An Extended Analysis on the Remuneration of Capacity under Scarcity Conditions

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ABSTRACT

This paper extends a recent analysis which investigated the impact of operating reserve scarcity adders on the financial viability of generation units in the Belgian market. The extension of this analysis reports on the sensitivity of scarcity pricing with respect to the value of lost load, the availability of strategic reserve, and the correlation of imbalances over consecutive operating intervals. We report the following findings: (i) the restoration of nuclear capacity in the Belgian market would suppress scarcity adders to near-zero values; (ii) the increase in value of lost load would have a minor impact on scarcity adders when capacity shortages are negligible; (iii) strategic reserve mutes scarcity adders, and its removal from the Belgian market would have a significant impact on scarcity adders; (iv) consecutive imbalance increments exhibit strong positive correlation, and ignoring this correlation can result in overestimation of scarcity adders. We comment on the implications of these findings on the effectiveness of the European market design for providing incentives to investment.

Keywords: Flexibility, energy-only markets, renewable integration, operating reserves

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1. INTRODUCTION

The "Operating Reserve Demand Curve" (ORDC) was introduced in the Electric Reliability Council of Texas (ERCOT) in 2014 as an "energy-only" instrument for dealing with adequacy. The method is well documented in theory and practice (e.g. (Potomac, 2017, 2016; Hogan and Pope, 2017) and references therein). The general conclusion of these existing market analyses is that ORDC behaves as expected; various recommendations to improve both the method and its supporting market design can be made, but none of the findings question the fundamentals of the approach. Papavasiliou and Smeers (2017) analyze the possible transposition of ORDC to the European context, focusing on the particular case of Belgium. The study was demanded by the Belgian Commission for the Regulation of Electricity and Gas (CREG); it was motivated by adequacy concerns that developed in the country and some of its neighbors. The study simulates the potential impact of ORDC-based scarcity adders in the Belgian electricity market over a period of 18 months, from January 2013 until September 2014. It was partially motivated by concerns triggered by an unscheduled outage of approximately 4 GW of nuclear capacity in Belgium during the fall of 2014. As the total capacity of the Belgian system amounts to 14765 MW, this outage represented a significant portion of the domestic power generation fleet.

In February 2016, nuclear power production was completely restored back to service. In response, the CREG commissioned an extension of the original study conducted by Papavasiliou and Smeers (2017), in order to investigate the effect of the restoration of nuclear capacity on the Belgian market during the 9-month period from September 2015 until March 2016, as well as the sensitivity of scarcity adders on a number of factors. In this paper, we briefly recall some main findings of the first study and additionally focus on the following new objectives:

- an assessment of the impact of ORDC scarcity adders on the electricity market under a baseline scenario of September 2015 until March 2016 (referred to as the *reference* horizon);
- an assessment of the impact of ORDC on the reference horizon with the value of lost load (VOLL) of 3000 €/MWh replaced by a VOLL of 8300 €/MWh;
- an assessment of the impact of the removal of strategic reserve on the ORDC adder for the reference horizon[1];

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[1] Belgium operates on an energy-only basis complemented since 2014 by a so-called "strategic reserve". This reserve comprises plants that do not participate in the energy market, but can be activated in case of scarcity as determined by the system operator; Höschle and Vols (2016) provide a description of the mechanism.

- a short elaboration on the issue of "back-propagation" of the adder, which was already mentioned in the first study. By definition, the adder does not back-propagate when it only applies to the real-time transactions (a small part of the market); it back-propagates when it applies to the whole day-ahead and real-time transactions[2]. The question relates to differences between the US (e.g. of the ERCOT type) and EU market designs.
- a statistical analysis that would verify or refute the independence of imbalances for the reference horizon in the computation of the LOLP;
- possible recommendations on the modification of the ORDC adder computation in case where imbalance increments in the computation of the LOLP are not independent over consecutive time periods.

The paper is organized along these different points. We believe that the combination of the results of this and the former study contributes to the energy policy literature by offering a range of contrasted situations that illustrate well the functioning of ORDC. Their analysis in the comparative context of the EU and ERCOT market designs also raises questions that relate directly to some positions of European competition authorities in favor of energy-only approaches to investment and its efficiency.

2. METHODOLOGY

2.1 A Short Review of Scarcity Adders

In our previous report (Papavasiliou and Smeers, 2017) we provide a detailed discussion about the debate on energy-only markets versus capacity remuneration mechanisms in the context of the evolution of the European electricity market. The relative merits and criticisms of energy-only markets and capacity remuneration mechanisms are discussed in detail. It is specifically noted that capacity remuneration mechanisms have recently raised concerns among European policy makers as potentially balkanizing the European electricity markets, and as possibly hiding State Aids that contravene European law. On the other hand, energy-only markets rely on price spikes for remunerating capacity, however in the presence of inelastic demand these price spikes are somewhat unpredictable in magnitude and frequency, and can be easily muted by regulatory interventions such as price caps or the mobilization of emergency capacity, thereby resulting in increasing risk for power generation

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[2] It is straightforward to show that the two-settlement system whereby real-time prices apply to deviations of forward traded quantities relative to physically delivered quantities is equivalent to real-time prices applied to the *entire* quantity traded in real time followed by settlement of forward contracts (Stoft, 2002).

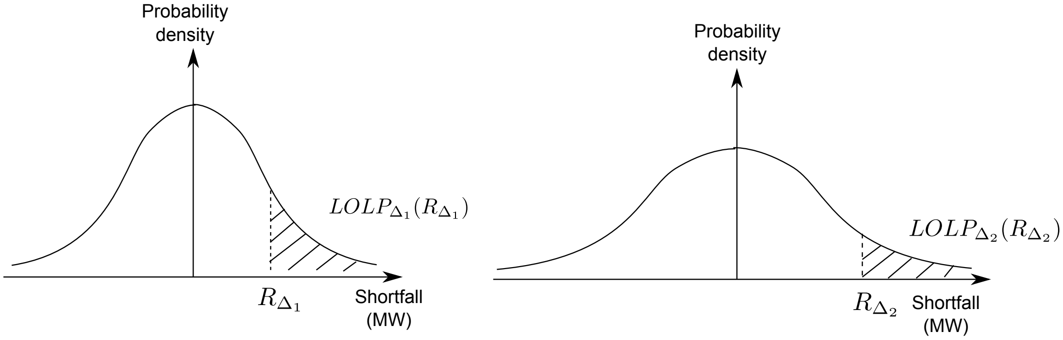
capacity investments. The interesting paradox is that the technologies which are undergoing the gravest economic woes due to the integration of renewable resources and the resulting depression of energy prices are those technologies which are most suitable for balancing the highly variable and unpredictable fluctuation of renewable energy supply, namely combined cycle gas turbines. This indicates a fundamental inconsistency in the valuation of flexible reserve capacity, where 'flexible' refers to capacity that is capable of varying its output rapidly, and in short notice.

Operating reserve demand curves have been introduced as a potential remedy to how reserve capacity is valued (Hogan, 2005), and thus as a potential remedy to the missing money problem that arises in energy-only markets. The idea of ORDC scarcity adders is to introduce a component to the real-time energy price which reflects the value to the system of keeping a certain amount of fast-responsive generation capacity on standby, thereby reducing the instantaneous loss of load probability in the system. This adder to the real-time price essentially reflects the willingness of the system operator to pay for increments of reserve capacity in tight conditions, and it is therefore adaptive to the amount of generation capacity that is available in the system: excessive availability of reserve capacity pushes this adder to zero, thereby leaving the energy price unaffected, as one would expect under normal operating conditions. Instead, under tight conditions when the amount of available reserve capacity in the system becomes scarce, the adder increases, thereby reflecting the added value to the system of increments in standby reserve. Units that can respond under such tight conditions are remunerated for helping the system, and provided that forward markets can properly back-propagate the real-time value of electricity, a long-term investment signal emerges.

Whereas the ORDC adder is developed as a correction to the energy price for a US-type two-settlement system that simultaneously auctions reserve capacity and energy, the implications in the level of investment of introducing the adder to the European market would need to be analyzed more carefully. This issue is only briefly addressed in the current study by a few comments on back-propagation. Instead, the current study is focused on an open-loop analysis of how the adder would have impacted the Belgian real-time electricity price, and the resulting profitability of existing combined cycle gas turbines.

The ORDC adder can be derived through an analysis of the KKT conditions of a two-stage stochastic dispatch model (Hogan, 2013; Papavasiliou and Smeers, 2017), and the resulting real-time

Figure 1: 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 on the right), but more reserve can be made available ($R_{\Delta_2} > R_{\Delta_1}$).



energy price is computed as follows:

$$\begin{aligned}&\lambda = MC_{g_m}(p_{g_m}) + \\ &\frac{T_1}{T_1+T_2}(VOLL - \hat{MC}(\sum_g p_g)) \cdot LOLP_{\Delta_1}(R_{\Delta_1}) + \\ &\frac{T_2}{T_1+T_2}(VOLL - \hat{MC}(\sum_g p_g)) \cdot LOLP_{\Delta_2}(R_{\Delta_2}).\end{aligned} \quad (1)$$

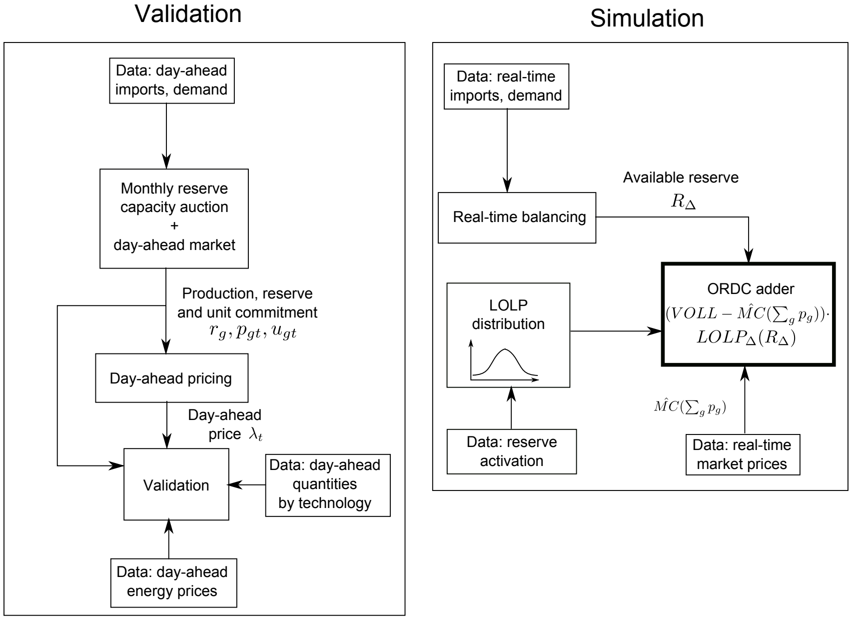
In the above formula, $MC_{g_m}(p_{g_m})$ is the marginal cost of the marginal unit, as in an energy-only market without an adder. $VOLL$ represents the value of lost load. The function $\hat{MC}$ is introduced by Hogan (2013) as the incremental cost of operations of the system for meeting an increment in demand, for example one could employ the merit order function of the system when transmission constraints are ignored. The function $LOLP_{\Delta_i}(R_{\Delta_i})$ maps the amount of reserve that is available to the system and which can respond within Δ_i minutes (e.g. 7.5 minutes for secondary reserve, and 15 minutes for tertiary reserve) to the loss of load probability, given the uncertainty that the system is facing in a horizon of Δ_i minutes. This concept is illustrated graphically in figure 1. Finally, $T_1 = \Delta_1 < \Delta_2 = T_1 + T_2$.

2.2 A Short Review of the Methodology of the Original Study

The focus of our original study was to develop an accurate model of the Belgian market, which could accurately predict the available reserve R_{Δ_i} in the computation of the ORDC adder in formula (1). This would provide an accurate estimate of what the ORDC adder would have been, if the design had been introduced in the Belgian market.

The methodology employed in the original study is detailed in figure 2. The study consisted

Figure 2: A schematic diagram of the proposed methodology of the original study (Papavasiliou and Smeers, 2017). The left block indicates the validation of the market model.



of a validation phase and a simulation phase. In the validation phase, we used historical data of market clearing prices and market clearing volumes in the Belgian market in order to calibrate our market model, and in order to decide on the level of modeling detail for the various resources that were accounted for in the model. These modeling decisions were made under the constraint of data availability, since the data that was available to us was in aggregate form (with generators of the same fuel type being aggregated as a single resource), whereas data for combined cycle gas turbines and coal units was available on a unit-by-unit basis.

Upon validating our market model against a number of benchmarks, we proceeded with the computation of the ORDC adder for the study interval from January 2013 until September 2014. The average adder for the study amounted to 5.3 €/MWh. Results are summarized in table 1. The conclusions of the original study can be summarized as follows: (i) based on the observed market outcomes of the original study period, none of the existing combined cycle gas turbines of the Belgian market appear to be profitable investments, 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.

TABLE 1
Profitability of CCGT units before and after introducing ORDC price adders, and average adder benefit. Original study interval: January 2013 - September 2014. Bold font indicates units that are not able to recover their fixed investment costs.

	Profit no adder (€/MWh)	Profit with adder (€/MWh)	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	8.3
CCGT7	**0.4**	**2.4**	14.4
CCGT8	**0.5**	6.6	7.2
CCGT9	**1.7**	9.5	6.9
CCGT10	**1.0**	6.1	5.9
CCGT11	**1.0**	**3.4**	6.4

3. ASSUMPTIONS OF THE NEW STUDY

The present report extends the results of the original study in the following directions: (i) the Belgian market is tested with nuclear power units back in operation, with the reference horizon for the new study ranging from September 2015 until March 2016; (ii) the reference horizon is tested for the case where the VOLL used for the computation of the adder in equation (1) is changed from 3000 €/MWh to 8300 €/MWh; (iii) the reference horizon is tested for the case where strategic reserve would not be available to the Belgian transmission system operator.

We assume the same requirements for primary reserve (FCR), secondary reserve (aFRR) and tertiary reserve (mFRR) as in the original study: 55 MW for primary upward and downward reserve, 140 MW for secondary upward and downward reserve, and 350 MW for tertiary reserve[3].

The time resolution of the new model is 15 minutes, compared to the original model which was cast in 1-hour time steps. This enables a more accurate simulation of the actual Belgian system, which operates a balancing market with 15-minute time intervals. Specifically, for the day-ahead unit commitment model that we employ, we use 15-minute resolution for dispatch decisions, and hourly resolution for unit commitment decisions. Reserve capacity commitment is modeled with daily resolution, reflecting a transition of the Belgian market to day-ahead clearing of reserve capacity.

The CREG has provided detailed information on the amount of strategic reserve that was available

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[3] The 350 MW of tertiary reserve capacity correspond to the reserve capacity that needs to be made available by thermal units (EBridge, 2014). There are also 261 MW of tertiary reserve capacity sourced from demand response. This capacity is accounted for in the computation of the ORDC adders. This capacity is not included in the reserve requirements of the unit commitment model, because these reserves are not sourced from thermal units.

during the horizon of the study. Since the strategic reserve was not mobilized during the interval of the new study, neither in the day-ahead market or in real time, we remove the strategic reserve units from the simulation in order to accurately model the commitment and dispatch of the remaining fleet, however we account for the availability of strategic reserve when computing adders as the sole existence of these capacities in reserve indeed implies a modification of the LOLP. The units that were available as strategic reserve for 2015 included[4] Seraing (485 MW), Vilvoorde (265 MW), Angleur (50 MW), Izegem (20 MW) and Esche-sur-Alzette (357.1 MW), as well as 358.4 MW of demand response, thereby totaling a strategic reserve capacity of 1535.5 MW.

The original study partitioned generators into three categories: (i) Non-dispatchable resources which do not react to price, the output of these resources is based on historical data. These include nuclear (6078 MW), wind power (978 MW), waste (320 MW) and water (93 MW). (ii) Dispatchable resources which are approximated through an affine supply function. We use the same parameters for the affine supply function approximation as in the original study. These resources include blast furnace (323 MW), non-wind renewable resources (106 MW), gas-oil (5 MW), and turbojet (212 MW). (iii) Resources represented through a unit commitment model. These include coal (764 MW) and CCGT (4365 MW, not including the strategic reserve units).

Pumped hydro resources are modeled by optimizing the pumping and production of hydro power over the horizon of one day. We use equal production and pumping capacity for the pumped hydro resources. We assume that pumped hydro reservoirs are completely empty every day at midnight.

We simulate the system operation by solving for the optimal commitment and dispatch of the system with a one-month horizon, in order to avoid border issues with the end and beginning of each day.

We assume that all types of reserve, including primary reserve, are offered with daily resolution. We have observed that changing the resolution of reserve capacity decisions from monthly to daily granularity has significantly accelerated the solution time of the mixed integer linear programs that solve the monthly system scheduling problem. This is expected, because the temporal coupling among consecutive days is weakened, thereby resulting in daily scheduling problems that are nearly independent of each other. Consequently, we no longer employ the receding horizon heuristic that was used for the resolution of the unit commitment problem with monthly horizon in the original study. We use a relative optimality gap of 10^{-5} for the resolution of the unit commitment model.

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[4] http://www.creg.be/fr/producte9.html

4. PRODUCTION SIMULATION RESULTS

This section reports on the results of the model applied under the baseline scenario as well as the various what-if scenarios that were suggested by CREG.

4.1 Restoration of Nuclear Capacity

The profits reported in this section are computed by adding up the simulated profit over the seven months of the study, and dividing by the number of hours in the study times the capacity of each unit. The reported profits are obtained after subtracting a fixed operating and maintenance cost of 7.04 \$/kW-year (EIA 2012 estimate). The running investment cost of CCGT units is estimated at 5.6 €/MWh. 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 a rate of return of 8%, and an investment horizon of 25 years. These assumptions are based on the previous study (Papavasiliou and Smeers, 2017). The units in the present paper are numbered so that they correspond to the results reported in the original study, meaning that CCGTi in the present paper corresponds to CCGTi in the original study.

In order to test for the possibility that the adder may not fully back-propagate to forward markets, we report results for two boundary cases. In the first case, we compute generator revenues assuming that the adder fully back-propagates to the day-ahead time frame, and is therefore also applied to the entire amount of day-ahead transactions. We also report results for the case where the adder does not back-propagate to the day-ahead price, and is therefore only applied to the change of generator output from the day ahead to real time.

In table 2, three CCGT units have been removed from the original fleet, since they have been moved to strategic reserve: Seraing, Vilvoorde, and Esche-sur-Alzette. From the results of the table, one can conclude that: (i) all CCGT units attain profits that are comfortably above their hourly equivalent investment cost, and (ii) the impact of the ORDC adder on generator profitability is negligible. The average adder over the duration of the study amounts to 0.3 €/MWh. This indicates that, in conditions of abundant capacity resulting from the restoration of nuclear capacity, the ORDC adder has a negligible effect on energy prices, which is compatible with the adaptive nature of the adder.

The fact that the profits of CCGTs are improved compared to the original round of simulations (January 2013 – September 2014) is a consistent observation for all cases that were tested in the new

Table 2

Profitability of CCGT for the reference case of the new study (with nuclear plants restored). Profits are reported without ORDC price adders (second column), with ORDC adders that do not back-propagate to the day-ahead market (third column), and with ORDC adders that fully back-propagate to the day-ahead market (fourth column).

	Profit no adder (€/MWh)	Profit with adder no back-propagation (€/MWh)	Profit with adder full back-propagation (€/MWh)
CCGT1	10.6	10.6	10.8
CCGT2	9.2	9.3	9.4
CCGT3	9.8	9.8	10.1
CCGT5	9.5	9.5	9.8
CCGT6	9.2	9.2	9.4
CCGT8	9.4	9.4	9.7
CCGT9	11.0	11.0	11.3
CCGT11	9.2	9.2	9.4

Table 3

Utilization rates (in %) of CCGT units, expressed as the fraction of average output to available capacity.

	Original study	New study
CCGT1	55.2	58.3
CCGT2	14.0	48.5
CCGT3	71.1	73.2
CCGT5	52.1	58.2
CCGT6	31.7	46.6
CCGT8	46.1	55.7
CCGT9	69.1	69.5
CCGT11	18.7	62.3

study. There are two factors that are notably different in the new study, compared to the old study, and which might contribute to this observation: (i) there is a notable drop in natural gas prices, as indicated in figure 3, which is the data source for our study[5]; (ii) the average CCGT capacity which is active in the energy market has dropped since Vilvoorde, Seraing and Esche have moved to strategic reserve and a certain amount of CCGT capacity has been scrapped. The first factor is clearly favorable for the profitability of CCGT units, since it reduces their variable costs. The second factor could also be argued to favor CCGT units, since it relieves competitive pressure and opens up market share for the surviving CCGT units. This interpretation is further supported by the comparison of the utilization rates of CCGT units in table 3. Note that *all* units increase their utilization rates, and for some units this increase is quite significant (for example, CCGT2 and CCGT11 increase their utilization rate more than threefold).

Note that the CCGT capacity retired from the energy market comprises plants that are effectively

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[5] https://my.elexys.be/MarketInformation/SpotZtp.aspx

Figure 3: The evolution of natural gas prices (source: SpotZTP). The dashed line indicates the beginning of the study interval, which runs from September 2015 until March 2016. Note that the price of natural gas in the study interval is at its lowest value since October 2012.

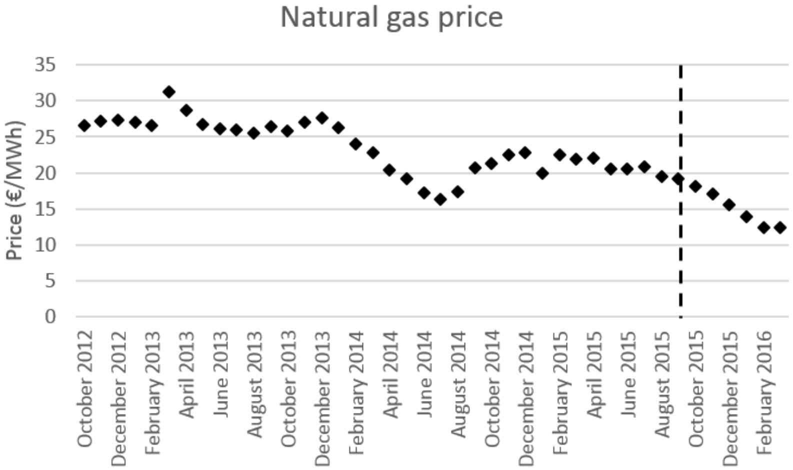


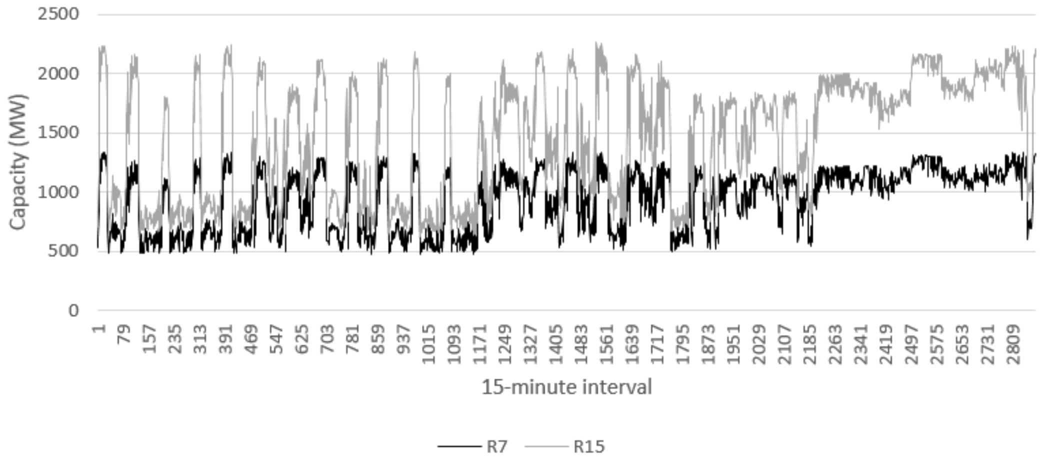
TABLE 4

Profitability of CCGT for the case without strategic reserve. Profits are reported without ORDC price adders (second column), with ORDC adders that do not back-propagate to the day-ahead market (third column), and with ORDC adders that fully back-propagate to the day-ahead market (fourth column).

	Profit no adder (€/MWh)	Profit with adder no back-propagation (€/MWh)	Profit with adder full back-propagation (€/MWh)
CCGT1	10.6	10.6	15.2
CCGT2	9.2	9.3	12.6
CCGT3	9.8	9.8	14.6
CCGT5	9.5	9.5	14.1
CCGT6	9.2	9.3	12.8
CCGT8	9.4	9.4	13.9
CCGT9	11.0	11.0	15.8
CCGT11	9.2	9.2	13.2

dismantled and others that joined the strategic reserve. The latter units provide services to the TSO: they contribute to keeping the adder low but have no impact on the energy price. In contrast, the removal of plants from the system (energy market and strategic reserve) increases the adder and the price on the energy market. The following section further explores the role of these reserve plants by investigating the impact of fully retiring them[6].

Figure 4: The available capacity in 7.5 minutes and 15 minutes for December 2015 for the case without strategic reserve.



4.2 Impact of Strategic Reserve

The first what-if scenario requested by CREG was to test the impact of removing strategic reserve capacity on scarcity prices. The strategic reserve is a particular version of capacity mechanism. Its principle is that the TSO procures the services of additional reserve capacities on top of those available from the energy market, when it evaluates the capacities necessary for meeting peak demand in the coming years[7]. Notwithstanding its introducing strategic reserve in 2014, Belgium has not at this stage (as of July 2017) notified the mechanism to EU Competition Authorities, with the result that one does not know whether it will be approved on time for contracting the plants before the peak of next winter[8].

In this round of simulations we remove the strategic reserve from the system for the months of November 2015 – March 2016. The removal of the strategic reserve has a noticeable impact, especially during the winter months. The average value of the adder is 4.4 €/MWh, compared to 0.3

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[6] The intermediate status of the strategic reserve between commercial and dismantled may have a counterpart in the market: one indeed sees “infrastructure companies” acquiring distressed capacities from utilities in order to obtain the option of intervening in times of scarcity (“Blackstone Does what RWE Can’t Do by Reviving Dutch Plant”, Bloomberg July 7th, 2017). In physical terms, these plants will intervene in the energy market when the system is tight, which is when the ORDC adder effectively becomes active.

[7] Plants that owners would dismantle because of economic conditions are obvious candidates to be part of the strategic reserve. The TSO determines the needed capacity on the basis of a probabilistic study (LOLE evaluation) conducted on different scenarios of demand and capacity availability in the Belgian and neighboring systems (see ELIA (2017) for the 2017-2018 planning). The analysis is conducted using computational tools developed by RTE (the French TSO) based on Monte Carlo simulation of unit commitment problems. The retained plants are selected together with other instruments in an auction.

[8] It is not even clear that the Commission will approve the mechanism: the Commission is currently investigating a German proposal for strategic reserve (“State aid: Commission opens in-depth investigation into German plans for electricity capacity reserve”. European Commission, Brussels, April 7, 2017) and some of the preliminary objections made in that case could be repeated for Belgium. We do not know at the time of this writing what the decision of the Commission will be for Germany.

€/MWh for the base case. The amount of capacity that can be made available in 7.5 and 15 minutes is presented in figure 4. The impact of the adder is noticeable when there is full back-propagation of the adder. The CCGT profit results are reported in table 4. Without back-propagation, the impact of the adder on profits remains negligible, despite the elevated adder. The impact of retaining the strategic reserve on generator profits therefore drastically depends on the extent of back-propagation. This difference of impact is however much higher than in table 2 for the reference scenario, where the impact of the adder remained negligible irrespectively of back-propagation.

Recall that the absence of back-propagation corresponds to the case where the adder only applies to real-time transactions: because the remuneration of the CCGTs in day-ahead energy is unchanged, the global impact in the energy market remains negligible. In contrast, the adder applies to all transactions in case of back-propagation, leading to profits that are significantly higher than the investment cost and are likely to be considered as excessive. This may lead one to question the back-propagation of the adder. In order to justify back-propagation, we take stock of the recommendations of the European Commission. We first note that ORDC, being a demand for operating reserve, conceptually deals with capacity. It results in an adder that is a payment to the “mere availability of generation capacity”, as stated in paragraphs 218, 219 and specially 225 of the European Commission guidelines on State Aid (European Commission, 2014). It does not include any remuneration for the delivery of energy (paragraph 225): the adder does not involve energy but is added to the remuneration of the energy for the generating plants; it stands alone for the non-generating plants. This remuneration is obtained by a “clearly defined” instantaneous LOLP computation, which is one of the methods recognized by the Commission for measuring insufficient capacity[9]. The mechanism then only applies “when and where” necessary (paragraph 221), in the sense that it depends on the instantaneous available capacity and demand . It applies to all plants, whether conventional or renewable, provided that they provide the same capacity services (paragraph 226). Moreover, the remuneration goes to zero when capacity is sufficient (paragraph 231). Back-propagation is implicitly imposed by paragraph 225 of the guidelines, because the remuneration is due to all plants for their availability, regardless of whether this availability is committed in real time or in the day-ahead time frame.

The remaining question is whether ORDC does not inflate the remuneration beyond what is necessary, possibly leading to windfall profits which would violate paragraph 230. Our first paper did not lead to windfall profits under high gas prices with back-propagation and a high adder. This paper does not show windfall profits with low gas prices and back-propagation (since the ORDC

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[9] See footnote 93 or paragraph 218 of (European Commission, 2014), section 3 of European Commission (2015), and (European Commission, 2016).

adder is near-zero in the case where strategic reserve is kept). The question is then to explain why back-propagation leads to windfall profits in case the reserve capacity is not implemented and some generators move forward with their threat of closing down the plants that were supposed to be included in the strategic reserve. The response is that the closing of these plants has lead to a shortage of capacity which is not justified on economic grounds. It occurred as a reaction to a misleading signal sent by the market, where plants have not been remunerated for their availability[10]. Effectively, paragraph 225 of the Commission guidelines on State Aid (European Commission, 2014) is not applied in the current market design (which does not remunerate the plants for the availability of their capacity except for those of the strategic reserve). The windfall profits are thus the result of an excessive dismantling due to the fact that the capacity mechanism is implemented without some of its requirement, namely the equal remuneration (back-propagation) of available capacity, independently of whether it is placed in strategic reserve or not. As shown in table 2, the windfall profit disappears if the reserve capacity is retained, back-propagation is applied, and plant owners have no incentive to anticipate their retirement.

The next section shows that this reasoning, which is based on existing European Commission legislation (European Commission, 2014), can be directly related to the economics of the mechanisms implemented in US markets.

4.3 Back-propagation and forward markets in EU and US market designs

ORDC is based on the principle that the adder should back-propagate. This derives from first principles: scarcity in equipment capacity or quality (e.g. flexibility) is a system-wide phenomenon that is only observable in real time during system operations. ORDC instantaneously converts real-time physical scarcity to energy curtailment probability that it values through standard notions of unserved energy and VOLL. Besides real time there is no spot market in the system and hence there cannot be any other spot price: all other meaningful prices should ideally be forward prices. The only valid economic interpretation of those day-ahead prices is that they are forward prices. The adder should thus apply to all transactions, either directly in real time or through forward prices in the day ahead. This is what back-propagation means. This principle underpins all US restructured markets, that also provide a mechanism (virtual trading (Hogan, 2016)) for making the day-ahead market as close as possible to a forward market[11].

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[10] See EDF Luminus statements in “Libre Belgique” of August 23, 2017, http://www.lalibre.be/economie/libre-entreprise/les-neufs-candidats-a-la-reserve-strategique-d-electricite-rejetes-599c743acd706e263f89d9d8.

[11] Section II in Potomac (2017) and Potomac (2016) document the extent to which day-ahead prices are effectively forwards of real-time prices in ERCOT. The graphs illustrate and the discussions explain the convergence that makes day-ahead prices

As discussed by Papavasiliou and Smeers (2017), the importance of real-time signals is well recognized by European competition authorities but the European market is not organized accordingly. No particular attention is given to real-time price signals in the current design and the day ahead is considered as the spot market for the sole reason that it captures the bulk of the transactions. In order to resolve the contradiction of a spot market that clears on expectations of spot transactions and not on the transactions themselves, the day-ahead market is followed by intraday markets in order to enable actors to adjust to additional information arising between day ahead and real time. Intraday markets may therefore naturally evolve into spot markets in European market design when they becomes more liquid[12]. Notwithstanding, real time is conceived as a balancing mechanism that agents are encouraged to avoid and not as a real-time market that could price scarcity. There is also no mechanism intended to convey real-time signals to the day ahead. The best that one can thus hope for given the existing EU design is to back-propagate scarcity in the day ahead, allowing agents to include the opportunity cost of real-time corrections in their day-ahead bids. However, this goes against the fundamental principles of scarcity pricing. This is a subject in itself, which suggests that the role of balancing in European market design will need to be revisited.

4.4 Impact of VOLL = 8300 €/MWh

In this case we retain the assumptions of the base case, and employ a VOLL of 8300 €/MWh, instead of a VOLL of 3000 €/MWh, for the computation of the adder. The average adder amounts to 0.7 €/MWh, as compared to 0.3 €/MWh in the base case. The profitability of CCGT units is listed in table 5. Similar conclusions apply as in the previous scenarios: the inability of the adder to back-propagate implies that the adder has a negligible impact on generator profits, whereas the full back-propagation of the adder has a noticeable impact on generator profits. The impacts, on the adder, of the increase in VOLL are less pronounced than the impacts of removing strategic reserve.

5. IMPACT OF IMBALANCE CORRELATIONS ON ORDC ADDERS

ORDC as well as the sizing of strategic reserve are based on reliability computation of the LOLP type. The software ANTARES of the French TSO RTE (ELIA, 2017), which underpins the analysis

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expectations of real-time prices. The virtual trading mechanism that underpins that property is effectively implemented in ERCOT as well as in other restructured US ISOs.

[12] However, this is difficult to imagine, given that these markets are organized in different ways. Abbassy et al. (2010) discuss a case that is still far from back-propagation in the sense of a forward market. The situation may have evolved and an analysis of intraday trading would in any case require a study that goes well beyond the scope of this paper. One can finally conclude that convergence will not occur in markets where balancing is organized on the basis of different up and down prices which depend on whether the system is short or long.

Table 5
Profitability of CCGT for the case with VOLL = 8300 €/MWh. Profits are reported without ORDC price adders (second column), with ORDC adders that do not back-propagate to the day-ahead market (third column), and with ORDC adders that fully back-propagate to the day-ahead market (fourth column).

	Profit no adder (€/MWh)	Profit with adder no back-propagation (€/MWh)	Profit with adder full back-propagation (€/MWh)
CCGT1	10.6	10.6	11.2
CCGT2	9.2	9.3	9.8
CCGT3	9.8	9.8	10.6
CCGT5	9.5	9.5	10.3
CCGT6	9.2	9.2	9.8
CCGT8	9.4	9.4	10.2
CCGT9	11.0	11.0	11.8
CCGT11	9.2	9.2	9.9

of the Belgian TSO for strategic reserve, models plant availability through hourly constant levels. There is today a growing interest in the analysis of the fine time structure of ramping calls in markets with an increasing penetration of renewable resources; this enables representing a more dynamic behavior of plants by describing plant operations over shorter time intervals. ORDC implemented in ERCOT works on a time resolution of 30 minutes decomposed in two successive periods of 15 minutes to represent differences of plant flexibility, which makes it possible to model some of the reserve dynamics. We similarly work on 15-minute time granularity, which is the granularity of the balancing intervals in the Belgian system, and which is decomposed into two successive periods of 7.5 minutes, corresponding to the response times of secondary and tertiary reserve in Belgium.

ERCOT models a call on reserve by a normal distribution at the end of each balancing interval, from which it derives the ramping call after the first half of the balancing interval by a proportionality rule. The demand for reserve in the two halves of the balancing interval is thus determined by a single random draw for each balancing interval: the two calls on reserves are thus perfectly correlated. Papavasiliou and Smeers (2017) assume an independent normal distribution for the ramping call for each half of the balancing interval, where the demand for the entire balancing interval is the sum of the demands in the two halves of the balancing interval. The two calls on reserves are thus perfectly independent. These are just examples that provide a starting basis for analysis. Solar and wind generation are increasingly represented by stochastic processes or ramping events that can adapt to finer time granularity and enable more sophisticated cross-interval dependency. Because this study works with two types of reserve of different flexibility (full response in 7.5 minutes or 15 minutes), we examine the possible correlation of the demand for reserves in these two successive intervals and

Figure 5: The scatter plot of imbalance at the 15-minute interval t versus imbalance at the 15-minute interval $t - 1$.

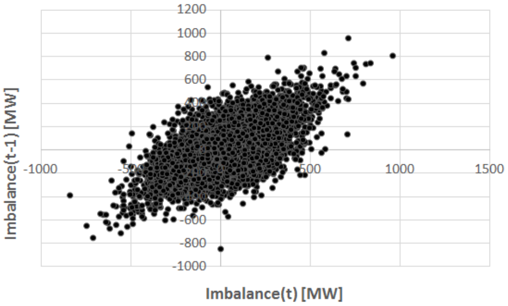
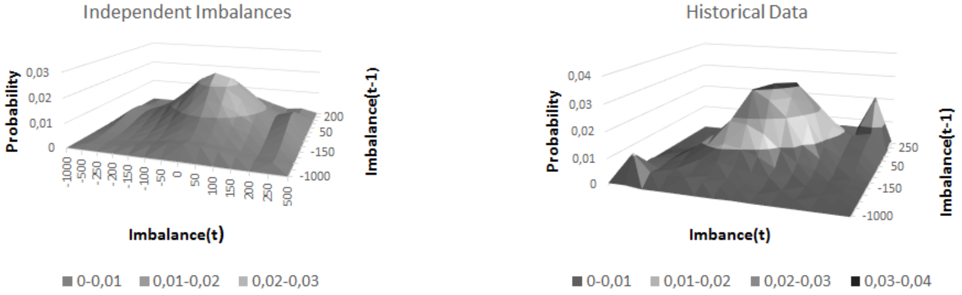


Figure 6: The probability density function of imbalances in consecutive time periods under the assumption of independent imbalances (left panel), and based on the observed data.



their impact on the adder.

5.1 Evidence of Positive Correlation of Imbalances

Figures 5 and 6 present the results of the analysis on the system imbalance metering signal provided to us by CREG for the duration of the study interval. The system imbalance metering signal is provided at a 15-minute resolution. Figure 5 indicates a strong positive correlation, with the correlation coefficient for imbalances in consecutive time periods amounting to 0.642.

The left panel of figure 6 presents the probability density function of consecutive imbalances X_t that would be obtained if imbalances would be independent and identically distributed according to the *marginal* empirical distribution of $\mathbb{P}[X_t]$ derived from the data. The right panel presents the *joint* probability density function of $\mathbb{P}[X_{t-1}, X_t]$, as observed in the data. If consecutive imbalances were indeed independent, the two density functions should exhibit some similarity. This is clearly not the case, since the figure on the right panel concentrates significant probability mass on the upper right and lower left corner of the support. This implies that large positive (respectively negative) imbalances are likely to be followed by large positive (respectively negative) imbalances.

5.2 Accounting for Positive Correlations in ORDC Adder Computations

The positive correlation among consecutive imbalances suggests that the scarcity adder computation should be adjusted accordingly. In particular, we are interested in how the positive correlation of imbalances affects the interplay between the 7.5-minute and 15-minute components of the total adder in equation (1).

We propose and analyze three different approaches towards computing $LOLP_{7.5}(R_{7.5})$, the loss of load probability in a 7.5-minute horizon given that a capacity of $R_{7.5}$ can respond within 7.5 minutes: (i) fully independent increments of imbalance (Papavasiliou and Smeers, 2017); (ii) fully correlated increments of imbalance (Hogan, 2013); (iii) increments of imbalance which are calibrated against the empirically observed correlation. The third case is an intermediate of the boundary cases (i) and (ii). For all cases, it is assumed that the 15-minute uncertainty, X_t, is distributed as a normal distribution with mean μ_{15} and standard deviation σ_{15}.

Fully independent increments of imbalance. This approach assumes that the 15-minute uncertainty X_t is the sum of independent identically distributed normal random variables. In other words, the increments of imbalance in 7.5 and 15 minutes are assumed to be perfectly uncorrelated. The 7.5-minute imbalance is thus obtained as a random variable with a distribution $N(\frac{1}{2}\mu_{15}, \sqrt{\frac{1}{2}}\sigma_{15})$, where $N(\cdot)$ denotes the normal distribution. The 7.5-minute contribution to the scarcity adder in equation (1) is computed as:

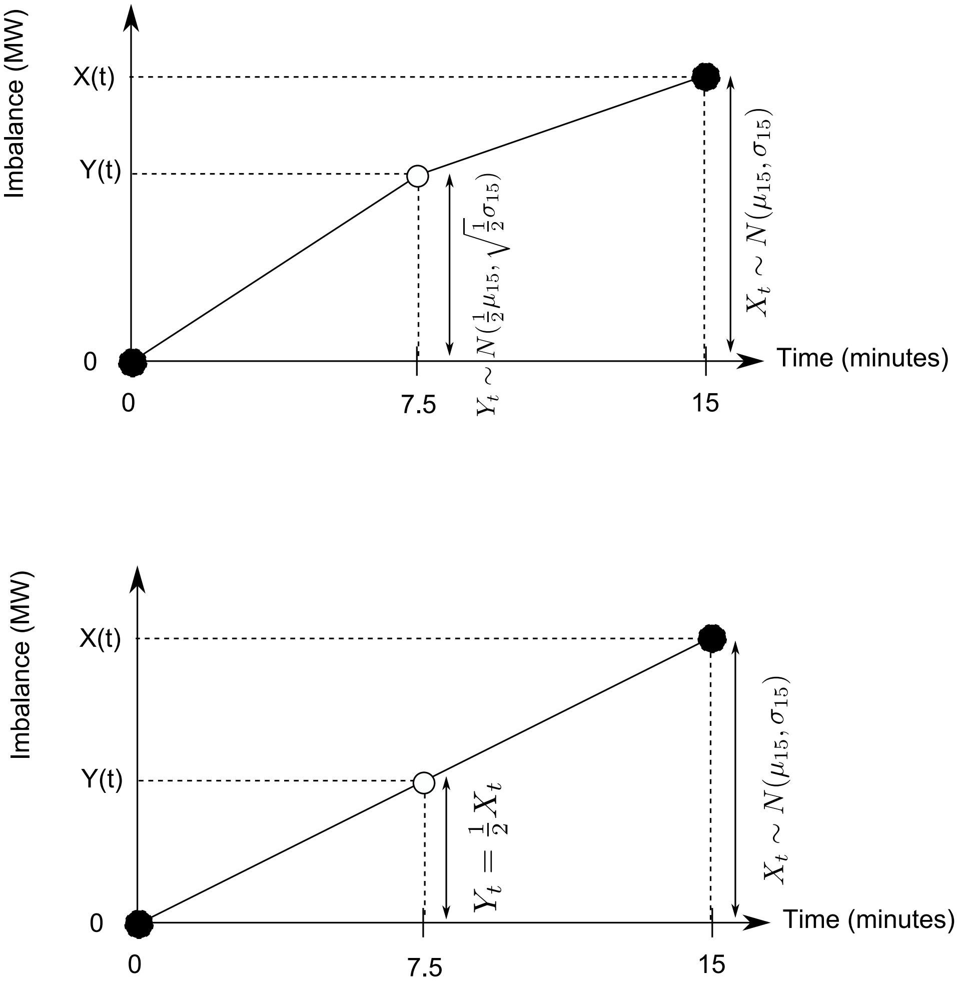
$$\begin{aligned} & LOLP_{7.5}(R_{7.5}) = \mathbb{P}[R_{7.5} < Y_t] = 1 - \mathbb{P}[R_{7.5} \geq Y_t] = \\ & 1 - \mathbb{P}[\frac{R_{7.5} - \frac{1}{2}\mu_{15}}{\sqrt{\frac{1}{2}}\sigma_{15}} \geq \frac{Y_t - \frac{1}{2}\mu_{15}}{\sqrt{\frac{1}{2}}\sigma_{15}}] = 1 - \Phi(\frac{R_{7.5} - \frac{1}{2}\mu_{15}}{\sqrt{\frac{1}{2}}\sigma_{15}}), \end{aligned} \tag{2}$$

where Y_t is the 7.5-minute imbalance of interval t, and $\Phi(\cdot)$ is the cumulative density function of the standard normal distribution.

Fully correlated increments of imbalance. This approach assumes that the 15-minute imbalance X_t is the result of a linear evolution of the imbalance. In other words, the increments of imbalance are assumed to be perfectly correlated. The 7.5-minute contribution to the scarcity adder in equation (1) is computed as:

$$
\begin{aligned}
&LOLP_{7.5}(R_{7.5}) = \mathbb{P}[R_{7.5} < Y_t] = 1 - \mathbb{P}[R_{7.5} \geq Y_t] = \\
&1 - \mathbb{P}[R_{7.5} \geq \frac{1}{2}X_t] = 1 - \mathbb{P}[2R_{7.5} \geq X_t] = \\
&1 - \mathbb{P}[\frac{2R_{7.5} - \mu_{15}}{\sigma_{15}} \geq \frac{X_t - \mu_{15}}{\sigma_{15}}] = 1 - \Phi(\frac{2R_{7.5} - \mu_{15}}{\sigma_{15}}).
\end{aligned} \tag{3}
$$

Figure 7: The upper panel corresponds to independent increments: the imbalance in the 7.5-th minute is a Gaussian random variable with mean $\frac{1}{2}\mu_{15}$ and standard deviation $\sqrt{\frac{1}{2}}\sigma_{15}$. The lower panel corresponds to fully correlated increments: the imbalance in the 7.5-th minute is obtained as $Y_t = \frac{1}{2}X_t$.



The distinction between cases (i) and (ii) is presented in figure 7. The essential difference is that lower correlation between the increments of imbalances implies a higher variance for 7.5-minute imbalance Y_t, *given* a certain standard deviation σ_{15} for the 15-minute imbalance X_t. Said otherwise, approach (ii) will result in lower 7.5-minute adders than approach (i), since in order to get a certain standard deviation σ_{15} for 15-minute imbalances X_t, it is necessary to have a higher variance for the 7.5-minute imbalance Y_t for the case of independent increments than for the case of fully correlated increments.

Partially correlated increments of imbalance. The third approach that we consider is an intermediate case between approaches (i) and (ii), for which we use empirical data in order to fit a conditional distribution that describes the dependence between consecutive imbalance increments. Specifically, we use kernel density estimation for estimating $G(\delta|x) = \mathbb{P}[\Delta_t \leq \delta|X_t = x]$, the cumulative distribution function of $\Delta_t = W_t - Y_t$ conditional on X_t, where W_t is the increment of imbalance from minute 7.5 to minute 15 for a given imbalance interval t. The detailed explanation of kernel density estimation is provided in the appendix. Once the function $G(\cdot)$ has been estimated, we proceed with the computation of the new adders, which account for the correlation of the imbalance increments. Conditioning on the realization of the 15-minute imbalance, X_t, we obtain the following:

$$\begin{aligned}
&LOLP_{7.5}(R_{7.5}) = \int_{-\infty}^{\infty} \mathbb{P}[Y_t \geq R_{7.5}|x]\mathbb{P}[X_t = x]dx = \\
&\int_{-\infty}^{\infty} \mathbb{P}[\Delta_t \leq x - 2 \cdot R_{7.5}|x]\mathbb{P}[X_t = x]dx = \\
&\int_{-\infty}^{\infty} G(x - 2 \cdot R_{7.5}|x)\phi(\frac{x - \mu_{15}}{\sigma_{15}})dx \qquad (4)
\end{aligned}$$

where $\phi(\cdot)$ represents the probability density function of the standard normal distribution. The second equality is obtained by observing that $\Delta_t = W_t - Y_t$ and $X_t = Y_t + W_t$ by definition. Note that the processes X_t, Y_t, W_t are obtained from the minute-by-minute data of system imbalances, $z_k, k = 1, \ldots, 15$, as follows:

$$\begin{aligned}
X_t &= \frac{\sum_{k=1}^{15} z_k}{15} \\
Y_t &= \frac{\sum_{k=1}^{7} z_k + z_8/2}{15} \\
W_t &= \frac{z_8/2 + \sum_{k=9}^{15} z_k}{15}
\end{aligned}$$

5.3 Comparison of Scarcity Adder Values

We conduct an analysis on the impact of correlations to the adder computation using net regulation value (NRV) data[13]. We have access to NRV data with 1-minute resolution. We use data from June

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[13] The NRV data are a measure of net capacity shortfall which is available in the ELIA website with 1-minute resolution (as opposed to the net capacity shortfall data that was provided by CREG with hourly resolution for the original study). NRV data exhibit a similar positive correlation as the one observed in figures 5 and 6. The net regulation volume is found in the following

Table 6
ORDC adders computed using (i) independent increments of imbalance (equation (2)), (ii) fully correlated increments of imbalance (equation (3)), and (iii) partially correlated increments of imbalance (equation (4)). All values are in €/MWh.

	Independent	Correlated	KDE	15-minute contribution
Reference	0.47	0.26	0.26	0.25
No SR	3.18	1.88	1.89	1.84
VOLL 8300	1.35	0.74	0.75	0.72

2015 until November 2016 for the calibration of the probability density functions used in equation (1).

The ORDC adders are presented in table 6. The second, third and fourth column present the total adder for the three different methods discussed in the previous section. The fifth column presents the contribution of the 15-minute adder to the total adder. There are two major conclusions from this analysis. (i) The two boundary approaches of fully correlated and fully independent imbalances produce notably different results. The fully independent approach tends to result in higher adders, because given a certain level of 15-minute standard deviation it implies a higher level of 7.5-minute standard deviation. (ii) The partially correlated approach produces results that are intermediate between the independent and fully correlated approach, but rather closer to the fully correlated approach. This is due to the strong correlation of consecutive imbalances which has already been noted in figures 5 and 6. Note that the 15-minute adder has the greatest contribution to the total adder.

The fact that the fully correlated approach and the KDE approach produce nearly identical results suggests that the simplicity of the fully correlated approach of equation (3) would make it preferable in terms of practical implementation.

6. CONCLUSIONS AND PERSPECTIVES

The major observations stemming from the production simulations can be summarized as follows: (i) CCGT units appear to be able to cover their investment costs over the studied period, possibly due to the drop in natural gas prices and reduced competition due to the elimination of CCGT capacity. (ii) The adders are negligible during the study period, when strategic reserve is kept in the capacity mix (average adders amount to 0.3 €/MWh). (iii) The removal of strategic reserve from the capacity mix has an important impact on adders (average adders amount to 4.4 €/MWh). (iv) The increase of VOLL from 3000 €/MWh to 8300 €/MWh has a lesser impact on adders than the removal of strategic reserve (average adders amount to 0.7 €/MWh) Whether a strategic reserve should be allowed or not is obviously a decision of European authorities. But in both cases, the adder should apply to all

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address: http://www.elia.be/en/grid-data/data-download. Under the balancing tab, select activated energy volumes.

available capacity as a remuneration for its availability, in compliance to the EU guidelines.

We find that there is a significant positive correlation among consecutive values of imbalances. We analyze two boundary approaches towards estimating the LOLP, which correspond to fully independent increments of imbalance and fully correlated increments of imbalance. These approaches result in considerably different values of ORDC adders, due to the fact that for the same level of standard deviation in 15-minute uncertainty they imply different levels of 7.5-minute uncertainty. We then fit a kernel density function estimator to the difference of imbalance increments based on historically observed data, in order to capture an intermediate scenario between fully correlated and independent increments of imbalance. We find that, due to the strong positive correlations of imbalance increments, the intermediate approach reproduces results that are closer to those of the fully correlated approach.

Our study illuminates certain implementation details which can significantly impact the performance of ORDC pricing. An important question that remains is to investigate how the adder behaves when certain aspects of existing market design are not fully compatible with the theory underpinning scarcity pricing, as is the case in European markets. Future research on the application of the mechanism should therefore focus on determining how the following design choices influence the ability of the ORDC adder to send a long-term investment signal: (i) In case energy and reserves are cleared separately in day-ahead markets, does the timing of day-ahead reserve auctions (before, during, or after energy market clearing) matter? (ii) Is the co-optimization of energy and reserves required in real time? (iii) Is virtual bidding required? These questions are left for future investigation.

APPENDIX

6.1 Kernel Density Estimation

In order to estimate the conditional distribution $\mathbb{P}[\Delta_t | X_t]$ of the difference of imbalance increments Δ_t given the 15-minute imbalance of the interval, X_t, we use kernel density estimation.

The idea of our approach is to customize the distribution of Δ_t not only to the month and the hour of the day (which is the current approach in ERCOT (Hogan, 2013)), but also to the imbalance of the interval, X_t. More specifically, we check how the feature vector x, which consists of three explanatory factors (hour, month, X_t), maps to the output (change in imbalance increments, Δ_t). We do this for the k 'closest' observations in the data, in the sense of the k historical observations of factors x_i whose

Euclidean distance from the current-period conditions is the smallest[14]. This process of selecting the historical data with the closest explanatory factors in order to predict the output of the current period is called the k *nearest neighbors* algorithm in machine learning. We use $k = 1000$ neighbors in the results presented in section 5.

Once the k nearest neighbors of the current interval t have been identified, we use the historically observed imbalance of these neighbors in order to estimate a probability distribution for the change in imbalance increments, Δ_t. For this purpose, we use kernel density estimation (KDE). The basic idea of the KDE estimator is to create a distribution by placing a normal distribution, referred to as a Gaussian kernel, around the historically observed output (change in imbalance increments δ_i) resulting from the explanatory factors x_i of the k nearest neighbors. Mathematically, the kernel density estimator can be described as follows:

$$g(\delta|x) = \sum_{i=1}^{k} \frac{1}{\sqrt{2\pi}\sigma} \exp\left(-\frac{(\delta - \delta_i)^2}{2\sigma^2}\right), \tag{5}$$

where $g(\delta|x)$ is the probability density function of the change in imbalance δ, k is the number of nearest neighbors, σ is a free parameter which determines the width of the Gaussian kernel, and δ_i is the observed change in imbalance increments of the i-th nearest neighbor. The dependence on x, the explanatory factors, is implicit, since the output points δ_i which we choose in order to build the KDE are those of the k nearest neighbors, and therefore depend on the explanatory factors x.

The choice of σ can have a significant impact on the accuracy of the estimation. We use the value of σ proposed by Silverman (1998):

$$\sigma^* = \left(\frac{4\hat{\epsilon}^5}{3n}\right)^{\frac{1}{5}},$$

where $\hat{\epsilon}$ is the standard deviation of the sample data and n is the size of our sample.

The integral of $g(\delta|x)$ is the cumulative distribution function used in the computation of the 7.5-minute adder in equation (4).

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[14] We normalize data so as to have the same standard deviation for the hour and month, and twice the standard deviation for the imbalance.

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