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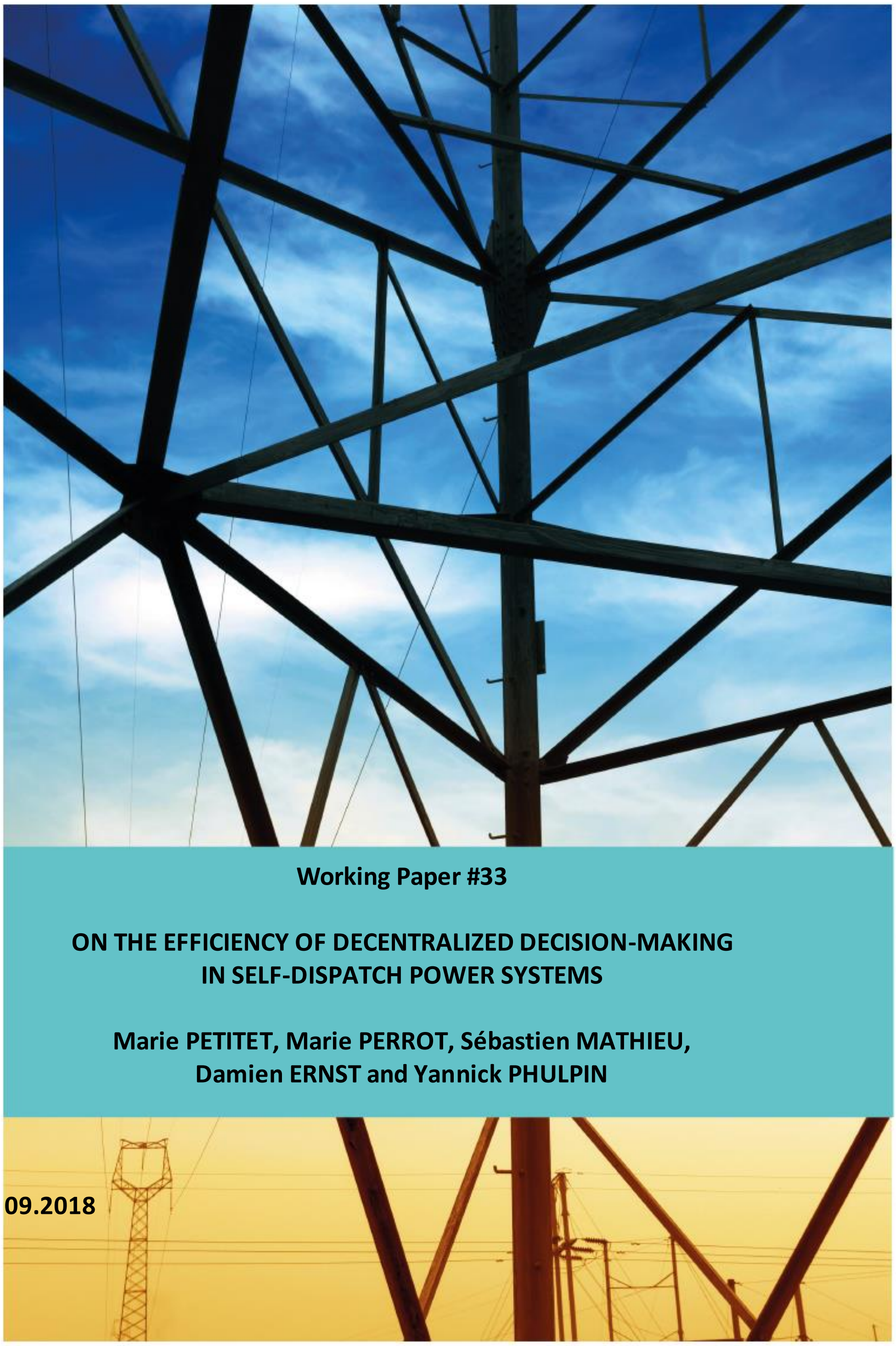

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ON THE EFFICIENCY OF DECENTRALIZED DECISION-MAKING IN SELF-DISPATCH POWER SYSTEMS

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ON THE EFFICIENCY OF DECENTRALIZED DECISION-MAKING IN SELF-DISPATCH POWER SYSTEMS

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Abstract

This paper focuses on market design options for operational balancing management in self-dispatch electric power systems. In particular, it investigates the most relevant timing for the balancing gate closure, when competitors can no longer modify their decisions on the setting of controllable assets and when this responsibility is simultaneously transferred to the system operator. This discussion is central in the development and implementation of the European Electricity Balancing Guideline. Based on a multi-level simulation tool with a realistic modelling of short-term power system operations including informational asymmetry between market participants and the system operator, this paper proposes the first quantitative assessment of reducing the balancing gate closure time from one hour to 15 minutes ahead of the imbalance settlement period. For different environments (energy mix, power plant capabilities, outages, etc…), the results highlight that postponing the balancing gate closure time from one hour to 15 minutes increases the operational cost of the system. Based on robust and scalable results, we show that this difference is mainly due to a better coordination of the available resources by the central decision maker.

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I. INTRODUCTION

Electric power systems evolve towards situations with a major share of generation from intermittent resources where uncertainties on system equilibrium are to be managed thanks to widespread controllable units with a variety of capabilities. In this context, foreseen in [Bunn and Kermer, 2018] for example, the cost efficiency of the power system will depend highly on operational decision making with respect to short-term flexibilities. Operational schemes are generally determined by the regulatory framework in the administrative area. Where multiple areas with diverse regulations are interconnected, economic efficiency motivates the coordination of system operation.

In this regard, the European Union has developed and implemented the Electricity Balancing Guideline [EBGL, 2017]. This allows every Member State to maintain practices conform to local specificities but mandates a strong coordination of the operational schemes used by local System Operators (SO) to activate balancing services (i.e. request more or less injection from available resources) using standard products. This process has raised the problem of setting a balancing gate closure time (BGCT), i.e. when operators of controllable units can no longer change their dispatch planning nor propose balancing services and let the SO take centralized decisions on their activations. Today, the BCGT varies across European countries: for example, it is set to 15 minutes In Germany, Belgium, The Netherlands versus 60 minutes in France and Finland [ENTSO-E WGAS, 2016]. In Europe, the problem has been bound to select between two options [ACER, 2012]: (i) **reactive balancing management**, whereby the BGCT would be set 15 minutes before the beginning of an imbalance settlement period (ISP), or (ii) **proactive balancing management**, with BGCT 60 minutes before the ISP. The opportunity to select a single value for Europe has led to intense debates dominated by theoretical views (e.g. [EFET balancing dream 2017] which is essentially in favor of reactive balancing management) on the ability of energy markets to induce efficient operational decisions. Unfortunately, no party could propose a quantitative assessment of the two options yet [CRE, 2016].

To address this issue, and provide reliable figures to policy makers, we introduce hereafter the first impact assessment of switching the BGCT. The study is based on the multi-level optimization tool SiSTEM that models European short-term electricity markets, covering day-ahead and intraday exchanges as well as balancing activations in real-time, and imbalance settlement. It embeds detailed processes reflecting the most relevant complex dimensions of balancing management in power systems.

Power systems have been studied thanks to various approaches, including optimization models, microeconomic equilibrium models and more recently simulation models. One should refer to [Ventosa et al., 2005] and [Foley et al., 2010] for a review. Among these approaches, optimization and simulation models (in particular agent-based models) are particularly suitable to analyse the short-term functioning of power markets. SiSTEM is a unique combination of the strengths of optimization and simulation aiming at precisely modelling short-term markets, with special care paid to balancing mechanisms and various constraints influencing their outcomes.

We present simulation results corresponding to various situations in terms of generation portfolio, load demand, outages, and capabilities of power plants, and assess for each the system-wide variable costs of serving demand with a system managed in a proactive (i.e. 60-min BCGT) or reactive (i.e. 15-min BCGT) approach. We explain the difference in variable costs based on an in-depth analysis of particular cases and discuss to which extent the results are robust and scalable. Finally, we provide inputs regarding the most relevant gate closure time for balancing.

The paper is organized as follows. In Section 2, we detail the balancing management approaches under consideration according to the Electricity Balancing Guideline and explain the main differences in terms of short-term system operation. Section 3 introduces the simulation tool used for the impact assessment. In Section 4, we present case studies and results in the context of the pending regulatory decisions with respect to balancing management. In Section 5, we discuss more generally our results and provide elements for optimal balancing timing. Section 6 concludes.

II. BALANCING MANAGEMENT IN SELF-DISPATCH POWER SYSTEMS

Balancing management is inherent to self-dispatch[6] power systems, where all network users must name a balance responsible party (BRP), and where only BRPs can trade physical energy on wholesale markets. In this context, the traded energy corresponds to a positive or negative injection in a specific bidding zone, with no differentiation on the type and location of the associated grid units as long as those are located in the bidding zone. This corresponds to the market design in force in a majority of European Member States, e.g. France, Germany, Belgium, the Great Britain. A panorama of actual practices in Europe is provided in [ENTSO-E WGAS, 2016].

To ensure system equilibrium (or limit recourse to ancillary services[7]) in operating self-dispatch power systems, SOs usually require all generators to (i) fix their output ahead of the ISP and (ii) propose balancing services based on their short-term flexibilities. The timing when those requirements apply is generally named BGCT.

We detail hereafter, how schedules are updated ahead and after the BGCT. We acknowledge that this picture is theoretical and does not capture all features of specific contexts. Nevertheless, this design fits with the European Guideline on Electricity Balancing [EBGL, 2017] and includes main options chosen by several European member States.

2.1. Before the balancing gate closure time

Ahead of the BGCT, significant grid units can set their generation schedule conform to their individual forecasts and commitments through markets. In large bidding zones or well-coupled markets, liquidity on day-ahead and intraday markets is relatively high as any flexible resource may be rewarded for updating its output according to energy prices.

Except for congestion management, SOs do not trigger any action likely to affect system balance. They may however contract reserves, i.e. make sure that network users will ultimately offer a minimum volume of balancing services, a few hours/days/months before delivery. Reserve procurement is generally portfolio-based, so that self-dispatch applies ultimately not only to injecting/buying energy but also to selecting the units that will provide balancing services.

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[6] As defined in [EU 2017/2195] and, a self-dispatch power system means that "the generation schedules and consumption schedules as well as dispatching of power generating facilities and demand facilities are determined by the scheduling agents of those facilities".

[7] As defined in [Directive 2009/72/EC], ancillary services correspond to "a service necessary for the operation of a transmission or distribution system". Typically, ancillary services include frequency ancillary services and non-frequency ancillary services such as voltage control.

2.2. After the balancing gate closure time

In some countries, e.g. Germany or France, market parties can still trade energy after the balancing gate closure time. But significant network users can no longer modify their schedule. Liquidity is thus dramatically reduced in energy markets that remain open.

On the other hand, the SO can finally intervene and manage system balance by activating balancing services. It may rely on a variety of products (mainly standard ones which depend on countries but are to be harmonized across Europe in the coming years), and check the effectiveness of services unit by unit, even though bids might be portfolio based.

III. MODELLING SHORT-TERM OPERATION OF SELF-DISPATCH POWER SYSTEMS

To perform the efficiency assessment of different balancing management regimes, we have developed a multi-level simulation model of European short-term electricity markets, covering day-ahead and intraday exchanges as well as balancing activations and imbalance settlement. This model, hereafter named SiSTEM, explicitly represents several power companies and their interactions: each company makes offers, notifies its generation schedule to the SO and ultimately proposes balancing services. After the balancing gate closure, the SO activates balancing energy to restore the balance to the system using all balancing service offers proposed by market participants, including balancing reserves. Imbalance settlement implies bidirectional transactions between the SO and power companies depending on the direction of their imbalance. The simulation is performed sequentially by modelling operational decisions for each time step of the considered period.

The following section details the main actions performed in each time step. A complete description of the model is available in a dedicated publication [Mathieu et al., 2017].

3.1. Differences with respect to pure and perfect competition

Before presenting the modelling and for sake of clarity, this section explains differences between the theoretical reference case of pure and perfect competition with perfect information on the one hand, and the situation modelled in the SiSTEM tool on the other hand.

Under the assumption of pure and perfect competition, among which perfect information and no transaction costs, decentralised markets provide the same result as a benevolent monopoly, i.e. the SO. However, in practice, some elements can explain that real markets differ from this theoretical reference case (e.g. transaction costs, informational asymmetry).

The SiSTEM tool proposes a modelling of electricity markets which aims at being as close as possible to real functioning of self-dispatch power systems. In particular, the informational asymmetry between generation units' operators and the SO is represented. All market participants and the SO have perfect information on the markets' outcomes (day-ahead and intraday markets): volumes and prices are public information. Perfect information is also assumed for past balancing actions taken by the SO.

On the one hand, each market participant forecasts its own portfolio's consumption and electricity generation from its non-controllable units (wind, solar, run-of-river hydropower). This forecast is updated for each simulation time step (i.e. 15 minutes) and the related forecast error decreases in time (see Mathieu et al. (2017) for more details). Based on this information, power companies can estimate the imbalance between their generation, consumption and market exchanges, and trade or update their generation schedule to restore balance. On the other hand, the SO takes balancing decisions based on i) its own forecast of system imbalance, defined as the difference between positive and negative injections at the system scale and ii) balancing bids proposed by the market participants.

We have modelled SO forecasts on system balance in such a way that it does not provide SOs with a competitive advantage against market participants (i.e. the sum of generation minus demand forecasts by market participants tends to be a more accurate view of system balance than the estimation by the SO). However, collecting all balancing bids offers the SO full visibility on the flexibility in the system. Moreover, we consider perfect bids on the intraday and balancing markets: each market participant offer all the flexibility that can be provided by its own production units.

Because of this informational asymmetry between market participants and the proactive SO, we expect that simulations carried out with the SiSTEM tool show differences in terms of efficiency between proactive and reactive balancing management.

3.2. Representation of power companies

Each power company starts by forecasting the consumption of its customers and the non-dispatchable generation of its portfolio. In our model, forecasts are generated from real-life realizations, by overlaying a uniform noise and smoothing the resulting signal.

3.2.1. Generation scheduling

Based on this forecast, and on previous commitments (exchanges with other market parties or reserve contracts), each power company computes its generation schedule. The latter is obtained by solving a unit commitment problem with 15-minute granularity integrating the constraints of thermal generation units, hydro-electric reservoirs and curtailable renewable generation. The thermal unit model integrates traditional unit-commitment constraints, i.e. ramping constraints, start-up/shut down phases and minimum on and off times. The model is enhanced by taking into account notification delays inherent to many thermal units and steady-state constraints imposing a constant power output for a minimum duration. Hydro-electric reservoirs are managed as stocks with various notification delays and time varying bounds and inflows. The latter are given as parameters to integrate long-term management strategies constraints into the short-term management of the water. The value of the stock is linearly dependent on the stock level. Curtailable generation units have no variable cost.

The scheduling model is computationally challenging since it requires optimizing the output of the whole portfolio taking into account the constraints of each generation unit on a potentially large horizon. In practice, the daily scheduled generation planning of the portfolio does not change every minute: it would be too computationally demanding and would need too many human interventions. Scheduling is therefore divided into two parts in the model: short-term and long-term scheduling. They are both performed with the same resolution, i.e. 15 minutes to study finely the impact of balancing. The long-term scheduling allows the integration of day-ahead market exchanges and aims at estimating how to satisfy the demand at lowest cost. The short-term scheduling modifies the scheduled generation planning of assets over the next two hours and is performed in every simulation time step. It is used to take into account the latest accepted intraday market offers, until the final net schedule, and the activation of balancing services. The scheduled generation planning of a power company's asset may vary until the BGCT. Beyond, the generation schedule is considered as fixed and can only be modified when the SO activates balancing offers.

In order to participate to intraday and balancing markets, a power company needs to price its ability to increase or decrease its generated power, given its previous commitments and generation planning. To do so, its scheduled generation planning can be used as reference to compute to which extent the power company can modify its portfolio's injection and at what cost. This information is communicated through explicit offers to the markets. An offer is defined at least by an energy volume over a given period and a maximum price for buying or a minimum price for selling. An offer may span multiple market periods with different energy volumes, allow only binary acceptance and/or be linked to other offers. The offers-building strategy of power companies can either be portfolio-based or unit-based.

3.2.2. Unit-based offers

The flexibility of a single generation unit is given by the difference between the initial generation planning and an alternative planning by either maximizing or market minimizing the energy generation. This energy difference in each trading time step is offered as an independent bid which can be partially accepted at a cost equal to the variable cost of the generation unit, considering start-up cost if necessary. Thermal generation units require making block offers, offers covering more than one trading time step and links between the offers to properly communicate the units' constraints.

3.2.3. Portfolio-based offers

For portfolio-based offers, the power company considers all of its units at the same time to compute its energy-market bids. In this case, offers are generated based on a predefined number of generation scenarios as follows. First, three units-commitments are performed with three different targets: minimum generation, maximum generation and getting as close as possible to the scheduled generation planning. Seventeen intermediate scenarios are generated in between these three scenarios. Units-commitments processed for each scenario provide the closest possible volumes and the associated costs. These volumes and costs are then divided into individual offers for each market time step. The reference scenario is considered as basis to define the flexibility offers and is arbitrarily set to the forecast of the consumption. Volumes above this reference are converted into selling offers. The difference in volume between the first scenario above the reference and the reference volume is offered at the difference of total cost between the two scenarios divided by the difference of volume over the whole horizon. The process is repeated for the next scenarios taking the difference with the previous ones. Sales offers are generated using the symmetric process.

The module computing the offers is used both for the intraday market and to communicate flexibility offers to the SO before real-time. In this model, this flexibility is communicated as explicit offers similar to the one for the day-ahead and intraday markets. Activation of bids is subject to various constraints. Binary decisions, links and exclusions need to be considered. In practice, this complexity is ignored by some SOs and only basic products are considered. In other countries like in France, implicit balancing offers are used. An additional constraint imposes a notification delay before the activation of some bids to ensure the availability of the corresponding generation units.

3.3. Market exchanges

Exchanges in the model first occur with the day-ahead energy market clearing the day before delivery. Typically, the gate closure for submitting bids occurs at 12:00 and results are provided 30 minutes later. In SiSTEM, the clearing of the day-ahead market is formulated as mixed-integer linear program aiming at maximizing the market surplus. This optimization problem is a primal-dual formulation able to simultaneously include constraints on the volumes and prices in the formulation.

After the clearing of the day-ahead market, e.g. at 15:00, the intraday market opens for the next day. In most European countries, the real intraday market is a continuous market where offers are updated continuously by the market participants. In our model, the intraday market is implemented as a series of auctions taking place every simulation time step, i.e. every 15min, using the same formulation of the DA clearing problem. These procedures provide a price for each opened intraday market period at each intraday market clearing. An indicative intraday price is built for a given delivery time step by taking the weighted average over the volumes exchanged in each intraday auctions. We believe that this modelling provides a realistic approximation of the functioning of continuous markets in the real world.

3.4. System operator

The SO ensures the balance between generation and consumption in real time. To this end, it must make sure to ensure that enough balancing services will be proposed by market parties, and therefore contracts balancing reserves. In this study, the amount of reserve that each market party must provide is an input of the simulation tool that does not vary between the investigated scenarios. Power companies include the reserve volumes as a constraint when providing the schedule of their units.

Based on the current system imbalance and on its own forecasts of future imbalances, the SO activates available balancing services partially or totally while respecting notice delays of generation units. In case of reactive balancing management, the SO simply observes the current system imbalance and activates balancing products accordingly. However, in case of proactive balancing management, the SO needs to forecast system imbalance. The imbalance forecasts are done by persistence, based on previous imbalances[8], and do not depend on the more detailed forecasts made by the various power companies. The SO restores balance while minimizing balancing energy cost, considering technical constraints and uncertainties on the future system imbalances. The cheapest offers should be selected to provide upward balancing, while downward balancing is preferably obtained by decreasing the generation of the most expensive asset as of the last schedules. To make its decisions, the SO considers their impact on the future ISPs for which the BGCT is foregone. In SiSTEM, the decisions of the SO are taken following the result of a stochastic optimization problem detailed in [Mathieu et al., 2017].

Balancing activations have a cost which is transferred to power companies via the imbalance settlement mechanism. Before the BGCT, a power company communicates to the SO the schedule of all its significant units, resulting from the latest unit commitment and exchanges. The imbalance of a power company is given by the difference between its realizations and its trades. A positive imbalance, e.g. too much injection, leads to a payment by the SO to the power company proportional to the positive imbalance price. A negative imbalance, e.g. not enough injection, leads to a payment by the power company to the SO proportional to the negative imbalance price. SiSTEM allows defining the imbalance pricing scheme using any function of the balancing activation costs. The default rule is the single price approach currently in force in France and described in [RTE, 2017].

[8] More precisely, the proactive SO forecasts three scenarios of future system imbalances. In the central scenario, the forecasted imbalance for future time step t is defined by persistence method as the average of imbalances observed (or forecasted with the same method) for the five previous time steps (i.e. from $t-5$ to $t-1$).

IV. ASSESSMENT OF PROACTIVE AND REACTIVE BALANCING REGIME

4.1. Methodology

To assess the technical and economic impact of shifting the BGCT in a self-dispatch power system, we have simulated, with SiSTEM, short-term operation of a virtual power systems capturing the complexity of real-world power system, in particular in terms of operational conditions. To refrain the computation burden, we have considered systems with a limited number of assets, but encompassing a wide range of technologies, i.e. renewables, nuclear, gas, fuel, coal, and hydro power plants, and the corresponding operational constraints and outage series. We have limited the simulation to one month with a 15-minute granularity.

We considered as main outcome the overall variable cost of operating the system to satisfy the demand defined as input. This consists essentially of fuel costs, emission costs and stock value for the final stock of water. As emphasized in [Caramanis et al., 1982], in a system with pre-defined demand, this performance indicator is the best proxy of the system's socio-economic welfare: the lower the overall variable cost, the higher the socio-economic welfare.

Because the SiSTEM simulation tool relies on MILP solvers with non-deterministic behaviour, it may lead to slightly different results for two runs with the same setting. This difference is characterized in [Mathieu et al., 2017]. To limit the simulation bias below 0.05% in terms of average overall variable costs, we have therefore performed 30 runs for each case[9]. The assessment presented in Section 4.3 corresponds to the average from the 30 runs.

4.2. Study cases

The study case is designed to be as closed as possible to real functioning of power systems. However, the detailed cost and technical parameters of generation units are based on literature review should not be considered as representative of a specific real power system. In practice, these parameters depend on the context (time, localization, macroeconomic situation, etc.), which may vary with time and location. They are therefore complex to estimate.

4.2.1. Load demand

We consider two types of net demand curves based on French historical data[10]. To obtain the net demand curves, generation from cogeneration and fatal hydroelectric plants are subtracted from the demand curve.

- Winter demand: we used 5% of the typical net load demand in France, corresponding to meteorological conditions from January 3, 2014 through February 3, 2014. This leads to a maximum and minimum net demand of 4.81 GW and 2.65 GW, respectively.
- Summer demand: we used 5% of the typical net load demand in France from June 3, 2014 through July 3, 2014. This leads to a maximum and minimum net demand of 3.04 GW and 1.56 GW, respectively.

[9] We performed 100 runs of the same simulation and compared the overall variable cost on average over the 100 runs and over a limited number of runs. The average value obtained for 30 runs varies from the one of 100 runs by only 0.05%.

[10] Available on eco2mix website provided by RTE: http://www.rte-france.com/en/eco2mix/eco2mix.

4.2.2. Generation constraints

The SiSTEM model allows to represent the functioning of generation units in details. Generation technologies are modelled with the features presented in Table I for nuclear and thermal technologies and in Table II for hydropower. Cost and technical parameters are in line with [IEA and NEA, 2015], [Schröder et al., 2013] and [Schill et al., 2016] for nuclear generation.

Table I. Parameters of the generation technologies in the base case regarding flexibility.

	Variable cost	**Startup cost**	**Power range**	**Ramp rate**	**On time**	**Off time**	**Steady period**	**Notice delay**
	€/MWh	k€	MW	MW/h	h	h	min	min
Nuclear A	10	32	[25;1300]	2400	72	24	120	30
Nuclear B	12	22	[20;900]	1800	72	24	120	30
Lignite	16	15	[15;500]	2400	24	12	120	30
Coal	20	3	[15;300]	210	8	8	60	45
CCGT A	28	2.1	[20;400]	1020	4	4	15	5
CCGT B	30	1	[10;200]	1020	4	4	15	5
OCGT	150	0.5	[10;180]	720	0	0.5	15	30

Each parameter was scaled to represent a standard real-life unit, except for the minimum power that was importantly decrease to take into account the aggregation of various real-life units. As a consequence, start-up costs were scaled accordingly to the minimum power. As OCGTs are used as peaking units, their notice delay is chosen to include the duration to start-up the plant. As a consequence, a reactive SO cannot activate OCGT for balancing, which seems realistic. However, to assess the impact of this assumption, note that we have simulated an alternative flexibility scenario with less flexible gas units. In this case, referred to as "No flex gas", the notice delay is set to 15 minutes for CCGT (A or B types) and to 5 minutes for OCGT. In this context, the SO can activate balancing services from OCGT within 15 minutes whereas CCGT are not able to provide it within this time period.

Table II. Parameters of hydropower units

	Water value range*	**Stock value****	**Minimum power**	**Notice delay**
	€/MWh	€/MWh	MW	min
Hydro manual	[20;120]	50	0	180
Hydro remote	[20;120]	50	0	5

N.B.: * The water value is used for dispatch decisions.
** The stock value is used to value the water stock at the end of the simulation in order to compare two cases with different water uses.

Wind and PV are modelled as non dispatchable generation: the generated volume is defined through their load factor for each simulation time step.

For conventional technologies, we have considered random outages according to the risk level identified as parameter for each generation unit. The series were generated independently for each generation mix considered for the simulations. The outages' series under consideration are fully detailed in Annex A. However, beyond the random outages, planned maintenances are not taken into account.

4.2.3. Generation mix and power companies' portfolios

We have considered two different generation mix characterized by the parameters presented in Table II. The assets are owned by 4 different power companies as detailed in Tables III and IV. Power companies A and B have generating units and consumers in their portfolios whereas power company C is a pure supplier and power company D has the whole renewable production but no consumer. Regarding the definition of the day-ahead market's offers, power company A uses a portfolio-based calculation whereas other companies use unit-based calculation. For all other markets (intraday, balancing), the offers' definition is unit-based.

Table III. Parameters of the generation mix

Mix name	**"Nuclear+RES+Gas"**	**"RES+Coal+Gas"**
Nuclear capacity (GW)	3.10	0.90
Lignite capacity (GW)	0.00	1.00
Coal capacity (GW)	0.30	1.80
Gas capacity (GW)	0.80	1.20
Fuel capacity (GW)	0.36	0.18
Hydro capacity (GW)	0.50	0.00
Wind capacity (GW)	0.50	1.50
PV Capacity (GW)	0.26	2.00

Table IV. Generation and load portfolios of the 4 power companies in the case "Nuclear+RES+Gas".

Power company	**A**	**B**	**C**	**D**
Nuclear A (GW)	1.30			
Nuclear B (GW)	1.80			
Coal (GW)		0.30		
CCGT A (GW)		0.40		
CCGT B (GW)	0.20	0.20		
OCGT (GW)	0.36			
Hydro manual (GW)	0.10			
Hydro remote (GW)	0.40			
Wind (GW)				0.50
PV (GW)				0.26
Winter peak load (GW)	3.59	0.71	0.51	0.00
Summer peak load (GW)	1.16	0.22	0.18	0.00

Table V. Generation and load portfolios of the 4 power companies in the case "RES+Coal+Gas".

Power company	**A**	**B**	**C**	**D**
Nuclear A (GW)		0.90		
Lignite (GW)	0.50	0.50		
Coal (GW)	1.20	0.60		
CCGT A (GW)	0.40	0.40		
CCGT B (GW)	0.20	0.20		
OCGT (GW)	0.18			
Wind (GW)				1.50
PV (GW)				2.00
Winter peak load (GW)	3.59	0.71	0.51	0.00
Summer peak load (GW)	1.16	0.22	0.18	0.00

4.2.4. Summary of the scenarios

The 5 scenarios under consideration are characterized in Table VI. These various scenarios allow to cover a wide range of situations and to estimate the robustness of the results.

Table VI. Description of the scenarios

	Demand	Gen flexibility	Mix	Outage
Scenario A	Winter	Base case	"Nuclear+RES+Gas"	S1
Scenario B	Summer	Base case	"Nuclear+RES+Gas"	S1
Scenario C	Winter	No flex gas	"Nuclear+RES+Gas"	S1
Scenario D	Winter	Base case	"Nuclear+RES+Gas"	S2
Scenario E	Winter	Base case	"RES+Coal+Gas"	S3

4.3. Results

From the social welfare point of view, the efficiency of the balancing management options can be estimated through the overall variable costs to serve the electricity demand profile. More precisely, this overall variable cost includes the variable fuel costs, the start-up costs, the valuation of the hydro stock (50€/MWh) at the end of the test period and the valuation of the energy not served (3,000 €/MWh).

As detailed in Table V, the 60-min BGCT has the lowest overall variable cost in the five considered scenarios. To compare the two BGCT options, we define the cost inefficiency of the 15-min BGCT compared to the 60-min BGCT as the difference in the overall variable cost divided by the one of the 60-min BGGT. This inefficiency rate of the 15-min BGCT, presented in table V, varies from 0.08% to 0.43% in the five considered scenarios.

Table VII. Simulation results in terms of overall variable costs and inefficiency rate.

	60-min BGCT	15-min BGCT	
	Overall variable cost (mean, k€)	Overall variable cost (mean, k€)	Inefficiency w.r.t 60-min BGCT (%)
Scenario A	36,531	36,636	0.29
Scenario B	22,317	22,373	0.25
Scenario C	36,592	36,761	0.43
Scenario D	36,518	36,678	0.43
Scenario E	41,817	41,851	0.08

The differences in overall variable cost observed between 60-min BGCT and 15-min BGCT might be considered relatively low, however as overall variable costs represent significant expenses in real world systems (e.g. approx. 70,000 M€/year to serve 3500 TWh in Europe), a loss of efficiency of 0.3% would correspond to 210 M€/year at European scale.

The difference in overall variable cost between 15-min BGCT and 60-min BGCT (0.1% to 0.4%) persists with various simulation cases and for two different generation mixes. Thus, the fact that 60-min BGCT is more efficient than 15-min BGCT appears as a robust result. We explain this difference by the relative inefficiency of decentralized decisions, based on an incomplete view of the system state, during the last hour ahead real time. Indeed, as presented in section 3.1, SiSTEM model goes further than the theoretical pure and perfect competition by representing new information coming in (forecasting process updated every 15 min) and informational asymmetry between market participants and the SO.

Further investigation has demonstrated that the accuracy of forecast of SOs vs. individual forecasts by power companies cannot explain such a difference. Indeed, as depicted in Table VI, 60 minutes before the ISP, SOs tend to have less accurate predictions than the sum of predictions by the power companies.

Table VIII. Root mean square error (in MW) of SOs and of power companies depending on the time to delivery for Scenario A.

	RMSE (MW) h-1 hour	**RMSE (MW) h-15 min**
Power company 1	46.3	43.8
Power company 2	9.8	8.9
Power company 3	6.5	6.4
Power company 4	5.0	4.8
Sum of power companies' anticipations	51.3	49.1
TSO in the case "60-min BGCT"	65.6	47.0

The greater efficiency of centralized decision-making, between 60 minutes and 15 minutes ahead of the ISP, relates in practice to the lack of coordination between competitors that face uncertainty on their own commitments and do not have any visibility on the flexibility of other market participants. In our simulations, this materializes in practice in numerous activations/de-activations of flexibilities by market parties in the time frame where a proactive SO would have a complete view of available resources to manage the balance (prices, volumes but also notice delays for flexible units and ramping capabilities). The corresponding trades on intraday markets can lead to inefficient operational decisions, in particular for assets with start-up delays over 15 minutes and below 60 minutes. This is illustrated in Figure 1, which depicts both the balancing activations made by the SO and the changes made by power companies during the last hour in the case "15-min BGCT" (either internal changes of the generation schedule, or exchanges through intraday markets) in scenario A. This figure confirms that, as expected, the volume of activations by the SO is greater in the case "60-min BGCT" as the SO faces a higher imbalance (see Table VIII). However, by depicting schedule changes decided by power companies between t-60min and t-15min in the case "15-min BGCT" (see the light blue area in Figure 1), the figure shows that actions taken during the last hour are significantly more numerous in volume in the case "15-min BGCT" than in the case "60-min BGCT".

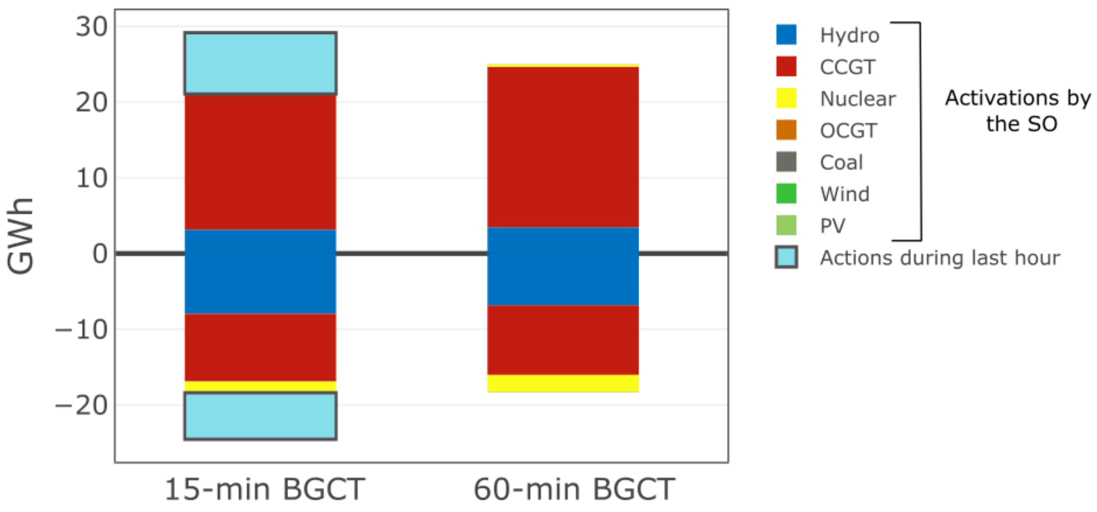

Figure 1. Details on the changes and balancing activations (total over the simulated period – in GWh) during the last hour, in scenario A.

Finally, we note that a 60-minute BGCT generally leads to more balancing energy activations by the SO, which leads potentially to higher "balancing energy costs" as identified by ACER in [Market Monitoring Report]. However, a 15-min BGCT involves many decentralized decisions likely to increase significantly the energy procurement cost in "reactive" balancing management scheme (see light blue area in Figure 1), which should be duly taken into account by policy makers if they intend to maximize social welfare.

4.4. Detailed analysis (scenario A)

This section analyses the results obtained for scenario A in details. As previously mentioned, for each scenario, 30 runs are carried out to ensure the robustness of the analysis. The boxplot of the overall variable cost for "60-min BGCT" and "15-min BGCT" is provided in Figure 2. It confirms the significance and the robustness in the cost difference between the two BGCT options.

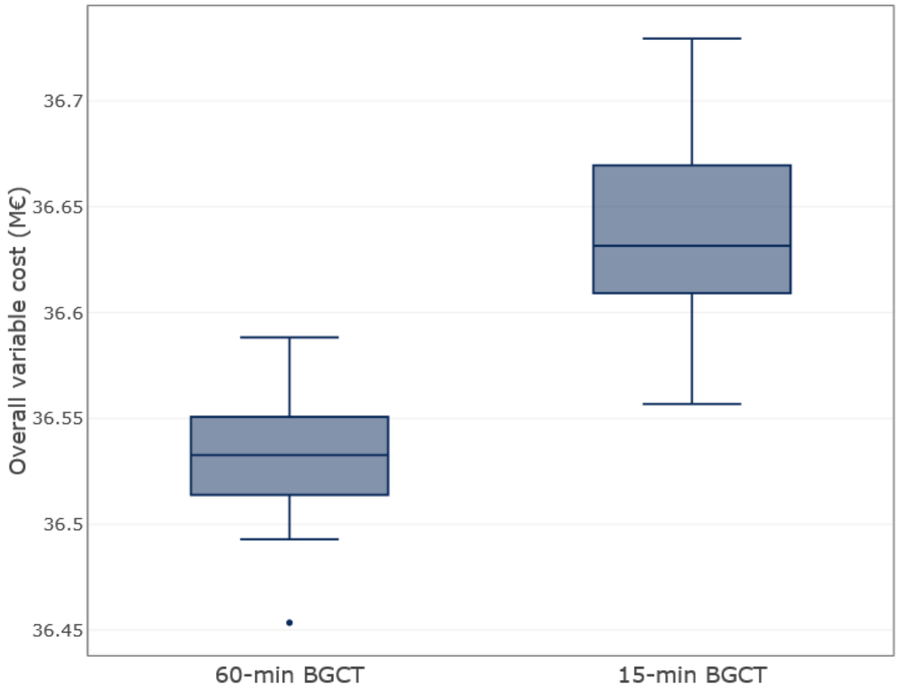

Figure 2. Overall variable cost (M€) in scenario A for the case 60-min BGCT and 15-min BGCT.

The difference in cost between "60-min BGCT" and "15-min BGCT" results from a different use of generation units to serve the demand, especially during the balancing period (one to two hour before the real-time). The detailed analysis of the units' dispatch shows that, in average, there is one supplementary start-up of OCTG in the case "15-min BGCT" compared to the case "60-min BGCT".

The difference between day-ahead or intraday energy prices and balancing activation costs provides a relevant insight to estimate to which extend market participants have good anticipations of real-time equilibrium. A tighter delta allows a better coordination by the market. Results presented in Table IX confirm that this difference is reduced, hence a better coordination, with the case "60-min BGCT".

Table IX. Difference (mean value and standard deviation) between balancing activation costs (BAC_+ for upward activations and BAC_- for downward activations) and intraday or day-ahead energy prices, in scenario A, in €/MWh.

		60-min BGCT	**15-min BGCT**
ID price - BAC_+	*mean*	0,46	1,02
	st. dev	16,07	16,00
ID price - BAC_-	*mean*	-2,24	-2,86
	st. dev	14,38	14,39
DA price - BAC_+	*mean*	-1,24	-1,49
	st. dev	6,17	5,85
DA price - BAC_-	*mean*	-3,15	-3,69
	st. dev	7,08	6,57

V. DISCUSSION

The results presented above show that the efficiency of short-term decisions as reflected by the overall variable cost depends on the timing for the balancing gate closure. This difference between a coordination by decentralized markets until 15-min ahead real time versus the SO taking centralized actions during the last hour appears as inconsistent with the theoretical reference case of pure and perfect competition being identical to benevolent monopoly. However, as stated above, this observation is made possible thanks to the realistic features of SiSTEM model including new information coming in every time steps and informational asymmetry between market participants and the SO.

Thus, it suggests that there is an optimal timing for the balancing gate closure (and the corresponding intraday market gate closure) which intrinsically varies depending on the generation mix and flexibility requirements. Due to simulation time issues, we could not empirically estimate this optimal timing based on simulations. However, some elements on the definition of the optimal timing are provided in this section.

As previously mentioned, operational decisions based on individual forecasts and on energy prices are more likely to be inefficient than operation decisions based on physical imbalance forecasts with a full picture of system capabilities and costs, in particular for assets with start-up delays which are longer than the period between the BGCT and the delivery time (real-time). Indeed, generation units have dynamic constraints that prevent power companies or the system operator from changing the generation plan close to real-time. In particular, the steady period significantly influences the ability of power units to provide flexibility. Thus, this suggests that decentralized actions should end so that the system operator still has sufficient time to change the generation dispatch if necessary to balance the system. In that respect, the BGCT should be defined in line with the delays necessary to change the generation dispatch of relevant technologies to be used for balancing. Given the dynamic constraints of typical generation units, a BGCT 60 minutes to 90 minutes before delivery could be an adequate timing.

VI. CONCLUSION

Focusing on market design options for operational balancing management in self-dispatch electric power systems, this article investigates the most relevant timing for the balancing gate closure, when market participants' decisions on the setting of controllable assets are neutralized and this responsibility is simultaneously transferred to the system operator. This discussion is central in the development and implementation of the European electricity balancing guideline and is expected to be harmonized across Europe [EBGL, 2017]. To inform this debate, this article quantifies the effects of two different short-term market designs which only differ on the balancing gate closure time.

Our analysis is based on a multi-level optimization tool called SiSTEM with a realistic modelling of short-term power system operations (see [Mathieu et al., 2017] for a detailed description of the model). Especially, the SiSTEM model represents new information coming in (forecasting process updated every 15 min) and informational asymmetry between market participants and the SO The results allows to propose the first quantitative assessment of postponing the balancing gate closure time from one hour (case "60-min BGCT") to 15 minutes ahead of the imbalance settlement period (case "15-min BGCT"). For different environments (energy mix, power plant capabilities, outages), the results highlight that central decision making during the last hour ahead real time is consistently more economical than maintaining self-dispatch driven by competitive short-term markets closer to real time. More precisely, the overall variable cost appears to be 0.08% to 0.43% higher in the case "15-min BGCT" than in the case "60-min BGCT", depending on the considered simulation scenario. The detailed analysis of the results shows that this difference in cost is mainly due to a better coordination of the available resources by the central decision maker than by decentralized power companies.

In future works, we intend to evaluate the cross-zonal impacts of interconnecting two bidding zones with different BGCT. We believe this assessment will be useful to evaluate whether BGCT should be fully harmonized among interconnected countries.

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Annex A: Details on the outages' series used in the simulations

We suppose that only nuclear (type B), CCGT (types A and B), coal and lignite face outages. The outage's parameters used in the simulations are detailed in Table X.

Table X. Outage's parameters depending on the technology.

	Yearly probability of outage	Duration of outage (h)	Out of service capacity (%)
Nuclear B	0.05	7	25
CCGT A	0.05	3	50
CCGT B	0.05	3	100
Coal	0.075	7	35
Lignite	0.075	7	35

A.1 Outages' series used for the simulations with the generation mix "Nuclear+RES+Gas"

Table XI. Outages with the generation mix "Nuclear+RES+Gas"

	Nuclear	CCGT	Coal
Number of outages – S1 winter period	10	27	4
Number of outages – S1 summer period	12	25	7
Number of outages – S2 winter period	10	28	4

Table XII. Details on outages' scenario S1 – winter period

Unit	Power company	Number of outages	Out of service capacity (MW)	Date of outages (MM/DD hh:mm)
Nuclear B unit 1	A	4	225	01/07 17:00 01/08 07:45 01/12 02:00 01/17 04:00
Nuclear B unit 2	A	6	225	01/05 11:15 01/09 07:15 01/17 12:00 01/21 06:45 02/01 05:00 02/03 11:15
CCGT A unit 1	B	6	200	01/07 07:00 01/09 16:15 01/10 09:45 01/13 12:30 01/23 07:15 01/28 12:15
CCGT B unit 1	A	14	200	01/03 23:00 01/04 04:00 01/04 17:45 01/05 20:00 01/07 10:15 01/12 20:45 01/18 21:45 01/19 08:15 01/19 18:00 01/23 03:00 01/23 13:45 01/26 13:00 01/31 10:45 02/01 22:30
CCGT B unit 2	B	7	200	01/04 13:00 01/06 12:45 01/10 06:15 01/11 09:15 01/18 14:00 01/19 14:15 01/20 17:45
Coal	B	4	150	01/06 21:00 01/19 21:30 01/20 07:45 01/31 21:15

Table XIII. Details on outages' scenario S1 – summer period

Unit	Power company	Number of outages	Out of service capacity (MW)	Date of outages (MM/DD hh:mm)
Nuclear B unit 1	A	4	225	06/01 22h00 06/06 12h30 06/25 17h00 06/27 22h15
Nuclear B unit 2	A	8	225	06/02 21h15 06/05 10h30 06/07 10h30 06/16 21h00 06/22 04h00 06/23 00h15 06/29 17h00 07/01 10h00
CCGT A unit 1	B	8	200	06/09 09h30 06/12 13h00 06/12 21h00 06/20 23h15 06/21 16h30 06/22 11h00 06/28 23h15 07/02 00h30
CCGT B unit 1	A	9	200	06/07 18h15 06/09 04h00 06/11 11h45 06/13 08h45 06/13 14h15 06/17 13h30 06/19 14h30 06/30 01h15 07/03 21h00
CCGT B unit 2	B	8	200	06/01 09h00 06/08 05h00 06/15 15h45 06/18 05h45 06/23 12h15 06/23 16h30 06/26 16h30 06/27 00h30
Coal	B	7	150	06/11 21h00 06/15 06h30 06/17 18h15 06/18 17h00 06/20 16h00 06/24 17h45 06/30 22h00

Table XIV. Details on outages' scenario S2

Unit	Power company	Number of outages	Out of service capacity (MW)	Date of outages (MM/DD hh:mm)
Nuclear B unit 1	A	4	225	01/07 17h00 01/08 07h45 01/12 02h00 01/17 04h00
Nuclear B unit 2	A	6	225	01/05 11h15 01/09 07h15 01/17 12h00 01/21 06h45 02/01 05h00 02/03 11h15
CCGT A unit 1	B	6	200	01/07 07h00 01/09 16h15 01/10 09h45 01/13 12h30 01/23 07h15 01/28 12h15
CCGT B unit 1	A	15	200	01/02 23h00 01/03 23h00 01/04 04h00 01/04 17h45 01/05 20h00 01/07 10h15 01/12 20h45 01/18 21h45 01/19 08h15 01/19 18h00 01/23 03h00 01/23 13h45 01/26 13h00 01/31 10h45 02/01 22h30
CCGT B unit 2	B	7	200	01/04 13h00 01/06 12h45 01/10 06h15 01/11 09h15 01/18 14h00 01/19 14h15 01/20 17h45
Coal	B	4	150	01/06 21h00 01/19 21h30 01/20 07h45 01/31 21h15

A.2 Outages' series used for the simulations with the generation mix "RES+Coal+Gas"

Table XV. Outages with the generation mix "RES+Coal+Gas"

	Nuclear	CCGT A	CCGT B	Coal	Lignite
Number of outages	4	19	12	15	12

Table XVI. Details on outages' scenario S3

Unit	Power company	Number of outages	Out of service capacity (MW)	Date of outages (MM/DD hh:mm)
Nuclear A unit 1	B	4	225	01/07 17:00 01/08 07:45 01/12 02:00 01/17 04:00
CCGT A unit 1	A	8	200	01/03 16:30 01/05 05:45 01/13 08:30 01/20 18:30 01/28 14:15 01/30 04:00 02/03 07:00 02/03 11:15
CCGT A unit 2	B	11	200	01/06 14:45 01/09 00:15 01/10 14:30 01/19 10:00 01/19 19:15 01/22 09:30 01/22 19:30 01/23 13:15 01/28 18:45 01/28 23:00 01/29 13:45
CCGT B unit 1	A	6	100	01/15 15:15 01/21 21:30 01/23 07:00 01/24 15:15 01/25 04:15 02/01 07:15
CCGT B unit 2	B	6	100	01/05 21:15 01/08 18:15 01/11 07:15 01/13 21:45 01/14 16:00 01/24 20:30
Coal unit 1	A	5	210	01/03 19:45 01/04 19:15 01/11 12:45

				01/18 00:30 01/31 06:45
Coal unit 2	A	3	210	01/03 04:00 01/19 02:45 01/22 01:00
Coal unit 3	B	7	210	01/04 12:00 01/12 16:30 01/16 17:15 01/20 05:00 01/25 16:00 01/28 04:15 02/02 22:30
Lignite unit 1	A	7	175	01/05 11:15 01/09 07:15 01/17 12:00 01/21 06:45 01/27 17:00 02/01 11:45 02/03 18:00
Lignite unit 2	B	5	175	01/09 18:45 01/10 19:15 01/15 03:45 01/26 11:00 01/26 21:15