1: Bids construction

In Table 4.1, the characteristics of the bids created are listed in a more mathematical way. The signification of all these symbols is widely explained in Section 2.2.1. These formulations are general. For example in category 1, the fact that there are no No Load Cost ($C_i^{fixed} = 0$) and a constant cost slope on the 3 blocks of the piecewise linear function of the variable cost ($C_{i,1}^{prop} = C_{i,2}^{prop} = C_{i,3}^{prop}$) leads us to easily find constant price for any power generated.
In such case, we will decrease the price of the block bid by an little ε to incite the market clearing to prefer the block bid if it has the choice between the two bids.

In this bidding strategy, the start-up cost is not taking into account. It is already considered in the price-based unit commitment so, if the forecast price is not too far from the actual price, we do not expect to do loss.

4.2.2 Addition of the reserve in the PBUC

For instance, the construction of the bids is made with a PBUC without the reserve market. The creation of bids must be reviewed as the power plant will start-up only to fulfil the reserve while the day-ahead price is really below the price needed to make profit with this market. So, when the GenCo bid in the day-ahead market and that the marginal cost of the power plants are way above the day-ahead price, the bid price will be settled at zero €/MWh. As the GenCo already made a loss on this market, it avoids making more loss by considering too high bidding prices with a low opportunity to be accepted in the market clearing.

4.3 Conclusion

This chapter presents a way to create bids from the output of a price-based unit commitment. The main goal to perform this conversion was to prevent losses for the GenCo. The conversion mainly depends on the cost curve of the power plant. The strategy behind this conversion was a bit blocked by the limited products that it was possible to bid in the market clearing. Indeed, exclusive bids can bring a real added value as the producers could bid special bid when his power plant starts up. We avoid the use of cost curve which could be interesting to have more possibilities to bid his electricity.

Chapter 5

Validation of the electricity system

5.1 Introduction

Almost all parts of the electrical system, as it is model in this master's thesis, have already been explained in the previous sections. All that remains to do is to link all these parts together to validate the bidding strategy used. This bidding strategy can be validated through the market clearing. All participants of the market are modelled in this section. The purpose of this market clearing with all participants is to know if the bids of the CCGTs will be accepted or not.

5.2 Modelling the rest of market participants

Model all market participants has always been a big issue of the power systems researchers. Indeed, the modelling of each market participants requests a lot of work and a lot of data not always easy to obtain.

5.2.1 Market sellers

The approach pursued to model the market sellers remaining is described as follows. In addition to bids of renewable and CCGT, two other participants will bid in the market clearing. The bidding behaviour of these two participants who represents the rest of the market participants is quite simple. The first participant model all the actors except the renewable producers with a price below the CCGT prices with a single flexible bid. Its role is to force the market clearing to accept or reject the bids of the CCGTs which is the goal of the section. Then, the second participant model all the actors with a price above the CCGT prices with a single flexible bid. Its role is to fulfil the possible lack between the demand and the generation. Thus, the market clearing does not deal with impossible matching problem. To have the desired behaviour, the price of the first bid is 20 €/MWh and for the second 70 €/MWh. The bidding price of the CCGTs is between 35 €/MWh and 50 €/MWh so the previous bidding prices will act as desired.

However, one issue remains as the quantity of the bid is not already settled. The Figure 5.1 shows a global view of the capacity installed in Belgium per production type [8]. As a reminder, the capacity installed is often far from the energy produced mostly with renewables (cf. Figure 3.2). In this figure we can avoid taking into account the solar, wind and nearly all the fossil gas as it was already done in the model. The bid will have a quantity between 6000 MW and 10000MW as nearly all the nuclear is considered running and the sum of all the production not already model leads to this maximal value. In general, this bid is considered with a quantity of about 7000 MW as the nuclear reactors are considered running and the capacity installed in the production type *Others* is mostly considered with must-run power plant (Coal, biomass). Therefore, a sensitivity analysis will be performed on the quantity of this bid in the following section. The second bid has a quantity of 8000MW to be sure that the demand is fulfilled at any time step.

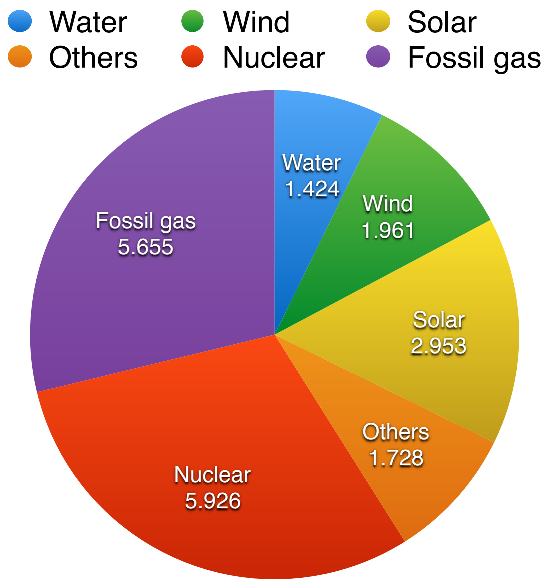


Figure 5.1: Capacity installed [MW] in Belgium per production type

5.2.2 Market buyers

The demand part of the market clearing is modelled as follows. Historical demand signals [8] (cf. Figure 5.2) are taken to bid in the market clearing. The price of this demand is settled at 100 €/MWh to accept all the bids sold in the market. This graph shows that the demand in Belgium in January 2016 is between 7000 MW and 14000 MW.

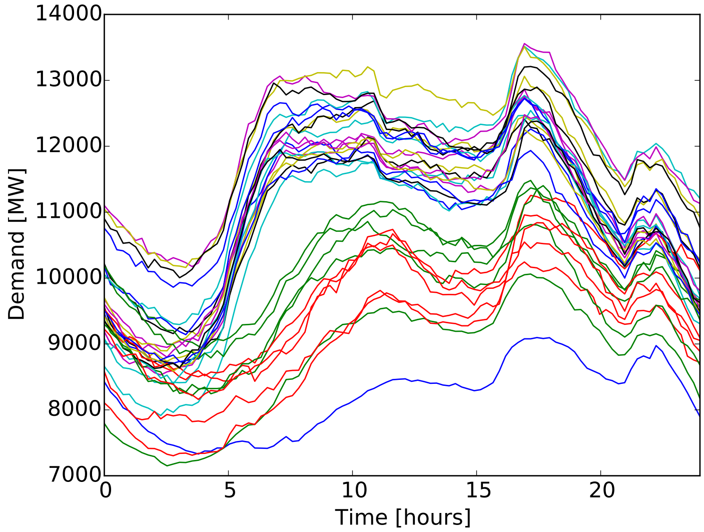


Figure 5.2: Historical demand signals, January 2016

5.3 Sensitivity analysis : modelling the rest of the market sellers

The modelling of the rest of the market participants is something tricky to perform. So, a sensitivity analysis on the quantity bid to represent the cheaper part of the rest of the market participants is achieved.

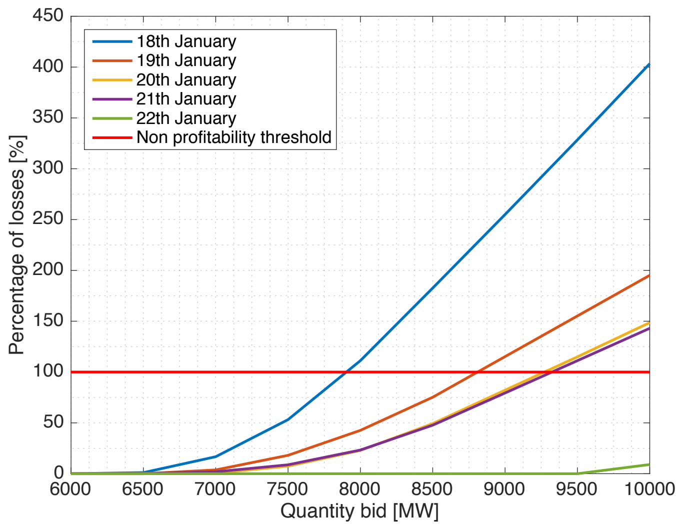


Figure 5.3: Evolution of the losses of the CCGTs bidding due to bid rejection with respect to quantity bid to model the rest of cheaper market participants

To perform this sensitivity analysis, as told before, we will change the quantity bid to model the rest of market participants with a cheaper bidding cost from 6000 MW to 10000 MW with steps of 500 MW while the market clearing with all the participants is solved. The value study in this sensitivity analysis is the percentage of losses compared to the expected profit calculated in the Section 2. To calculate the losses of the PBUC, the quantity rejected, after the market clearing, is multiplied by the historical day-ahead prices used in the PBUC. The prices created by the market clearing are not used. Indeed, our modelling of the other market participants do not allows to the market clearing a realistic range of prices.

The percentage of losses for the five days which have benefit in the day-ahead market are represented in Figure 5.3. The other days of the month do not suffer from losses in this sensitivity analysis. Obviously, the non profitability threshold is reached if the losses equal the total profit. This threshold is reached at different quantities between 7900 MW and 9400 MW. The quantity of the bid which represents the rest of cheaper market participants is generally considered at about 7000-7500 MW. With this assumption, the CCGTs do not suffer from losses which could prevent profit even if large losses (50%) can be encounter for some configuration. However, some wrong predictions on these others participants can lead to significant losses for the CCGTs. Furthermore, an increase of the production of renewable can shift the graph to the left increasing the loss in the different configuration.

5.4 Conclusion

This chapter presents a way to validate the bidding strategy done thanks to a market clearing. The idea was to make a model which defines a range where the bidding strategy used previously is still profitable. Even if the modelling of the other participants is gross, this validation model provides an idea of the pertinence of it. The profitable range found is quite acceptable if we refer to the capacity installed in Belgium. An improvement of this validation model could be the modelling of all the different participants with singular bidding strategies.

Chapter 6

Conclusion

This chapter provides a general conclusion of this master's thesis. Specific conclusions can be found at the end of each chapter.

First, this master's thesis focus on the understanding of the current electrical system and on the different magnitude of signals used in it. Then, a simplified model was created to represent the electrical system and try to mimic its main behaviours. The difficulty to mimic a global system leads to make lots of assumptions to focus on particular behaviour of the system. This work presents different parts of this system to give an overview of it to the reader. The model created includes a lot of limitations already mentioned in the different concluding sections of each chapter. The different price signals can be switched from deterministic to stochastic which could improve the results at the expense of the interpretability of these studies. Concerning the value of flexible power plants, it has be highlighted that these power plants can be useful to fulfil the reserve market. Currently, they are still interesting in our electrical system as the needs of flexibility can be fulfil only by hydro power plants. However, these flexible power plants will disappear if the increase of the part of renewable is not compensate by bigger capacity reserve where these flexible power plants shine.

Appendix A

CCGTs data

N°	Maximum output [MW]	No load cost [€/h]	Ramp up limit [MW/h]	Ramp down limit [MW/h]	Minimum Output [MW]
1	437	2898,27	1048,8	1048,8	`No data` *Default* : 50
2	460	0	828	828	`No data` *Default* : 50
3	410	2736,79	984	984	`No data` *Default* : 50
4	475	566,27	900	900	`No data` *Default* : 50
5	480,3	3359,7	864,54	864,54	`No data` *Default* : 50
6	350	0	630	630	`No data` *Default* : 50
7	485	0	873	873	`No data` *Default* : 50
8	350	1754,62	630	630	`No data` *Default* : 50
9	420	0	1008	1008	`No data` *Default* : 50
10	385	1930,03	693	693	`No data` *Default* : 50
11	375	0	900	900	`No data` *Default* : 50

Table A.1: Characteristics of the pool of CCGTs

N°	Minimum up time [h]	Minimum down time [h]	Start-up cost [€]	Cost slope [€/MW]			Upper limit [MW]		
				Block 1	Block 2	Block 3	Block 1	Block 2	Block 3
1	2	1	11.903,56	35,3717	39,351	40,2352	218,52	327,78	437
2	2	1	12.530,06	46,634	/	/	460	/	/
3	2	1	11.168,1	35,6011	39,6057	40,4962	205,02	307,49	410
4	2	1	10.214,73	45,8245	44,2173	43,9962	218,12	326,57	375
5	2	1	13.083,02	37,3071	41,504	42,4363	240,16	360,24	480,3
6	2	1	9.533,74	46,634	/	/	350	/	/
7	2	1	13.211,05	46,634	/	/	485	/	/
8	2	1	9.533,74	39,4519	42,343	45,2347	174,99	262,49	350
9	2	1	11.440,49	44,5008	/	/	420	/	/
10	2	1	10.487,12	39,4519	42,343	45,2347	192,49	288,74	385
11	2	1	10.214,73	46,634	/	/	375	/	/

Table A.1: Characteristics of the pool of CCGTs

Appendix B

Python codes

This section presents an overview of the code used to realize this master's thesis. The reader will have a better understanding of these codes if he wants to use them in the future.
These codes can be found in free access on `https://github.com/alexandreDanthine/MasterThesis`.

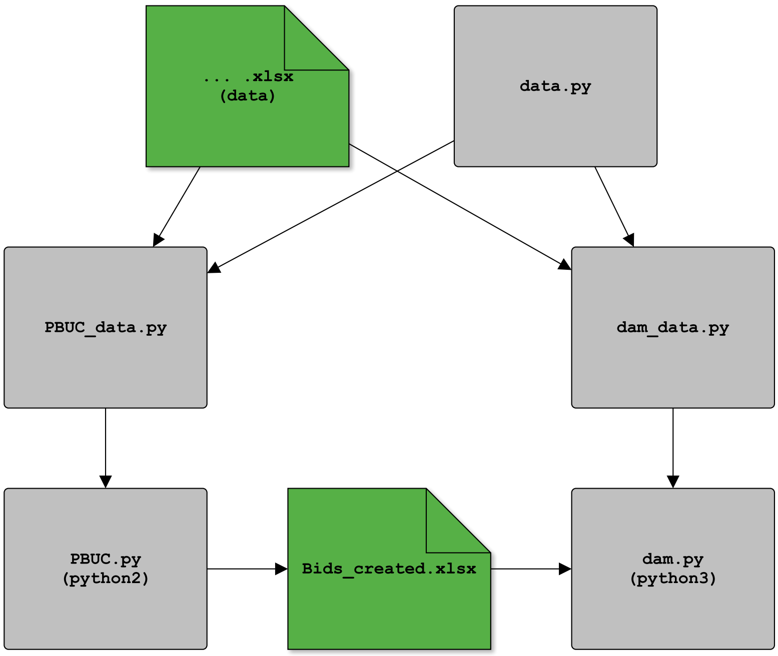


Figure B.1: Schematic representative of the code used in the master's thesis

In Figure B.1, an overview of the model used is presented. The model includes two parts : the price-based unit commitment and the market clearing of the day-ahead market.
A lot of data are needed to run these codes (solar forecast, wind forecast, historical prices,...). These data are written in EXCEL file. To read these while having an easy way to use it, two PYTHON files are needed. First, a file to literally allow the code to read in the file is needed and it is the role of `data.py`. Then, a file is needed to specify how we will order these data in different vectors and it is the role of `PBUC_data.py` and

`dam_data.py` which are related to the two parts of the code.
Obviously, `PBUC.py` and `dam.py` are the two main parts of the codes. They are linked by an EXCEL file which represents the bids created after the price-based unit commitment. In TABLE B.1, we see the characteristics of these bids and how it is written in the EXCEL file.

Quantity [MW]	Price [€/MWh]	Type of bid	Time step	N° generator
⋮	⋮	⋮	⋮	⋮

Table B.1: Data contained in the file `Bids_created.xlsx`

To provide some additional clarity, the index of **Time step** and **N° generator** starts at 0. For the data **Type of bid**, the value 1 describes a flexible bid and the value 2 describes a block bid. Two other variables are forwarded thanks to this file : the index of the day, which also starts at 0 and the number of bids in this file.

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