Remuneration of Flexibility using Operating Reserve Demand Curves: A Case Study of Belgium

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ABSTRACT

Flexibility is becoming an increasingly important attribute of conventional generators due to the challenges imposed by the unpredictable, highly variable and non-controllable nature of renewable supply. Paradoxically, flexible units are currently being mothballed or retired in Europe due to financial losses. We investigate an energy-only market design, referred to as operating reserve demand curves, that rewards flexibility by adjusting the real-time energy price to a level that reflects the value of capacity under conditions of scarcity. We test the performance of the mechanism by developing a model of the Belgian electricity market, which is validated against the historical outcomes of the market over a study period of 21 months. We verify that (i) based on the observed market outcomes of our study period, none of the existing combined cycle gas turbines of the Belgian market can cover their investment costs, and (ii) the introduction of price adders that reflect the true value of scarce flexible capacity restores economic viability for most combined cycle gas turbines in the Belgian market.

Keywords: Flexibility, Energy-only markets, Renewable integration, Operating reserves, Capacity remuneration, Unit Commitment

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1. INTRODUCTION

The remuneration of flexible capacity is a growing challenge of electricity market design. This paper investigates the extent to which an economically justified remuneration of reserve capacity through operating reserve demand curves (ORDC) could provide the needed support for keeping the flexible capacity in the system. Operating reserve demand curves were introduced by Stoft (2002) and advocated by Hogan (2005) in order to support the remuneration of capacity in restructured US electricity markets. This paper explores the possible application of ORDC in a European context, taking Belgium as an example.

We concentrate on reserves for guaranteeing security of supply in the case of contingencies and net load forecast errors. The recent proliferation of renewable resources has led to scrutiny over the appropriateness of fixed reserve requirements, as opposed to dynamic reserve criteria that reflect the real-time conditions of the system (Papavasiliou and Oren, 2013). We remain in this context as ORDC values reserve as a function of real-time conditions of the system but we address a longer term economic problem: we want to assess whether the integration of renewable resources shifts a sufficient amount of value from energy markets into reserve markets, such that flexible units providing reserves earn sufficient revenue to ensure their economic viability. Such a finding may require new market mechanisms for capturing this value and organizing its transfer to flexible plants. These mechanisms should naturally be dynamic and reflective of the real-time conditions of the system, which justifies the consideration of ORDC.

1.1 Some milestones of the literature

Shanker (2003) coined the word "missing money" that became the basis of most discussions on insufficient investment in generation: there is missing money when the market insufficiently remunerates a service or a commodity. Stoft (2002) provided the basic reasoning on payment for reliability while Hogan (2005) and Joskow (2007) offered comprehensive analysis of the problem. Their discussions were mainly in terms of missing money, but a related notion, namely that of a missing market (Newbery, 1989), also briefly appears in Hogan (2005): there is a missing market when there is no market for a scarce service or commodity. This distinction between missing market and missing money is particularly important in issues related to renewable energy integration (Newbery, 2015), but it can also be used to structure the early debates that led to the dichotomy between energy-only (EO) and capacity remuneration mechanisms (CRM) in investment. In missing money terms, power exchanges based on short-run marginal cost bidding insufficiently remunerate energy, leading to a shortage of generation capacity. The remedy is then to adapt the energy market to improve the remuneration. The alternative CRM view, commonly described in terms of missing money but possibly better interpreted through missing markets, follows an old engineering tradition: energy and capacity are different things and there is no market for capacity in the power exchange. The remedy is thus to introduce a market for capacity or to directly remunerate capacity. The two paradigms have been extensively explored in the literature. Cramton et al. (2013) gives an in-depth analysis of these economic alternatives; Spees et al. (2013) and Bowring (2013) report experiences in real systems. Consultants extensively intervened in the debate and have sometimes also reported their findings in academic circles (e.g. (Pfeifenberger et al., 2014)). Lastly, one should also mention Bhagwat et al. (2016), who summarize the US experience in terms of lessons for Europe.

The European context indeed added a new dimension to the problem of capacity remuneration. Cross-border trade is an essential element of EU energy policy and the adoption of different CRMs in Member States could distort this trade. As discussed later in the paper, this is a concern for competition authorities, in particular the Directorate General for Competition of the European Commission (DG COMP). Finon and Roques (2013) provide a methodological analysis focused on Europe, while Thema et al. (2013) report the variety of situations encountered in Europe and the types of problems that these situations raise in the internal electricity market (IEM). Newbery (2015) provides a thorough discussion of the UK process that led to a capacity market accepted by DG COMP. Eurelectric (Lopes and Lorens (2015)) reacted to the position of DG COMP, insisting on the need to implement capacity mechanisms: the organization recommended cross-border mechanisms without really elaborating on how this would be done. Agora Energiewende also extensively published on the subject: (Agora-Energiewende, 2013a) is an introduction to its positions. Other more ad hoc tools such as strategic reserve are also found in practice (Agora-Energiewende, 2013b). They are documented in the profession but have not received much attention in the economic literature. While the discussion on energy-only markets versus capacity remuneration mechanisms belongs to the early but still active literature and practice, the remuneration of flexibility of different types (traditional reserve, longer term ramping, voltage support) is progressively becoming an important subject in the era of large-scale renewable energy integration. As argued and illustrated in the paper, ORDC offers some hope to embed these aspects in the energy-only market without adding new capacity products (such as ramping).

1.2 Capacity Markets versus Energy-Only Markets in the European Context

Beyond the public good character of reserve, which complicates the provision of an appropriate level of security, electricity markets struggle inherently with supporting capacity investment due to several market failures. In theory real-time prices should be sufficient to reflect the value of scarce flexible capacity, lending support to the notion of energy-only markets. The principle is that real-time deviations for power balance will induce changes in equilibrium prices; agents that are flexible enough to respond to such changes immediately will be rewarded for supporting the system through their reaction. The issue is to have a market design that conveys these principles in practice. The closest design to the theoretical ideal of real-time energy-only markets is value of lost load (VOLL) pricing (Stoft, 2002), where provision is rationed randomly under conditions of scarcity and the price is set to an administratively determined estimate of VOLL. However, VOLL pricing raises issues in terms of estimation of the VOLL itself, uncertainty in the frequency of price spikes, and regulatory uncertainty in its implementation, with the result that energy-only markets are sometimes viewed as a perilous investment environment.

Capacity payment mechanisms are the usual contenders of energy-only markets. In analogy to fixed reserve requirements that represent a static approach towards ensuring security of supply, capacity markets in their simplest form could be interpreted as a static economic mechanism for supporting flexible capacity. Even though capacity mechanisms are generally perceived as providing more reliable investment signals, as opposed to the volatile price spikes of energy-only markets with inelastic demand, capacity markets typically fail to differentiate resources sufficiently with respect to flexibility; the determination of capacity targets is often contestable and non-transparent and capacity markets have been criticized for suppressing economic signals for proliferating demand response.

Levin and Botterud (2015) provide an up-to-date classification of scarcity mechanisms and capacity markets that are utilized by the eight major electricity market operators in the United States (CAISO, ERCOT, ISO-NE, MISO, NYISO, PJM and SPP). We focus on the European context where the renewable integration targets of the European Commission (EC, 2009a), the goal of a common Internal Electricity Market (EC, 2009b), and the subsequent lack of incentives to invest (except in subsidized technologies) has induced Member States to create various capacity remuneration mechanisms that DG COMP has viewed as sources of distortion of competition in the internal electricity market. Capacity remuneration mechanisms are criticized as balkanizing the European market design[1], whereas energy-only markets are perceived as being more in line with market coupling and a common design for the European energy market. DG COMP therefore sees capacity mechanisms as exceptional measures aimed at mitigating shortage of capacity in particular situations: they should not be seen as generic remedies to a market failure but at best as corrections to a temporary phenomenon and justified accordingly. Following up on that idea, DG COMP launched a Sector Inquiry to document the market mechanisms implemented or planned in 11 Member States. An interim report (EC, 2016) confirms the position of DG COMP that capacity mechanisms in Europe contain significant parts of prohibited State Aids and that an energy-only design should be the preferred option. This paper introduces ORDC in this policy discussion through an assessment of its impact in Belgium. The core of the paper is devoted to the discussion of the concepts and the application to Belgium, with the conclusions casting these findings in the general European policy discussion.

1.3 Operating Reserve Demand Curves

In order to overcome the challenges associated with energy-only markets and capacity mechanisms, Hogan proposes a correction of energy prices that reflect the true value of flexible capacity (sufficiently flexible to provide operating reserve) that stems from reducing the loss of load probability in real time (Hogan, 2005), (Hogan, 2013). The proposed mechanism is motivated by an effort to align the valuation of reserve capacity with the operating practices of system operators. The value of operating reserve capacity stems from its ability to decrease the probability of lost load.

Economically, energy and reserve prices are linked by an arbitrage which equalizes the price for reserves to the opportunity cost of keeping reserve capacity out of the energy market. An abundance of capacity (besides the one required for ensuring full reliability) at some moment in time would imply a zero value for marginal capacity for reserve. In contrast, scarce reserve has a non-zero value that should modify the energy price set by the marginal plant in order to induce some capacity of that plant to move to reserve. The price of reserve should thus vary according to the level of operating reserve capacity that is available in the system at any time. Given this arbitrage relationship between energy and reserves, energy prices should reflect the scarcity value of reserve. This is what the ORDC does by setting the real-time price of electricity at a level that ensures that a price-taking agent offering energy and reserve capacity would, in equilibrium, dispatch its unit according to a

[1]European markets are currently organized as follows (CREG, 2012): (i) Energy-only markets are in place in Belgium, Germany, the Netherlands, and Great Britain; (ii) capacity payments are instituted in Spain, Portugal and Ireland; (iii) capacity requirements are imposed in Sweden and Finland; (iv) France is transitioning from an energy-only market to a decentralized capacity market.

socially optimal schedule. This instantaneous valuation of capacity available for energy and reserve should reflect (and thus ideally replace in an energy-only market) the need for the ex ante valuation of capacity in capacity markets.

The proposed design has been adopted in the Electric Reliability Council of Texas (ERCOT) without co-optimization of energy and reserve by the ISO, and generated notable revenue in the summer of 2015. The correction to the energy price is computed after the clearing of the energy market and is thus an adder to the energy price. The mechanism has also been tested and is currently operational in a number of other US markets with co-optimization by the system operator, including the New York ISO, the ISO New England, the Midwest ISO, and the Pennsylvania-New Jersey-Maryland (PJM) market (Hogan, 2016). Because reserve and energy are co-optimized, we refer to this market design as one where the energy price is marked up.

US and EU markets are not designed in the same way and a first question is whether ORDC can be implemented in the EU electricity market design where the power exchange is cleared independently of reserve. In a US-style market design where energy and ancillary services are cleared simultaneously in real time by an Independent System Operator, the proposed adjustment to the energy price could either be added ex post as an approximation to the real-time energy price (as is currently the case in Texas), or the system could be dispatched in real time with the operating reserve demand function included in the objective function. Because both balancing and reserve are the responsibility of Transmission System Operators, this mechanism could be implemented in European balancing markets to accurately signal the real-time conditions of the system; this would maintain the existing structure of these markets. However, two features of the European market would have to be reconsidered. The European balancing market should function as a two-settlement system whereby balancing responsible parties should be able to deviate from their schedule and receive the balancing price for their deviation. In addition, the value of scarce capacity needs to be propagated to earlier stages. This issue is rather subtle (it appears in US market design in the context of discussions about the role of the day-ahead market as a forward market (Parsons et al. (2015)) and is left for further investigations.

1.4 Research Goal and Outline

Belgian power production capacity connected to the regular grid amounts to 14765 MW. Between September 2014 and mid-October 2014, four nuclear units in the Belgian system were retired from service simultaneously due to technical malfunctions, amounting to a total unplanned outage of approximately 4000 MW. In light of these events and the paradoxical retirement and mothballing of flexible capacity in Belgium, the Belgian Regulatory Commission for Electricity and Gas (CREG) issued an investigation about whether adequate incentives are in place in order to attract investment in flexible power generation in the country. The question that is addressed in this study is how electricity prices in the Belgian market would be impacted if ORDC price adders were introduced in the market.

The paper is structured as follows. In section 2 we describe the methodology that we have used for conducting our analysis. In section 3 we present a model of the Belgian electricity market, which is validated against 21 months of historical observations of the Belgian market. In section 4 we present the results of our analysis. In section 5 we conclude and discuss directions of future research.

2. METHODOLOGY

In this section we first provide a detailed exposition of the idea of operating reserve demand curves. We then outline the organization of our study. We end the section with a description of the Belgian electricity market.

2.1 The Idea of Operating Reserve Demand Curves

The ORDC is a real-time mechanism where the decision is to be made of optimally trading off the allocation of capacity between the provision of energy and the protection of the system against uncertain shortfalls in available capacity. The basic model that motivates the proposed mechanism can be described as a two-stage stochastic program (Hogan, 2013). Consider a probability space $(\Omega, \mathcal{F}, f)$ consisting of a set of outcomes Ω and a discrete probability measure f. The set of outcomes represents the uncertainty faced by the system operator due to unanticipated net demand fluctuations and contingencies. As the name suggests, ORDC is intended as a remuneration mechanism for operating reserves that can respond to contingencies or abrupt net demand changes, rather than regulating reserves. The model (dual variables are listed on the left side) is stated as:

$$\max \int_{x=0}^{d} MB(x)dx - \sum_{g \in G} \int_{x=0}^{p_g} MC_g(x)dx + \sum_{\omega} f_\omega \cdot (VOLL \cdot \delta_\omega - \hat{MC}(\sum_g p_g) \cdot \delta_\omega) \quad (1)$$

$$\text{s.t.} \quad (\lambda): \quad \sum_g p_g \geq d \quad (2)$$

$$(\mu_\omega): \quad \sum_g r_g \geq \delta_\omega, \forall \omega \in \Omega \quad (3)$$

$$(\rho_g): \quad p_g + r_g \leq P_g, \forall g \in G \quad (4)$$

$$(\gamma_\omega): \quad \delta_\omega \leq \Delta_\omega, \forall \omega \in \Omega \quad (5)$$

$$p_g, r_g, d, \delta_\omega \geq 0 \quad (6)$$

where Δ_ω corresponds to the additional demand that appears under outcome ω and δ_ω corresponds to the amount of Δ_ω that is actually served. The derivative of the variable cost of generator g is indicated by $MC_g(p_g)$. The function $\hat{MC}$ is introduced by Hogan (2013) as an approximation of the incremental cost of operations for meeting an additional increment of demand. For example, one could employ the marginal cost of an unconstrained system, i.e. a system where transmission constraints are ignored.

The decision variable r_g corresponds to the amount of reserve provided by a generator. The marginal benefit of consumers is represented by a decreasing function $MB(\cdot)$, with d corresponding to the power consumption of loads.

Assuming an interior solution for a marginal generator ($p_{g_m} > 0$ and $r_{g_m} > 0$ for some g_m), one obtains from the KKT conditions

$$\begin{aligned} \lambda &= MC_{g_m}(p_{g_m}) + \sum_\omega f_\omega \hat{MC}'(\sum_g p_g)\delta_\omega + \rho_g \\ &= MC_{g_m}(p_{g_m}) + \sum_\omega f_\omega \hat{MC}'(\sum_g p_g)\delta_\omega + \sum_\omega \mu_\omega \end{aligned} \quad (7)$$

The following cases can now be considered for a given contingency ω: either (i) the amount of committed reserve does not suffice for covering the net load deviation, $\Delta_\omega > \sum_g r_g$, or (ii) the reserved capacity suffices for covering the demand deviation, $\Delta_\omega < \sum_g r_g$. As a technicality, consider also the degenerate case (iii) where the reserved capacity exactly covers the demand deviation, $\Delta_{\omega_0} = \sum_g r_g$ (this possibility corresponds to a single outcome, which is denoted ω_0 where both

$\sum_g r_g \geq \delta_\omega$ and $\delta_\omega \leq \Delta_\omega$ hold as equalities). In the first case, since $\delta_\omega < \Delta_\omega$ we conclude that $\gamma_\omega = 0$. In the second case, since $\delta_\omega < \sum_g r_g$ we conclude that $\mu_\omega = 0$, while $\mu_{\omega_0} \geq 0$ and $\gamma_{\omega_0} \geq 0$ in the third case. This yields

$$\sum_\omega \mu_\omega = \sum_{\omega:\Delta_\omega \geq \sum_g r_g} \mu_\omega - \gamma_{\omega_0} \tag{8}$$

Given that $\delta_\omega > 0$ for every realization, the KKT conditions give $\mu_\omega + \gamma_\omega = f_\omega(VOLL - \hat{MC}(\sum_g p_g))$. Case (iii) is degenerate in the sense that we can select any non-negative value of μ_{ω_0} and γ_{ω_0} satisfying $\mu_{\omega_0} + \gamma_{\omega_0} = f_{\omega_0}(VOLL - \hat{MC}(\sum_g p_g))$. Selecting $\mu_{\omega_0} = f_{\omega_0}(VOLL - \hat{MC}(\sum_g p_g))$ we obtain

$$\begin{aligned}\sum_\omega \mu_\omega &= \sum_{\omega:\Delta_\omega \geq \sum_g r_g} f_\omega(VOLL - \hat{MC}(\sum_g p_g)) \\ &= LOLP(\sum_g r_g) \cdot (VOLL - \hat{MC}(\sum_g p_g)),\end{aligned} \tag{9}$$

where $LOLP(R) = \mathbb{P}[\Delta_\omega > R]$ is the loss of load probability given reserve level R, i.e. the probability that an unforeseen shortfall in capacity or increase in demand exceeds the level of reserves. Substituting back to equation (7), and ignoring the term $\sum_\omega f_\omega \hat{MC}'(\sum_g p_g)\delta_\omega$ due to its second order effect (for example, the term vanishes if at the optimal solution the marginal cost is constant), we obtain

$$\lambda = MC_{g_m}(p_{g_m}) + (VOLL - \hat{MC}(\sum_g p_g)) \cdot LOLP(\sum_g r_g). \tag{10}$$

The first term of the expression corresponds to the equilibrium competitive price that is obtained by an energy-only dispatch that ignores reserve. The second term, referred to hereafter as a price adder, corresponds to a price lift that quantifies the value of scarce reserve capacity. This adder indicates how the energy price should be adjusted if individual generators were to voluntarily replicate the socially optimal allocation of their capacity among energy and reserves.

Reserve products are imperfectly substitutable, with faster reserve capacity being capable of covering multiple reserve products. The methodology presented above can be applied for computing price adders that align incentives in an auction that clears multiple substitutable reserves. Consider reserves with response times $T_1 = \Delta_1 < \Delta_2 = T_1 + T_2$, and suppose that a total reserve capacity of R_{Δ_i} can be made available by time Δ_i. Then it can be shown (Hogan, 2013) that, as long as the pivotal unit has not exhausted its ramp capacity for response time Δ_1, the ORDC price adder needs to be adjusted as follows:

$$\lambda = MC_{g_m}(p_{g_m}) + \frac{T_1}{T_1 + T_2}(VOLL - \hat{MC}(\sum_g p_g)) \cdot LOLP_{\Delta_1}(R_{\Delta_1}) + \frac{T_2}{T_1 + T_2}(VOLL - \hat{MC}(\sum_g p_g)) \cdot LOLP_{\Delta_2}(R_{\Delta_2}), \quad (11)$$

where the loss of load probability $LOLP_{\Delta_i}$ is adjusted for the horizon at which the reserve can be delivered, with a deeper time horizon corresponding to greater uncertainty.

2.2 ORDC and EU Market Design

The design of the EU market differs in several aspects from the US system for which the ORDC was proposed. This section briefly discusses some issues that we think are important for the analysis. The organization of transmission and the role played by the day-ahead market are the two major divergences between the US and EU systems. We disregard transmission constraints that are somewhat marginal to ORDC and concentrate on the day-ahead market. We first compare the role of ORDC in the US and EU organizations and then elaborate on the clearing of the market. Variations between ISOs in the US are incidental for our purpose and can be neglected.

2.2.1 Single- and Two-Settlement Systems

The US restructured power market is a two-settlement system with added virtual trading. The underlying idea is that there should be a forward market in the day ahead and a spot market in real time. Because of different constraints applying in these two stages, virtual trading is introduced to enable arbitrage between them. ORDC is meant to measure the scarcity of reserve in real time and hence should apply in the real-time market, based on machine availability for energy and reserve determined by the unit commitment.

The EU market is structurally a single-settlement market cleared in the day ahead (we do not discuss the intra-day market, which remains insufficiently researched to date). Balancing takes place in real time but is conceived as a correction mechanism; its organization differs from the one of the day-ahead market, and balancing cannot be seen as a spot market following a forward day-ahead market. We argued before that ORDC should be implemented with balancing restructured as the second stage of a two-settlement system. Our analysis assumes that ORDC is implemented in real time, seen as a true market that signals the scarcity of capacity in the EU market design using the machine availability for energy and reserve determined before real time. The question is then to simulate this market.

2.2.2 Market Clearing

As explained previously, the adder requires knowing the term $\hat{MC}(\sum_g p_g)$ and the amount of reserve R_Δ that can be made available within a time interval Δ. Because we are interested in prospective information, we also wish to be able to conduct the analysis on the basis of a model that can be run under different scenarios. The following motivates our modeling approach on the basis of a comparison of US and EU market clearing in the day ahead.

Generators are subject to indivisibilities (startup and shutdown cost, minimal duration between startup and shutdown, and so on), of which the importance is growing with the penetration of renewable resources. It is well known that there cannot be any true market clearing in the presence of indivisibilities in the sense that one cannot guarantee the existence of linear prices that balance supply and demand. This applies to both the US and EU with the consequence that none of these day-ahead markets clears in the strict sense of the term (even though we retain the term "clearing" for convenience). The unit commitment model is central to market clearing in the US where the ISO simultaneously clears the day-ahead energy and reserve markets on the basis of offers describing economic and technical characteristics of the machines. This produces an efficient (least cost or welfare maximizing) schedule. Because of indivisibilities this schedule cannot in general be supported by a linear price system. This means that dual variables of either the linear or convex hull relaxations of the UC give prices that do not fully support all the efficient dispatch schedules. Uplifts that make whole those generators that should be part of the efficient dispatch but are not supported by the associated price system correct the situation. All generators that are part of the efficient dispatch are thus incentivized to remain in the system. This process, and hence the introduction of ORDC in this process, is easy to model, at least in principle: it entirely relies on a unit commitment model, which is a well-known instrument in the profession.

The EU separates the energy and reserve markets into an energy market cleared by a Power Exchange and a reserve auction conducted by the TSO. This means that generators need to arbitrage their allocation of capacities between the energy and reserve markets. This is a first difference with the US where this arbitrage is conducted by the unit commitment. A second difference is that the clearing of the energy market is not made on the basis of bids involving energy costs and machine characteristics. The EU organization requires that generators internalize these machine characteristics into energy bids subject to logical constraints (e.g. all-or-nothing bids). These are referred to as block bids. The clearing of the EU energy market thus takes place over a mix of flexible bids (without logical constraints) and block bids (with logical constraints). This clearing could be done by a mixed integer program as for the security constrained unit commitment, but again this is not what the rules of the power exchange require. A special purpose mixed integer algorithm (EUPHEMIA) clears the energy market by searching for the mix of flexible and block bids that (i) maximizes welfare (or equivalently, here, minimizes cost), (ii) satisfies demand, subject to the additional constraints that (iii) there exist linear prices clearing the retained flexible bids and (iv) all the retained block bids are in the money at those prices. Parts (i) and (ii) that deal with quantities are similar to what the unit commitment produces, except that the model is formulated in flexible and block bids. Parts (iii) and (iv) are unusual: they are meant to produce something that resembles linear market-clearing prices. As this is impossible, EUPHEMIA also generates an undesired by-product: block bids that are in the money but in excess of what is efficient to satisfy demand. These are referred to as "paradoxically rejected bids". Notwithstanding the computational sophistication of the method, the EU market design leads to a degradation of the overall welfare compared to a US solution because of the need to transform machine characteristics into block bids and the unusual price constraint in the welfare maximization. This also means that the application of ORDC in the EU system is not as straightforward: the commitment of capacities and their allocation between energy and reserve are not directly coming from a unit commitment model, as we discuss next.

2.3 Implication for the Study

The principles underlying EUPHEMIA are well documented in the professional and academic literature and the algorithm can be programmed relatively easily by external parties on the basis of that information. In contrast, the internalization of technical constraints in terms of block bids as well as the allocation of their capacities between the energy and reserve markets (recall the separation of energy and reserve in the EU design) are by nature inaccessible to outside parties. Strictly speaking, it is thus impossible to reproduce the functioning of the market. One can however argue that EUPHEMIA, by trying to maximize welfare, pursues the same objective as the cost minimization of the unit commitment. Similarly, one could conjecture that good practitioners should have found some way to construct meaningful block bids. As to the separation of the capacity into energy and reserve, one can also invoke the usual economic assumption that agents properly arbitrage between them. In short, except for the price constraints in the enumeration, EUPHEMIA tries to reproduce what an integrated (energy and reserve) unit commitment does. We thus make the bold conjecture that a pure unit commitment used to allocate capacity to reserve and energy and operating on the basis of the technical description of the machines could be a reasonable approximation to market observation. Needless to say this conjecture must be validated. This is the purpose of the validation component of our analysis.

The situation is quite different for prices. The use of the unit commitment to clear the market in the US leads to a price system that does not induce enough generation and hence requires some additional action through uplift. In contrast, EUPHEMIA by construction leads to a price system that leads to excess generation (just the opposite of a price system derived from the UC) and needs to dispose of some generation in the form of paradoxically rejected bids. By construction, EUPHEMIA is not driven by the objective of reproducing prices similar to those that could be extracted from a UC. As we shall see it is effectively necessary to construct a separate model that mimics the construction of the price system by EUPHEMIA. This is the model presented in section 6.3 of the appendix.

2.4 Proposed Methodology

Notwithstanding these differences between the US and EU system, the goal of our study remains to determine how the introduction of ORDC could impact the remuneration of flexible plants in the Belgian electricity market. As indicated in equations (10) and (11), this requires (i) knowledge of the marginal cost of the marginal unit $\hat{MC}(\sum_g p_g)$ in the real-time market, (ii) quantifying the net load uncertainty which the system faces within a given time horizon Δ in order to compute the function $LOLP_\Delta(\cdot)$, and (iii) quantifying the amount of reserve R_Δ that can be made available within a time horizon Δ.

The data that was provided for the study includes day-ahead and real-time prices of the Belgian market, hourly production *by fuel* in both the day-ahead and real-time market, demand in the day-ahead and real-time market, the amount of activated reserve energy (instead, the amount of reserve capacity provided by each unit or the amount of activated reserve energy *by unit* is not available), production capacity available *by fuel*, and imports/exports in the day ahead and in real time over each interconnection.

The term $\hat{MC}(\sum_g p_g)$ is estimated in our analysis by the real-time price. The net load uncertainty within a fifteen-minute horizon is estimated based on the amount of activated reserve energy[2]. A normal distribution is fit to the net load uncertainty in order to obtain the function

[2]Provided there is no involuntary load shedding, activated reserve energy corresponds to the net load deviation in real

$LOLP_\Delta(\cdot)$, as explained in section 4.1. The major challenge was to estimate the amount of capacity R_Δ that is available in real time within a time horizon Δ. This capacity depends on the ramp rates of the specific units that were actually committed at each given hour of the study. This data was not available to us explicitly. We deduce this information by using the data that was provided to us in order to build a bottom-up model of the Belgian electricity market. The Belgian market model that we develop is validated against the data that was provided to us by comparing its predictions to the actual *day-ahead* market-clearing price and market-clearing quantity of the Belgian market for the duration of the study. The day-ahead and real-time net demand faced by thermal units over the duration of the study exhibit a mean absolute error of 172 MW, which indicates that the day-ahead unit commitment decisions should be close predictors of the units that actually operate in real time[3]. Therefore, by being able to develop a model that closely emulates the outcomes of the Belgian day-ahead electricity market we are able to deduce the individual units that were actually on-line in real time over the duration of the study. This information is then adequate for inferring the amount of reserve capacity that would be available within a time interval Δ, thus enabling us to estimate the ORDC price adder. Previous research on ORDC either ignores individual unit ramp constraints (Levin and Botterud, 2015) (which, we argue, may greatly influence the resulting adder), or applies the analysis without previously calibrating the market model to actual market outcomes (Zhou and Botterud, 2014).

The methodology is explained in further detail in figure 1. The validation process of the Belgian market model is indicated in the left part of the figure, while the simulation of the Belgian market in order to determine price adders is indicated in the right part of the figure. Details about each part of the analysis are provided in the paragraphs that are indicated by figure 1.

The Belgian market model that we develop is based on a unit commitment and dispatch model[4] which is presented in section 6.1 of the appendix. Once our market model is calibrated, we validate it by comparing its ability to explain observed market prices and cleared quantities to competing approaches. The competing approaches are developed in detail in section 3.2.1 (for explaining observed quantities) and section 3.2.2 (for explaining observed prices).

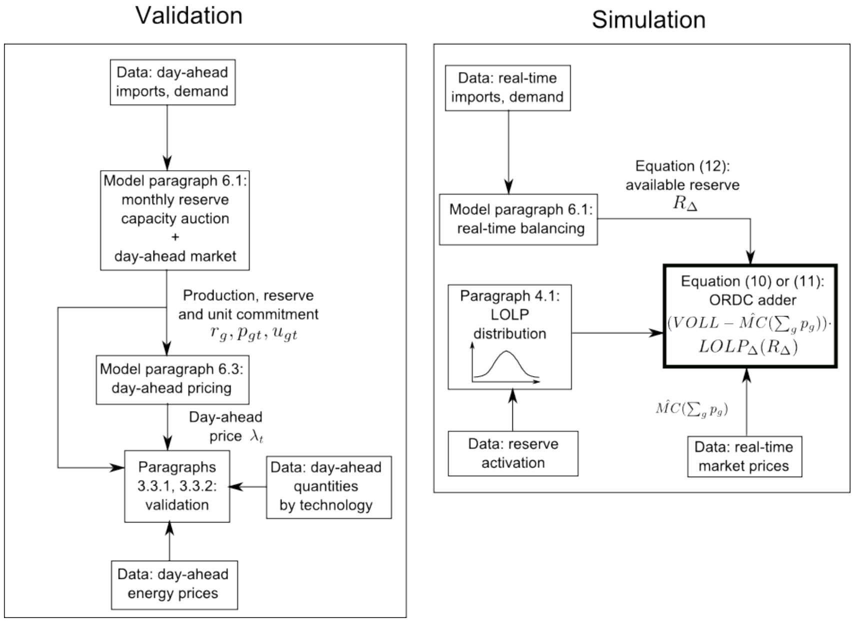
A successful validation of our model against Belgian market data would imply that the model

time, otherwise it is an under-estimate of net load deviation. Given that involuntary load shedding is rare in Belgium, activated reserve energy is chosen as an accurate proxy of net load deviation.

[3]Note that the smallest CCGT units in the Belgian market have a capacity of 350 MW. This suggests that a mean absolute error of 172 MW between day-ahead and real-time net demand is unlikely to result in a significant reshuffling of the thermal fleet from day-ahead to real-time operations. In case of increasing renewable energy integration, the role of intra-day markets in adjusting the position of the thermal fleet would be expected to become more important, in which case a validation of a candidate market model against day-ahead market historical performance might be less meaningful.

[4]Note that although the market model is presented in a decentralized format, it is solved as a coordinated optimization problem using the solution methodology of section 6.2.

Figure 1: A schematic diagram of the proposed methodology. The left block indicates the validation of the market model.



could also be used for examining the impact of ORDC in a prospective study for future conditions of the system[5]. As indicated in figure 1, such an analysis would require, as exogenous input, a forecast of real-time system demand and imports (which could be part of the definition of the scenarios of a prospective study). The computation of $\hat{MC}(\sum_g p_g)$ in the context of a prospective study is of minor importance since $VOLL$ tends to exceed $\hat{MC}(\sum_g p_g)$ by at least one order of magnitude, thereby rendering $VOLL \cdot LOLP(R_\Delta)$ as an acceptably accurate approximation of the ORDC adder in equation (10).

Note that this is an open-loop analysis, i.e. we do not account for how the expectation of introducing ORDC feeds back into the capacity that is deployed in the market. A closed-loop analysis will be the subject of future investigation.

2.5 Salient Features of the Belgian Market

The Belgian day-ahead energy market is organized as an exchange and clears power independently of reserves. Belgium participates in the Central Western European (CWE) energy market. Until May 2015 (this includes the interval of time studied in this paper), transmission constraints were represented in the exchange using a transportation model that ignores intra-zonal congestion as well as

[5]For example, how would the ORDC be influenced if nuclear units were to be restored in service in the Belgian market?

the physical constraints imposed by Kirchhoff's voltage laws and produce loop flows[6]. The exchange clears at a uniform zonal price. Two types of bids can be submitted to the exchange. Continuous bids correspond to a price-quantity pair for each hour, and clear according to standard rules for uniform price auctions (i.e. bids that are in the money are accepted entirely, bids that are out of the money are rejected entirely, and bids that are on the money may be partially accepted). Block bids correspond to production profiles over the *entire day* and are associated with a bid cost. These bids are intended to represent unit commitment costs and constraints, and are either entirely accepted or entirely rejected. According to the rules of the CWE exchange, block bids may be paradoxically rejected (i.e. they may be rejected even though the clearing price would result in a positive profit for the schedule of the bid), but may not be paradoxically accepted (i.e. no schedules that would result in negative profits may be accepted, even if they increase welfare). The exchange seeks a primal-dual market clearing solution that maximizes welfare and respects the aforementioned rules.

Reserve capacity in the Belgian market is cleared in annual and monthly pay-as-bid auctions for reserve capacity. Reserve in Belgium is classified in three categories[7]. Primary reserve responds immediately to changes in frequency resulting from instantaneously supply-demand imbalances. Secondary reserve reacts within a few seconds, and is expected to provide full response in seven minutes. Tertiary reserve should be made available within fifteen minutes after being called upon.

Every resource in the Belgian market is associated with a balancing responsible party. Balancing responsible parties are required to balance their portfolios in real time. The Belgian balancing market settles real-time deviations of balancing responsible parties. An important feature of the balancing market is that resources that are cleared in the reserve capacity markets are *required* to bid in the balancing market, i.e. they are not allowed to opt out. The balancing market is cleared through merit order dispatch. Inter-zonal congestion is not accounted for in the present study and is not discussed further here. This assumption is largely justified by the fact that the Belgian TSO resorts to active transmission elements (line switching, phase shifters, etc.) as a first line of defense against internal congestion, and limits the re-dispatch of units to the greatest possible extent in order to avoid the associated cost.

[6]Flow-based market coupling was introduced in May 2015 with the goal of representing transmission constraints more accurately during the clearing of the market.

[7]Each of these three categories includes further sub-categories, this is ignored in order to keep the exposition clear.

3. MODELING THE BELGIAN ELECTRICITY MARKET

In this section we discuss the calibration of our model, and the validation of our model against historical outcomes of power production and price realizations.

3.1 A Model of the Belgian Market

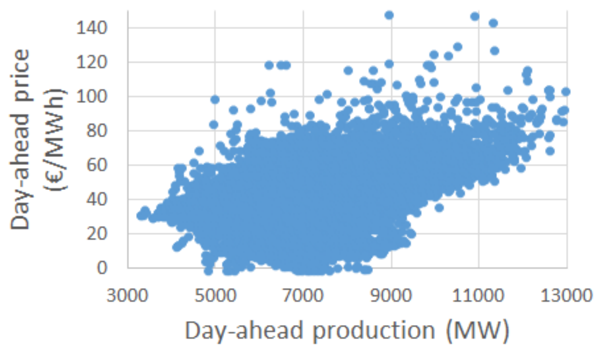
The study presented in this paper is conducted over a period of 21 months, covering the interval from January 2013 until September 2014. The model proposed in this section is driven by the availability of data. Agents are classified into different categories, based on how they interact with the market-clearing price. The data is characterized by hourly resolution. This data includes day-ahead and real-time prices, hourly production *by fuel* in both the day-ahead and real-time market, the amount of activated reserve energy (instead, the amount of reserve capacity provided by each unit or the amount of activated reserve energy by unit is not available), production capacity available *by fuel*, demand in the day ahead and in real time, and imports/exports in the day ahead and in real time over each interconnection[8]. A non-public, commercial database is used for obtaining unit-by-unit technical and economic data for coal and combined cycle gas turbine (CCGT) units. Average prices for reserve capacity in the study interval are also available from publicly available studies[9]. Unit-by-unit outages (scheduled as well as unscheduled) are publicly available at the website of the Belgian transmission system operator. The price of carbon dioxide is obtained from the Intercontinental Exchange. Estimates for emissions rates are obtained from the Energy Information Agency. The price of coal is obtained from a non-public commercial database. The available transfer capacity of the interconnectors linking Belgium to France and the Netherlands is retrieved from the transparency platform of the European network for transmission system operators.

The market model proposed in this section can also be used to analyze the notable dispersion between production and the day-ahead market clearing price, presented in figure 2. The observed correlation between market clearing price and the quantity of dispatched power is expected to be positive since price-quantity observations are expected to lie on the marginal cost function of the technology in question, which is normally increasing. What is surprising in the scatter plot of figure 2 is the degree of dispersion in the price-quantity observations. The following factors are conjectured

[8] An interconnection is a corridor linking the Belgian market to its neighboring markets, namely France and the Netherlands. A 1000 MW interconnection of Belgium to the United Kingdom has been commissioned in February 2015.

[9] See *Potential Cross-Border Balancing Cooperation between the Belgian, Dutch and German Electricity Transmission System Operators*, October 8, 2014.

Figure 2: A scatter plot of day-ahead production versus day-ahead price in the Belgian market, January 2013 - October 2014.



to contribute to the observed variability: (i) outages, (ii) costs and constraints associated to unit commitment, (iii) imports and exports, (iv) reserve requirements, (v) distributed renewable supply that is not metered[10], (vi) pumped storage resources, (vii) combined heat and power, and other must-take resources, (viii) fuel price fluctuations, and (ix) market power. By contrast, forward and bilateral commitments of market participants and demand-side bidding are discarded as possible causes of the observed dispersion. Forward commitments should not bind efficient real-time decisions, and demand-side bidding simply produces an observation of the market-wide supply function at a different price-quantity pair.

3.1.1 Generators

Generators are classified into three categories, depending on their responsiveness to market price: (i) inelastic resources, (ii) dispatchable resources, and (iii) committed resources. We proceed with an explanation of each type.

Inelastic resources are resources the output of which is not driven by electricity prices, either because the marginal cost of these resources is such that they are always dispatched, or because these are must-take resources. This includes nuclear power (6032 MW), wind power (864 MW), waste (259 MW), and water (101 MW). The production of inelastic resources is fixed to its historical value.

Dispatchable resources are aggregated resources the production of which is driven by market price. This includes blast furnace (350 MW), non-wind renewable resources (106 MW), gas-oil (82 MW), and turbojet (213 MW). These resources are characterized by an affine marginal cost function

[10]Prior to October 31, 2014, decentralized generation injecting below 30 kV was not accounted for in the measurement of Belgian net load. The significance of distributed generation has steadily increased during the last years. Since November 2014, the Belgian System Operator forecasts net Belgian electric load by accounting for distributed supply. Given the interval of the study presented in this paper, this factor influences our analysis.

with a non-zero intercept. The marginal cost function is static, and estimated using least squares. The capacity of these resources is time-varying, and captures the effect of scheduled or unplanned outages. The model of these resources is provided in the appendix.

Committed generators are resources described by a unit commitment model, the technical and economic data of which is available by unit. This corresponds to coal (972 MW) and CCGT (6506 MW). The representation of these resources through a unit commitment model is necessary for understanding the behavior of electricity prices in the Belgian market, as explained subsequently. An approximation of these resources through a convex model, such as the one developed for dispatchable resources, was attempted and resulted in a highly inaccurate approximation of the observed market behavior.

The model of committed resources is presented in the appendix. The model accounts for (i) technical minimum, (ii) scheduled and unscheduled outages through a time-varying technical minimum and maximum production limit, (iii) time-varying fuel cost, (iv) ramp rates, (v) minimum up and down times, (vi) startup cost, (vii) minimum load cost, and (viii) a multi-segment marginal cost curve. Committed generators are assumed capable of providing primary, secondary, and tertiary reserve. Committed generators include a separate term for the marginal cost for carbon emissions. Instead, for dispatchable generators this marginal cost is embedded in the calibrated linear supply function.

3.1.2 Pumped Storage

A pumped storage unit arbitrages energy prices by storing electricity in periods of low demand, and releasing stored energy when demand increases. We assume that pumped storage tanks are empty at midnight. The efficiency of pumped storage is estimated from data at 77%. Outages are represented by a time-varying pumping and production limit, and time-varying storage capacity. The unit obeys ramp rate limits at both production and pumping mode. The unit is assumed to be capable of providing primary, secondary, and tertiary reserve. The parameters of pumped storage (production/pump capacity, storage capacity, ramp rates) are estimated from the actual dispatch of the unit over the study period.

3.1.3 Neighboring Markets

The Belgian market is interconnected to France and the Netherlands. An attempt to model neighboring markets through residual supply functions that are connected to Belgium through time-varying available transfer capacities is not acceptable, since Belgium functions largely as a highway that carries power from the Netherlands to France and vice versa. Thus, the residual supply function at the French border does not correspond to the correct slope (i.e. exports from Belgium to France are increasing with respect to the price in Belgium). Alternatively, aggregate exports over both borders of Belgium can be represented as an *aggregate* export supply function. The resulting supply function, although positively sloped ($P = 39.37 + 0.0056 \cdot Q$ €/MWh), is extremely elastic. Thus, modeling imports through a residual supply function produces an inaccurate model whereby imports can be obtained at a nearly constant price up to the level of available transfer capacity. Given the inaccuracy of the resulting model, imports are instead fixed to their historical values. In order to represent the fact that the system can resort to imports under conditions of stress, the excess import capacity above the historically observed imports is modeled as an affine supply function. The intercept of this supply function is equal to the 90th percentile of the day-ahead price (70 €/MWh) and its slope is set equal to 0.2 €/MWh per MW. Thus, price-elastic imports are used only in case of supply shortage, with the marginal cost of imports rising steeply.

3.1.4 Consumers

For lack of contrary evidence, we assume an inelastic demand. We set the valuation of consumers equal to 3000 €/MWh, which coincides with the price ceiling of the day-ahead market.

3.1.5 System Operator

The Transmission System Operator (TSO) procures five types of reserve in a monthly auction. The demand of the TSO for reserve capacity is fixed, and based on publicly available data[11]. In particular, the TSO procures 55 MW of primary upward and downward reserve, 140 MW of secondary upward and downward reserve, and 350 MW of tertiary reserve.

[11] See *Potential Cross-Border Balancing Cooperation between the Belgian, Dutch and German Electricity Transmission System Operators*, October 8, 2014.

3.2 Validation

The validation of the market model described above comprises two steps. The first step of the validation process aims at explaining the observed quantities traded in the market, the second step aims at explaining the observed price at which the market clears.

3.2.1 Explaining Clearing Quantities

Figure 3 presents the dispatch of various technologies over January 2013, which corresponds to a month of relatively high demand. We focus on CCGT, coal, pumped storage production and pumping, which are the most complex technologies and whose behavior is expected to be most difficult to capture. The fit is remarkably accurate for CCGT units, whereas coal and pumped storage units present a certain degree of deviations (however, note that CCGT units represent greater capacity). By contrast, June 2013 corresponds to a month of relatively low demand. The fit of the model versus realized outcomes is presented in figure 4. We observe that the model tends to overestimate the production of CCGT units in periods of low demand. One source of inaccuracy is the fact that our model does not account for CCGT units that were decommissioned after October 2014. These units were operational during the interval covered by our study, however they are not present in the database that we use in our study. In order to make up for this mismatch, we scale the capacity of each CCGT unit by the same factor, such that the total CCGT capacity of our database matches the historically available CCGT capacity. This scaling inevitably introduces a certain degree of inaccuracy to our model. Under conditions of low load, our model will therefore tend to operate units at a technical minimum that has been inflated due to the aforementioned deviation. Since ORDC price adders come into effect during tight conditions, this inaccuracy should have minor effects on our results.

In order to further validate our market model, we compare its performance to an alternative approach whereby units are dispatched against the historically observed clearing price. The results of such a dispatch for CCGT units for January 2013 are presented in figure 5. The performance of this model is remarkably worse, compared to the market model proposed in the previous section. This indicates that the day-ahead auction conducted in the CWE likely rejects profitable bids, because *given* the historically observed prices the profit-maximizing schedule of CCGT units is quite different from what was actually observed[12].

[12]The rejection of bids that are in the money for the sake of increasing welfare can occur according to the European day-ahead market rules. Such bids are referred to as paradoxically rejected bids, as explained earlier in the paper.

Figure 3: Production of CCGT (upper left), production of coal (upper right), production of pumped storage (lower left) and consumption of pumped storage (lower right) in reality (in dashed gray) and according to the model (in solid black) for January 2013.

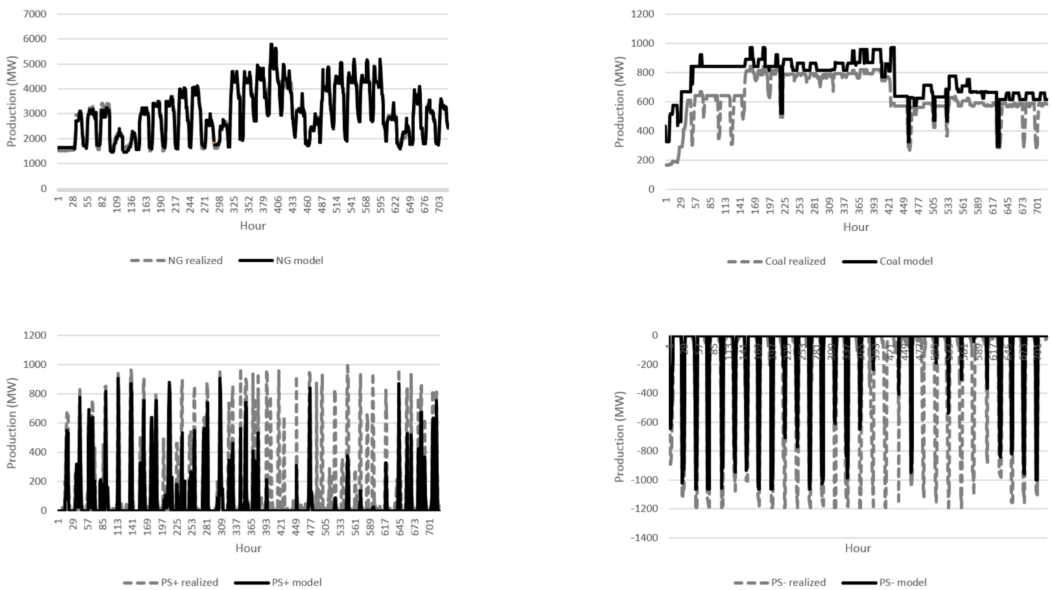


Figure 4: Production of CCGT (upper left), production of coal (upper right), production of pumped storage (lower left) and consumption of pumped storage (lower right) in reality (in dashed gray) and according to the model (in solid black) for June 2013.

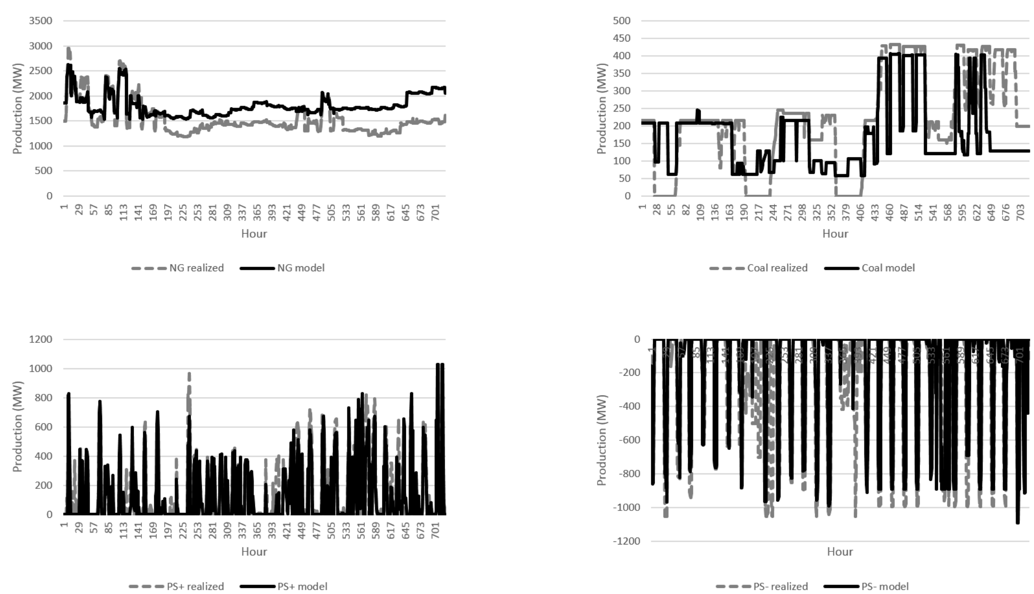


Figure 5: Production of CCGT in reality (in dashed gray) and according to the model (in solid black) for January 2013 according to a model that maximizes profits against historically observed prices.

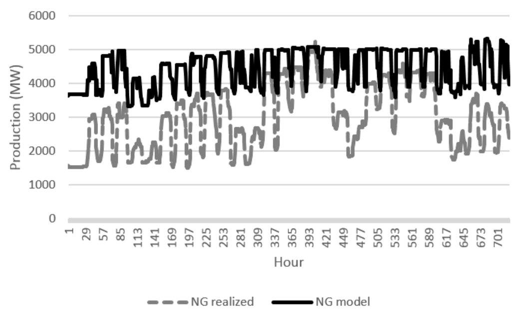


Table 1: Estimation error (in MW) for various fuels for (i) the proposed market simulation model, and (ii) a model whereby agents maximize profits against market-clearing prices.

	CCGT	Coal	PS production	PS pump
Market model ME	168.9	101.6	4.7	-20.6
Profit maximization ME	1232.2	134.4	48.5	-58.0
Market model MAE	240.7	131.6	61.6	75.4
Profit maximization MAE	1392.4	147.1	159.4	157.8
Market model RMSE	309.9	208.7	119.3	177.9
Profit maximization RMSE	1541.3	232.1	294.7	336.5

In table 1 we present the fit of the model with respect to cleared quantities by fuel. We record the root mean square error (RMSE), mean absolute error (MAE) and mean error (ME) of the proposed model and the alternative method for approximating production by maximizing profit against historically observed clearing prices. We confirm that the market model that we propose outperforms the alternative methodology for all technologies and by all metrics of performance.

One final remark can be made based on the reasonably close fit between our proposed model and the historically observed dispatch by technology. Provided our estimated market model parameters (marginal costs of dispatched units, technical and economic parameters of committed units, fuel and carbon prices, etc.) are accepted as accurate, the fact that the historically observed dispatch closely approximates the result of a centralized unit commitment schedule implies that the CWE exchange produces outcomes that can be regarded as near-optimal from the point of view of economic efficiency.

3.2.2 Explaining Clearing Prices

The observations of the previous section support the conclusion that the market clearing quantities of the Belgian power exchange can be closely approximated by a centralized unit commitment model. In this section we attempt to explain the corresponding prices that support the observed production decisions. For this purpose, we test two approaches that approximate the outcome of the Belgian exchange.

The first approach that we test fixes the unit commitment decisions determined by the centralized unit commitment model, and solves the resulting dispatch problem. The dual multipliers of the power balance constraint are used as an approximation of equilibrium prices in the exchange. Whereas this approach will capture the marginal production cost of the marginal producer, it will fail to capture the intricacies of block bids that were discussed previously.

The second approach that we test is motivated by an attempt to approximate market-clearing prices that support both continuous and block bids. The reasoning is as follows: suppose that the centralized unit commitment model provides an accurate approximation of the market-clearing production of each resource (which, based on the evidence of the previous section, is a plausible assumption). Then the resulting price produced by the CWE exchange should be such that continuous bids are cleared according to the standard rules of a uniform price auction, and accepted block bids are necessarily in or at the money. If no such prices can be found that are consistent with the production schedule determined by centralized unit commitment, then a reasonable set of prices are those that result in the minimal deviation from the rules of the exchange, i.e. the minimal loss of surplus for accepted block bids. This produces a mathematical program with equilibrium constraints, which is developed in detail in the appendix.

The relative performance of the two models is depicted graphically in figures 6 and 7. We note that the proposed price model captures a fair amount of the observed variability in prices, and explains to some extent the dispersion observed in figure 2. In particular, price dips that occur during the night are due to the fact that coal is setting the price, despite the fact that CCGT units are also producing power. This is a result of the fact that CCGT units are committed in order to provide reserve capacity. The technical minimum constraints of CCGT units, combined with the low demand of the system, result in coal units being dispatched below their technical maximum and thus setting the market price. Such an effect cannot be captured by a convex model of market behavior. Figure 6 demonstrates that, for certain months, price jumps during the day can be attributed to the unit commitment costs of CCGT units, and cannot be explained by accounting for marginal fuel costs alone. Nevertheless, it should be noted that these price jumps are not always explained by our proposed model, as shown in figure 7 which corresponds to March 2014.

The overall effect of correcting for block bids leads to a more accurate explanation of the average level of prices, as shown in table 2, where we note that the mean error of the block bid model

Figure 6: Day-ahead prices in reality (in dashed gray) and according to the model (in solid black) for January 2013. The left graph corresponds to the model that accounts for block bids, the right graph corresponds to the model that ignores block bids.

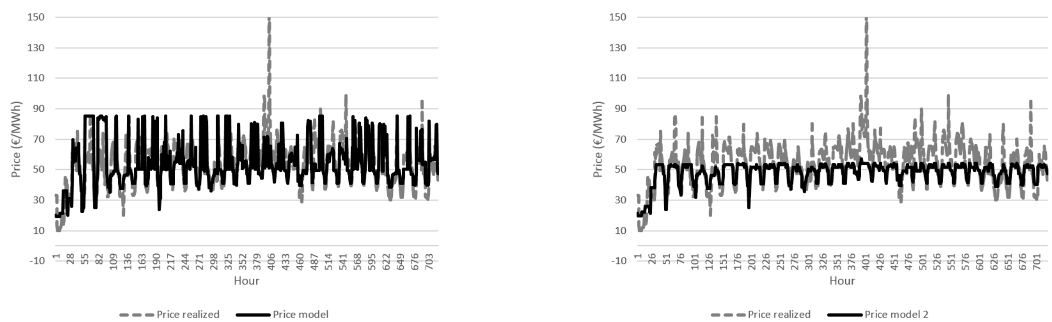


Figure 7: Day-ahead prices in reality (in dashed gray) and according to the model (in solid black) for March 2014. The left figure corresponds to the model that accounts for block bids, the right figure corresponds to the model that ignores block bids.

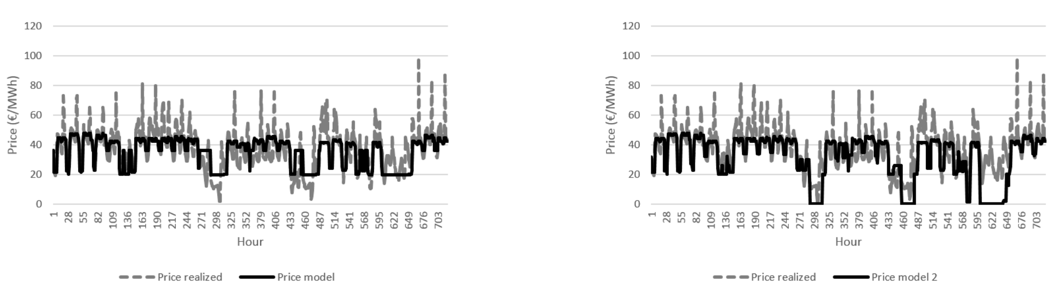


Table 2: Estimation error (in €/MWh) for (i) a model that accounts for block bids, and (ii) a model that ignores block bids.

Model with blocks ME	3.3
Model linearized ME	8.4
Model with blocks MAE	10.6
Model linearized MAE	10.6
Model with blocks RMSE	14.7
Model linearized RMSE	14.5

is lower than that of the linearized model. The equivalent performance of the two approaches in terms of mean absolute error and the slightly worse performance of the block bid model in terms of mean squared error indicate that although the effect of price jumps on average prices is captured, the block bid model may be less accurate in predicting exactly when these price jumps occur during the day. This can be understood by the fact that multiple market clearing price vectors can recover fixed costs that occur throughout the day.

4. RESULTS

In this section we follow the methodology of figure 1 for computing adders. In contrast to a model that aggregates units of the same fuel type into a single resource (Levin and Botterud, 2015), the market model presented in the previous section represents each resource individually. This is crucial for the accurate estimation of available reserve, because the ramp limits of individual units are properly accounted for when estimating system-wide available reserve. Moreover, the profitability of each unit can be estimated separately.

4.1 Estimating LOLP Parameters

We use observed activated reserve data as an indicator of capacity shortfall in a 15-minute horizon, since this is the time span over which reserves are activated in the Belgian market. If there is no involuntary load shedding, activated reserve energy corresponds to the net load deviation in real time, otherwise it is an under-estimate of net load deviation. Given that involuntary load shedding is rare in Belgium, activated reserve energy is chosen as an accurate proxy of net load deviation. A different LOLP distribution is estimated for different seasons and different intervals of the day, following the current practice of ERCOT[13]. The estimated parameters of each LOLP distribution are presented in table 3.

[13] See *Methodology for Implementing Operating Reserve Demand Curve (ORDC) to Calculate Real-Time Reserve Price Adder*, version 0.7, ERCOT, 2013.

Table 3: Mean and standard deviation of 15-minute shortfall.

Seasons	Hours	Mean	St dev	Season	Hours	Mean	St dev
Winter	1, 2, 23, 24	-31.18	96.42	Summer	1, 2, 23, 24	7.52	89.68
	3-6	-34.88	83.51		3-6	-3.63	79.13
	7-10	8.20	103.47		7-10	3.03	92.52
	11-14	-26.39	185.15		11-14	6.51	135.41
	15-18	-19.74	136.75		15-18	0.50	127.57
	19-22	7.58	102.46		19-22	11.40	98.22
Spring	1, 2, 23, 24	9.14	97.69	Fall	1, 2, 23, 24	-27.84	86.06
	3-6	-0.45	77.12		3-6	-24.24	73.11
	7-10	14.39	103.85		7-10	19.45	97.07
	11-14	-17.89	168.62		11-14	-23.08	129.76
	15-18	-58.75	175.45		15-18	-8.92	116.73
	19-22	12.80	105.87		19-22	6.57	94.19

4.2 Estimating Reserves

The amount of available reserves in a given time period depends on which resources are committed for the period in question, and the response time of the required reserve. A greater response time increases the amount of reserve that can be made available, while at the same time increasing the amount of uncertainty that the system might face, as demonstrated in figure 8. Given response time Δ, the amount of available reserve in each period is computed as follows:

$$R_\Delta = \sum_{g \in BB} \min(P_{gt} - p_{gt}, \Delta \cdot RR_g) \cdot u_{gt} + \sum_{g \in CB} \min(P_{gt} - p_{gt}, \Delta \cdot RR_g) + DR - IB, \qquad (12)$$

where BB corresponds to committed resources, CB corresponds to dispatched resources, P_{gt} and RR_g corresponds to the production capacity and ramp rate of each resource respectively, p_{gt} corresponds to the dispatch of resources, u_{gt} corresponds to the unit commitment of committed resources, DR corresponds to the amount of demand response that is available as reserve capacity[14], and IB corresponds to the real-time imbalance recorded by the system operator for the period in question. The dispatch of dispatchable and committed resources, p_{gt}, and the commitment of committed resources, u_{gt}, are provided from the unit commitment model that is described in the previous section. More specifically, the unit commitment model is run against real-time demand adjusted for imbalance (which is used as an estimate of the demand forecast fifteen minutes ahead of real time). Running the unit commitment model against real-time demand represents the corrections that would take place in the intra-day time frame.

[14]The Belgian market relies on 27 MW of primary demand response reserve and 261 MW of tertiary demand response reserve.

Figure 8: The loss of load probability as a function of reserve response time: for greater response time, $t_2 > t_1$, the system faces more uncertainty (note the greater variance of the distribution in the right), but more reserve can be made available ($Rt_2 > Rt_1$).

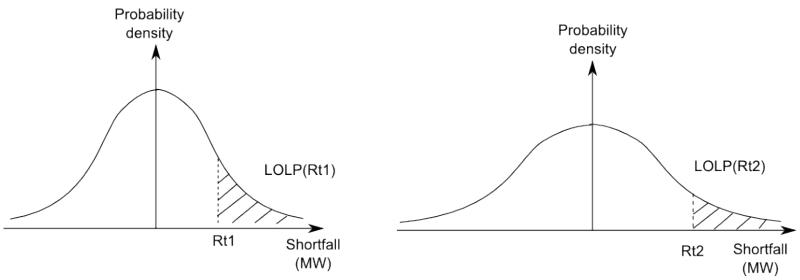


Figure 9: The amount of available reserve for January 2013 for four different response times: (i) seven minutes, (ii) fifteen minutes, (iii) thirty minutes, and (iv) one hour.

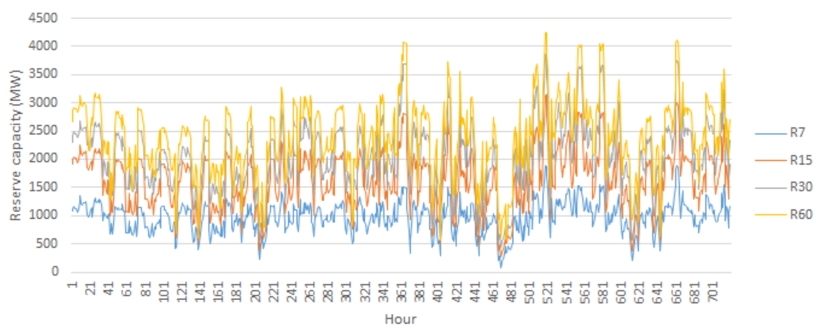


Figure 9 presents the amount of available reserves for different horizons for the first month of the case study. The great difference between the amount of reserve that can be made available in seven and sixty minutes underscores the need for modeling individual units separately when attempting to estimate the available reserve capacity for different time horizons. For example, in hour 469 the amount of 7-minute reserve amounts to 81.1 MW, whereas the amount of 60-minute reserve amounts to 609.5 MW. For the same period, the loss of load probability amounts to 99.4% for a 7-minute horizon, and 80.5% for a one-hour horizon.

4.3 Generator Profitability

In order to estimate the profits of individual units, we use the historical energy and reserve prices and the output of the unit commitment model in order to estimate revenues and operating costs. We focus specifically on CCGT units, whose economic viability is questioned despite the fact that these resources are best suited (in terms of technical capabilities) for providing flexible reserve capacity to the system. The profits of CCGT units are computed for historical prices as they occurred over the duration of the study, as well as for profits that would have occurred if the ORDC price adder were

Table 4: Profitability of CCGT units before and after adding ORDC price adders, and average adder benefit.

	Profit (€/MWh), no adder	Profit (€/MWh), with adder	Adder benefit (€/MWh)
CCGT1	**3.0**	9.2	7.3
CCGT2	**0.7**	**2.9**	11.4
CCGT3	**0.5**	8.4	6.6
CCGT4	**3.1**	9.8	8.9
CCGT5	**0.3**	**4.6**	5.6
CCGT6	**3.2**	7.1	5.8
CCGT7	**0.4**	**2.4**	5.8
CCGT8	**0.5**	6.6	6.3
CCGT9	**1.7**	9.5	8.3
CCGT10	**1.0**	6.1	14.3
CCGT11	**1.0**	**3.4**	7.2

applied to the energy price. We use equation (11) in order to adjust the price adder for the provision of reserve whose respective delivery times amount to 7 and 15 minutes.

Eleven CCGT units operate currently in the Belgian electricity market. The output of the market model permits a computation of CCGT profits. Table 4 presents the profitability of each unit before and after the introduction of price adders[15]. These profits should be compared against the running investment cost of a typical CCGT unit in order to ascertain the economic viability of CCGT resources. The running investment cost of CCGT is estimated[16] at 5.6 €/MWh. Profits that do not exceed 5.6 €/MWh in the table are highlighted in bold font in order to indicate that the given unit is not economically viable. The profit in the first column is computed as the profit over the entire duration of the study given historically realized prices, normalized by the capacity of each unit and the number of hours in the study period. The profit in the second column is computed in the same way, where prices have been adjusted according to the price adder. The final column represents the extra profit earned by each CCGT unit due to the introduction of the adder, normalized by the total output of each unit.

Two notable conclusions can be drawn from the first two columns of table 4: (i) CCGT profits, as estimated by the methodology set forth in the present paper, are not sufficient for ensuring the economic viability of *any* CCGT unit. This observation is aligned with the existing policy debate, which has focused on the fact that the existing market design is not sufficient for ensuring the economic viability of flexible resources, although these resources are necessary for supporting the integration of renewable energy resources. (ii) Adders, as computed in the study, could potentially render the

[15]The reported profit accounts for a fixed operating and maintenance cost of 7.04 \$/kW-year (EIA 2012 estimate) at the average 2012 exchange rate of 0.778 €/\$.

[16]The estimate is based on an overnight cost of 676 \$/kW (EIA 2012 estimate), the 2012 average exchange rate of 0.778 €/\$, continuous discounting at rate of return of 8%, and an investment horizon of 25 years.

majority (seven out of eleven) of CCGT units economically viable. This confirms the fact that these resources add value to the system, although paradoxically the existing market design is pushing these resources out of the market.

In the last column of table 4 we present the average adder benefit accrued by each CCGT unit. This adder benefit is computed as the difference of the revenue earned by each unit before and after the introduction of the adder, divided by the total production of each unit over the entire study period. The average adder for the duration of the study amounts to 5.3 €/MWh. This is the average increase in revenues that can be expected, for example, by base-load units that produce a constant output. By contrast, the adder benefit presented in the last column of the table is effectively higher for *all* CCGT units, and amounts to up to 14.3 €/MWh for CCGT10. Whereas a capacity market would treat CCGT and base-load units identically, the ORDC mechanism rewards flexible units more handsomely by design. This effect is a result of the positive correlation of the output of CCGT units with price adders. Stated equivalently, flexible units are able to increase their output under conditions of system scarcity, and are rewarded accordingly by the ORDC mechanism.

An assessment of the impact of the ORDC adder on the long-run redistribution of welfare would require modeling the feedback of the adder on investment. Such an analysis should also attempt to quantify consumer benefits from the impact of the ORDC on the loss of load probability. This is a separate calculation in its own right, which goes beyond the scope of the present paper. Assuming identical dispatch with and without the ORDC adder, the welfare implications of the introduction of the adder amount to a transfer from resources that under-supply in the real-time market relative to their forward positions to resources that respond to conditions of scarcity by increasing their output. The additional real-time energy market revenues accruing from the adder therefore increase the profit of CCGT units that offer real-time response, and are paid for by resources that deviate from their forward positions. Such resources can include generators (e.g. wind generators that over-estimate their production in the day-ahead market) as well as loads that consume above their forward contracted quantity.

5. CONCLUSIONS AND PERSPECTIVES

Discussions on whether energy-only markets or capacity remuneration mechanisms should be used to restore incentives to invest in the European power sector have been going on since several years without clear-cut conclusions. DG COMP and its Sector Inquiry provided a new element to the debate: according to DG COMP, capacity remuneration mechanisms, as implemented in the EU, are conducive of "State Aids" and hence cannot be used as a generic incentive for investment; they can be accepted in particular situations and only when properly justified. At the same time the power industry repeats that it sees those mechanisms as indispensable for remedying the lack of incentives to invest in the power sector. This dichotomy of positions justifies exploring whether a mechanism such as ORDC, which has been absent from the discussions so far, could help bridge or reduce the gap between these positions.

ORDC is supported by a well-developed theory and is implemented in several US markets. Testing it for the EU market or part of it requires a credible model of this market and some sufficiently large period of observation to simulate its operation. We adopt the version of ORDC implemented in ERCOT that we find closer to the EU market and try to develop some plausible representation of the price formation in the European Market Coupling, even if limited to Belgium. We find that ORDC fulfills its objective: flexible resources in the Belgian market that were not viable given historical energy and ancillary services prices in the retained 21-month period would have been so if price adders correctly reflecting scarcity had been introduced. This justifies introducing the method in the debate and checking whether it would meet the requirements of competition authorities, while at the same time providing at least some of the incentive to invest that is required by the industry.

ORDC is an energy-only market design based on an arbitrage between the capacity operating in the energy market and the one reserved for dealing with real-time uncertainty. This arbitrage is conducted in real time, taking full account of the state of the system; it computes the value of the reserve capacity as the economic value of the energy that a plant could produce in case of capacity shortfall. The payment accruing to a plant is based on its capability to respond in real time, irrespectively of the technology: it is thus non-discriminatory. The arbitrage between capacity on the energy and reserve markets would be perfect in a market design that co-optimizes energy and reserve. The value of the capacity is then computed in real time. The arbitrage is imperfect when the capacity allocated to reserve does not derive from co-optimization as in ERCOT and hence also in our analysis[17]. ORDC thus explicitly performs in real time or ex post the capacity valuation that economic agents implicitly conduct ex ante over the horizon spanning the capacity and energy markets in usual capacity markets. Referring to DG COMP concerns, ORDC is inherently free of State Aid, provided the mechanism for computing the opportunity cost of reserve capacity in the energy market is properly audited and all capacities are valued on the same instantaneous energy market. ORDC also

[17] Recall the distinction made earlier between the mark-up on energy in a co-optimized system and an adder when there is no co-optimization (as in the case of both ERCOT and the EU).

dispenses with the bureaucratic justification of capacity mechanisms required by the Commission: the method indeed only provides additional revenue when the generation system is tight and becomes idle when capacity is sufficient. ORDC automatically and instantaneously adapts to the system tightness. ORDC also dispenses with the need to verify plant availability beyond what is required today by the provision of reserve. Moreover, the valuation of capacity provided by ORDC can be made more comprehensive by valuing the opportunity cost of capacity used for ancillary services.

The real-time arbitrage conducted by ORDC is in line with the importance given by DG COMP to efficient short-term markets in the Sector Inquiry. This focus on short-term markets departs from the traditional European view, which so far only emphasized the day-ahead market. In contrast, the report of the Sector Inquiry emphasizes the importance of an efficient short-term market for sending the right signal on scarcity of capacity (which, in the argument of DG COMP, makes the capacity market redundant). This emphasis on short-term market design can only be logically justified if one admits that scarcity of capacity is only properly revealed in real time (where binding constraints are effectively revealed), an argument that has long been made in most non-European restructured power markets, but has so far remained absent in the European scene. ORDC reveals that value, using an instantaneous time granularity where the distinction between the capacity and energy markets evaporates and the value of scarce flexible capacity is expressed in the instantaneous price of energy. This principle can be at the origin of a full overhaul of the current system. It remains to be seen how far European competition authorities will be willing to use their power to achieve this needed overhaul.

But ORDC can only be a help. It makes the short-term market efficient but does not solve the long-term problem of incentives for investment when the long-term risk has become unmanageable. ORDC constructs an efficient short-term signal that deals with the risk and variability associated to contingencies and forecast errors. At least two difficulties remain. This short-term signal should propagate to the long term, which requires a system of well-functioning forward markets, at least from real time to the day ahead. This problem is only partially solved today (Parsons et al., 2015); it will in any case require a closer relation between the day-ahead and real-time market, something that is not on the European agenda today. Even then the signal given by the short-run market remains volatile with respect to long-term demand and regulatory risks: other economic instruments are necessary for effectively transforming the short-term signals into efficient long-term economic incentives. These can be long-term contracts (bilateral or traded) or residual capacity markets (Hogan, 2013). The problem of creating a market that conveys short-term signals to the long term is not discussed in the

Sector Inquiry; it also goes beyond the scope of this paper. It should not be taken for granted that the market will just solve it.

6. APPENDIX

6.1 Agent Models

The notation used in the sequel is summarized as follows:

Decision variables

- p_t: production in period t
- $r1U, r1D, r2U, r2D, r3$: primary up/down, secondary up/down, tertiary reserve for a month
- u_t, su_t, sd_t: unit commitment, startup and shutdown decisions for committed unit in period t
- d_t: power consumption of pumped storage / loads
- e_t: stored energy in reservoir

Parameters

- $MC(x)$: marginal cost curve of a dispatchable or committed generator, for dispatchable generators we have $MC(x) = a + bx$
- R: ramp rate of a dispatchable/committed generator
- $PMax_t$: technical maximum of a dispatchable/committed generator or pumped storage unit
- $PMin_t$: technical minimum of a committed generator
- SUC, MLC: startup / min load cost of a committed generator
- UT, DT: minimum up and down times
- η: pumping efficiency of pumped storage units
- $DMax_t$: pumping limit of pumped storage unit
- ES_t: energy storage capacity of pumped storage unit
- RP_t, RC_t: production and pumping ramp rate of pumped storage units

Prices

- λ_t: energy price in period t
- $\lambda R1U$, $\lambda R1D$, $\lambda R2U$, $\lambda R2D$, $\lambda R3$: price for primary up/down, secondary up/down, tertiary reserve capacity for a given month

6.1.1 Dispatchable Generators

Dispatchable resources are described by the following model.

$$\max \sum_t (\lambda_t \cdot p_t - \int_{x=0}^{p_t} (a + bx)dx) +$$
$$\lambda R1U \cdot r1U + \lambda R1D \cdot r1D + \lambda R2U \cdot r2U + \lambda R2D \cdot r2D + \lambda R3 \cdot r3 \quad (13)$$
$$\text{s.t.} \quad p_t \geq r1D + r2D \quad (14)$$
$$p_t + r1U + r2U + r3 \leq PMax_t \quad (15)$$
$$r1U \leq 0.5 \cdot R, r1D \leq 0.5 \cdot R \quad (16)$$
$$r2U \leq 7 \cdot R, r2D \leq 7 \cdot R \quad (17)$$
$$r3 \leq 15 \cdot R \quad (18)$$
$$p_t, r1U, r1D, r2U, r2D, r3 \geq 0 \quad (19)$$

The horizon of the model is one month. Reserve capacity decisions are static, meaning that the decision is fixed for the entire month on the basis of a capacity reserve auction. The objective function maximizes profits that accrue from selling power in the energy market and reserve in the reserve capacity auctions. Constraint (14) requires that if a unit is to offer downward reserve it must already be producing power in order to be able to ramp down if needed. Constraint (15) limits the amount of power and reserve offered by a unit by the capacity of the unit. Constraints (16) - (18) determine the amount of reserve that can be offered by a unit as a function of the response time of the reserve and the ramp rate of a unit.

6.1.2 Committed Generators

Committed generators are described by the following model.

$$\max \sum_t (\lambda_t \cdot p_t - \int_{x=0}^{p_t} MC(x)dx - SUC \cdot su_t - MLC \cdot u_t) +$$
$$\lambda R1U \cdot r1U + \lambda R1D \cdot r1D + \lambda R2U \cdot r2U + \lambda R2D \cdot r2D + \lambda R3 \cdot r3 \quad (20)$$
$$\text{s.t.} \quad p_t - r1D - r2D \geq PMin_t \cdot u_t \quad (21)$$
$$p_t + r1U + r2U + r3 \leq PMax_t \cdot u_t \quad (22)$$
$$u_t = u_{t-1} + su_t - sd_t \quad (23)$$
$$\sum_{\tau=t-UT+1}^{t} su_t \leq u_t, \sum_{\tau=t-DT+1}^{t} sd_t \leq 1 - u_t \quad (24)$$
$$(16) - (18)$$
$$p_t, r1U, r1D, r2U, r2D, r3 \geq 0 \quad (25)$$
$$u_t, su_t, sd_t \in \{0, 1\} \quad (26)$$

The objective function of committed resources includes, in addition to the terms of dispatchable resources, the startup and minimum load costs associated to unit commitment. Constraint (21) limits the amount of power and upward reserve that can be offered by a unit to the technical maximum of a unit, provided the unit is online. Constraint (22) applies an analogous limit on power supply and downward reserve, based on the technical minimum of a unit. Constraint (23) describes the dynamic evolution of the unit commitment status of a generator, as a function of startup and shutdown decisions. Constraints (24) describe the minimum up and down times of the generators. All data required for formulating the above model has been recovered from public or non-public commercial databases, as described in section 3.

6.1.3 Pumped Storage Model

The pumped storage unit can be described by the following model:

$$\max \sum_t (\lambda_t \cdot (p_t - d_t) +$$
$$\lambda R1U \cdot r1U + \lambda R1D \cdot r1D + \lambda R2U \cdot r2U + \lambda R2D \cdot r2D + \lambda R3 \cdot r3 \quad (27)$$
$$\text{s.t.} \quad p_t + r1U + r2U + r3 \leq PMax_t \quad (28)$$

$$d_t + r1D + r2D \leq DMax_t \tag{29}$$

$$e_t = 0, t \in \{1, 25, 49, \ldots\} \tag{30}$$

$$e_t = e_{t-1} + \eta \cdot d_{t-1} - p_{t-1} \tag{31}$$

$$p_t - p_{t-1} + r1U + r2U + r3 \leq RP_t \tag{32}$$

$$p_t - p_{t-1} - r1D - r2D \geq -RP_t \tag{33}$$

$$d_t - d_{t-1} + r1D + r2D \leq RD_t \tag{34}$$

$$d_t - d_{t-1} - r1U - r2U - r3 \geq -RD_t \tag{35}$$

$$e_t \leq ES_t \tag{36}$$

$$(16) - (18)$$

$$p_t, d_t, e_t, r1U, r1D, r2U, r2D, r3 \geq 0 \tag{37}$$

Note that pumped storage units incur no intrinsic operating cost, instead they accrue revenue for producing at peak hours and buy back power from the market in low-demand periods. Constraints (28) and (29) impose technical limits based on the maximum production and pump rate of the unit. According to constraint (30), the reservoir of the unit is assumed to be empty at midnight of every day. The energy stored in the reservoir of the unit evolves according to the dynamics of equation (31). Ramp rates in production for the upward and downward direction are imposed respectively by constraints (32) and (33) respectively. Similarly, ramp rates in pumping mode are imposed through constraints (34) and (35). Constraint (36) imposes a limit on the amount of energy that can be stored in the reservoir of the unit. The production and pump limits, efficiency, and ramp rates of the pumped storage unit are estimated from the dispatch of the unit over the study period. Note that nothing precludes the possibility that the unit produces and pumps power simultaneously, a phenomenon that is actually observed in the data.

6.2 Solution Methodology

The resolution of the market model of section 3 requires solving a unit commitment problem over an entire month. A direct resolution of the problem through branch and bound results in excessive run time. On the other hand, a dual decomposition algorithm that relaxes the generator coupling constraints results in numerical instability and slow convergence. In this section, we present a heuristic method that converges within a reasonable amount of computing time within an acceptable optimality gap. The approach is motivated by the need to decompose the problem in order to accelerate its resolution. In particular, a receding horizon heuristic algorithm is used, which can be described as follows:

1. Initialize the commitment of all units for all hours to ‘on’
2. For $iter = 1 \ldots IterLimit$
   - For $day = 1 \ldots 30$
     - Solve the entire model for the entire horizon, with unit commitment decisions fixed for all days except today and tomorrow
     - Fix commitment for today only, step one day forward

The receding horizon heuristic is observed to outperform the aforementioned alternatives (branch and bound and dual decomposition) in terms of best solution found within three hours of running time, which was the run time limit set for each month.

6.3 Approximating CWE Clearing Prices

In this section we describe a model for approximating the prices of the Belgian power exchange, *given* market clearing quantities by resource. The set of producers is partitioned between continuous bids CB and block bids BB. Continuous bids include dispatchable resources, as well as coal units that are anyways expected to run and are therefore more easily represented through continuous bids. Block bids apply to CCGT units. This model receives as input a predetermined vector of *daily* production and unit commitment for each resource, represented as $p^\star_g = (p^\star_{g1}, \ldots, p^\star_{g,24})$ for $g \in CB \cup BB$ and $u^\star_g = (u^\star_{g1}, \ldots, u^\star_{g,24})$ for $g \in BB$.

$$\min \sum_g ss_g \tag{38}$$

$$\text{s.t.} \quad p_{gt} = p^\star_{gt}, g \in CB \cup BB \tag{39}$$

$$0 \leq p_{gt} \perp MC_g(p_{gt}) - \lambda_t + sr_{gt} \geq 0, g \in CB \tag{40}$$

$$0 \leq sr_{gt} \perp PMax_{gt} - p_{gt} - r1U^\star_g - r2U^\star_g - r3^\star_g \geq 0, g \in CB \tag{41}$$

$$ds_g = \sum_t \lambda_t \cdot p^\star_{gt} - TC_g(u^\star_g, p^\star_g) + ss_g, g \in BB \tag{42}$$

$$ds_g \geq 0, g \in BB \tag{43}$$

Constraint (39) fixes the production of all resources to their optimal values. Given a market clearing price λ_t for each period (to be determined), the dispatch of continuous bids that follows the rules of a uniform market clearing auction can be described by the optimality conditions of equations (40)-(41), where sr_{gt} corresponds to the scarcity rent of a continuous bid. Note that reserve commitment decisions have also been fixed to their optimal values.

For block bids, their fixed schedule is associated with a total cost $TC_g(u_g^\star, p_g^\star)$. The daily surplus of a block bid is described by ds_g and must be non-negative. If a price vector $(\lambda_1, \ldots, \lambda_{24})$ that produces a non-negative daily surplus cannot be found, then the surplus shortage ss_g of block g becomes non-zero. The objective of the model is to find prices λ_t such that the supply shortage over all block bids is minimized. This model attempts to find prices that respect the day-ahead clearing decisions while respecting, as closely as possible, the rules of the exchange.

ACKNOWLEDGEMENTS

The authors benefited from discussions with William Hogan, Shmuel Oren, Alain Marien, Jacques Gheury, and Resmi Surendran. The authors acknowledge the financial support of the Belgian Regulatory Commission for Electricity and Gas (CREG). The first author has been supported by the Engie Chair on Energy Economics and Energy Risk Management.

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