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# Impact of gate closure time on the efficiency of power systems balancing

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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' 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. Based on a multi-level simulation tool with a realistic modelling of short-term power system operations, this paper proposes the first quantitative assessment of postponing the balancing gate closure time from 1 h to 15 min 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 1 h to 15 min 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.

## 1. Introduction

Electric power systems evolve to provide a major share of generation from intermittent resources where uncertainties on system equilibria require careful management owing to widespread controllable units with a variety of capabilities. In this context, as described in (Bunn and Kermer, 2018) for example, the cost efficiency of the power system will be highly dependent on operational decision making with respect to short-term flexibilities. Operational schemes are generally determined by the regulatory framework within 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 which conform to local specificities, but to mandate a strong coordination of the operational schemes used by local System Operators (SO) to activate balancing services (i.e. request a greater or lesser injection of electricity 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 must fix their injection setting, propose balancing services and let the SO take centralised decisions on their activations. Today, the BCGT varies across European countries: for example, it is set to 15 min In Germany, Belgium and The Netherlands, versus 60 min 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 min before the beginning of an imbalance settlement period (ISP), or (ii) proactive balancing management, with the BGCT set 60 min before the ISP. The opportunity to select a single value for Europe has led to intense debate dominated by theoretical views (e.g. (EFET balancing dream 2017)) on the ability of energy markets to induce efficient operational decisions. Unfortunately, no party has yet proposed a quantitative assessment of the two options (CRE, 2016). Advocates of reactive and proactive balancing management usually refer to the following dimensions to justify their preferences:

i) **Impact of proactive activations on the liquidity of the intraday market**: advocates of reactive TSOs consider that postponing the BGCT allows market participants to account for the latest information and continue trading close to real time. This additional trading opportunity fosters liquidity in continuous intraday markets, with potential benefits in terms of intraday price formation.
ii) **Impact of proactive activations on the cost of activating balancing services and reserves**: advocates of proactive balancing management consider that TSOs can rely on more resources (i.e. those who need to be triggered more than 30 min before delivery) to face similar imbalances. Under the assumption of an efficient

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balancing management, this opens the door for benefits in terms of reserve and activation expenses (CRE, 2016).

iii) **Level of transparency towards market parties in self-dispatch**: advocates of proactive balancing management highlight the fact that the market must rely on limited information to make dispatch decisions. In the particular instance of balancing, they recall that the status and capability of each asset is private information. On the other hand, energy prices (with a 15-min or 30-min granularity) potentially complemented with alerts in case of forecast scarcity of balancing reserves, would provide insufficient information for market participants to make efficient decisions (CRE, 2016).

Unfortunately, no party has yet been able to propose a quantitative assessment of the two options, and the debates remain qualitative with no factual comparison of the two approaches in the same context. To address this issue, and to 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 using 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 for analysis of 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 attention 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 each of the system-wide variable costs of serving demand with a system managed in a proactive or reactive 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 organised 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.

## 2. Background: balancing management in self-dispatch power systems

Balancing management is inherent to self-dispatch[1] 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 most of the European Member States, e.g. France, Germany, Belgium and the Great Britain. A panorama of actual practices in Europe is provided in (ENTSO-E WGAS, 2016). Based on these practices (Haberg and Doorman, 2016), propose a classification of balancing market designs: their quantitative analysis confirms that some European countries are characterized by a reactive balancing market design (Belgium, Austria, Germany, The Netherlands) whereas others are more proactive (France, United Kingdom, Nordic countries).

To ensure system equilibrium (or limit the recourse to ancillary services[2]) 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. Fig. 1 presents the timeline of these short-term operations: when the intraday markets are closed, the balancing window for the SO's actions begins and typically lasts 15 min ("short-window"), 15–60 min ("medium window") or more than 60 min ("long window"). As defined in (EU 2017/1485), resources used to balance the system can be classified into three types of reserve. Frequency containment reserve corresponds to a fast and automatic response to stop frequency variations. Frequency restoration reserve provides energy services to restore the frequency to its nominal value (50 Hz in Europe). Replacement reserve allows for the release of assets participating in the previous steps in order to ensure their availability in case of future imbalances.

We detail hereafter how schedules are updated ahead of 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 to 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 their 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.

### 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. However, 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 the system balance by activating balancing services. This service may rely on a variety of products (mainly standard ones).

[1] As defined in (EU 2017/2195), 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". The self-dispatch system is used in most European countries. However, Italy, Ireland, Poland and Greece are organised with central dispatch for the different decision-making horizons, including balancing (ENTSO-E WGAS, 2016, see page 6).

[2] 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.

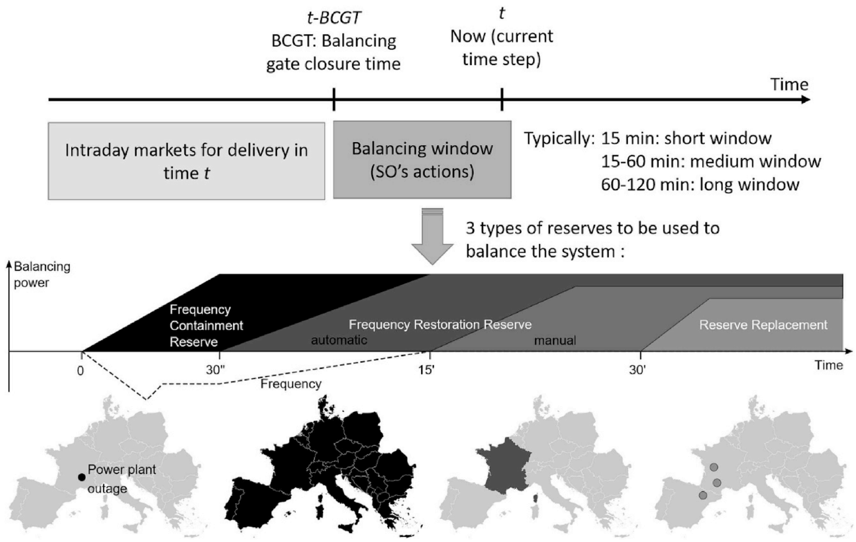


**Fig. 1.** Timeline of short-term operations.

## 3. Methodology: 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 the SO of its generation schedule, and finally proposes balancing services. After the balancing gate closure, the SO activates balancing energy to restore the power balance to the system using all balancing service offers proposed by market participants, including balancing reserves. The model focuses on frequency restoration reserves and replacement reserves, whereas frequency containment reserves are out of the scope (see Fig. 1). 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 the 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 there is perfect information and no transaction costs, decentralized markets provide the same result as a benevolent monopoly, i.e. the SO. However, in practice, some of these hypotheses do not hold and 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 unit 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.

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 min) 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. However, 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 energy generation minus demand forecasts by market participants tends to be a more accurate view of system balance than estimation by the SO). However, collecting all balancing bids offers the SO full visibility on the flexibility in the system, whereas each market participant only knows its own flexibility, but has no visibility on the actual flexibility of its competitors (it only knows the intraday price for energy).

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

In the model, power companies maximise their revenues while serving their energy consumption portfolio thanks to energy produced internally (if they own generation assets) or energy bought on day-head or intraday markets. To do so, 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 realisations by overlaying a uniform noise and smoothing the resulting signal. For the sake of simplicity, power companies offer energy products (in day-ahead, intraday and balancing markets) based on generation schedules and their actual generation costs.

#### 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-min granularity integrating the constraints of thermal generation units, hydro-electric reservoirs and curtailable renewable generation (typically wind power and PV). 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. Hydroelectric 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 constraints into the short-term management of the water. The value of the stock is linearly dependent on the stock level. Renewable sources (typically wind power and PV) are considered as curtailable generation units with 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 as it would be too computationally demanding and time-consuming for operators. 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 min to precisely study the impact of balancing. Long-term scheduling allows for the integration of day-ahead market exchanges and aims at estimating how to satisfy the demand at lowest cost. Short-term scheduling modifies the scheduled generation planning of assets over the next 2 h 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. Scheduled generation planning of a power company's asset may vary until the BGCT. Beyond this, the generation schedule is considered as fixed and can only be modified when the SO activates balancing offers.

In order to participate in 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 what extent the power company can modify its portfolio's injection and at what cost. This information is communicated through explicit offers to the market. An offer is defined, as a minimum, as an energy volume over a given period with 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 to be linked to other offers. The offer-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 maximising or market minimising the energy generated. 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 costs 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. This strategy enables the offering of more energy products owing to the complementarity between generation assets, but it is more challenging to model than unit-based offers. Portfolio-based offers are generated based on a predefined number of generation scenarios as follows. By default, 20 scenarios[3] are considered. First, three unit commitments are performed with three different targets: minimum generation, maximum generation and getting as close as possible to the scheduled generation planning. Then, seventeen intermediate scenarios are generated in between these three scenarios. Unit 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 the basis on which to define the flexible offers and is arbitrarily set to the load forecast. 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 the total cost between the two scenarios divided by the difference of volume over the whole horizon. The process is repeated for the next scenario, taking the energy difference with the previous one. 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 those 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 midday and results are provided 30 min later. In SiSTEM, the clearing of the day-ahead market is formulated as mixed-integer linear program aiming at maximising 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 at every simulation time step, i.e. every 15min. The clearing is solved using the same formulation of the DA optimization clearing problem. These procedures provide a price at each intraday market clearing for each opened intraday market period. An indicative intraday price is built for a given delivery time step by taking the weighted average over the volumes exchanged in each intraday auction. 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 ensure that sufficient balancing services will be proposed by market parties, and therefore contracts balancing reserves. In this study, the volume of reserve that each market party must provide is defined as an input of the simulation tool that does not vary between the investigated scenarios (and thus, the reservation cost is not included in the cost analysis of the results). 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

[3] The default number of scenarios was chosen to be sufficiently high to provide relevant energy offers while keeping a reasonable computing time.

future imbalances, the SO activates available balancing services, partially or totally, while respecting notice delays of generation units. The forecasted imbalances are assumed to be equal to the average of the five last recorded values, and do not depend on the more-detailed forecasts made by the various power companies. The SO restores balance while minimising balancing energy cost, taking into account technical constraints and uncertainties on future system imbalances. The cheapest offers are 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 its impact on the future. More details on the optimization problem guiding the actions of the is provided 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 the schedule of all its significant units to the SO, resulting from the latest unit commitment and exchanges. The imbalance of a power company is given by the difference between its realized generation output and its last generation schedule declared to the SO. 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 for 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).

### *3.5. Use of SiSTEM to assess proactive and reactive balancing regime*

To assess the technical and economic impact of shifting the BGCT in a self-dispatch power system and using SiSTEM, we have simulated the short-term operation of a virtual power system capturing the complexity of a real-world power system. To limit the computational burden, we have considered systems with a limited number of assets, 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-min granularity.

We considered, as the 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 of hydroelectric assets. 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.[4] The assessment presented in Section 4.3 corresponds to the average from the 30 runs.

## 4. Case studies and data

The case study is designed to be as close as possible to the actual functioning of power systems. However, the detailed cost and technical parameters of generation units are based on literature reviews, so should not be considered as representative of a specific, actual 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.

### *4.1. Load demand*

We consider two types of net demand curves based on French historical data.[5] To obtain the net demand curves, generation from fatal units (cogeneration and run-of-river hydroelectric plants) are subtracted from the demand curves.

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

### *4.2. Generation constraints*

The SiSTEM model allows one to represent the functioning of generation units in detail. Generation technologies are modelled with the features presented in Table 1 for nuclear and thermal technologies and in Table 2 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.

Each parameter was scaled to represent a standard real-life unit, except for the minimum power that was decreased, importantly, to take into account the aggregation of various real-life units. As a consequence, start-up costs were scaled accordingly with minimum power.

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

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 min for CCGT (A or B types) and to 5 min for OCGT. In this context, the SO can activate balancing services from OCGT within 15 min whereas CCGT cannot provide it within this time period.

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

### *4.3. Generation mix and power company portfolios*

We have considered two different generation mixes characterized by the parameters presented in Table 3. The assets are owned by four different power companies, as detailed in Tables 4 and 5. 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 entire renewable production but no consumers. Regarding the definition of the day-ahead market offers, power company A uses a portfolio-based calculation, whereas other companies use unit-based calculations. For all other markets (intraday, balancing), the offer definitions are unit-based.

[4] 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%.

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

**Table 1**
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 |

**Table 2**
Parameters of hydropower units.

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

N.B.
[a] The water value is used for dispatch decisions.
[b] 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.

**Table 3**
Parameters of the generation mix and reserves.

| Mix name | "Nuclear + RES + Gas" | "RES + Coal + Gas" |
|---|---|---|
| **Total installed capacity** | **5.82** | **8.58** |
| 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 |
| **Upward reserve: total (GW)** | **0.15** | **0.30** |
| Gas capacity (GW) | 0.10 | **0.15** |
| Hydro capacity (GW) | 0.05 | 0.00 |
| Coal capacity (GW) | 0.00 | 0.15 |
| **Downward reserve: total (GW)** | **0.10** | **0.20** |
| Nuclear (GW) | 0.10 | 0.00 |
| Gas capacity (GW) | 0.00 | 0.20 |

**Table 4**
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 5**
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 |

**Table 6**
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 |

### 4.4. Summary of the scenarios

The five scenarios under consideration are characterized in Table 6. These various scenarios allow one to cover a wide range of situations and to estimate the robustness of the results.

## 5. Results and discussion

From a 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

**Table 7**
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 |

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 value of lost load (3000 €/MWh).

As detailed in Table 7, the 60-min BGCT has the lowest overall variable cost of 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 one of the 60-min BGGT. The inefficiency rate of the 15-min BGCT, presented in Table 7, varies from 0.08% to 0.43% in the five considered scenarios.

The differences in overall variable cost observed between a 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. approximately €70 billion/year to serve 3500 TWh in Europe), a loss of efficiency of 0.3% would correspond to €210 million/year on the European scale.

The difference in overall variable cost between 15-min BGCT and 60-min BGCT (0.1%–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 through the relative inefficiency of decentralized decisions, based on an incomplete view of the system state during the final hour ahead of real time.

Further investigation has demonstrated that the accuracy of the forecast of SOs vs. individual forecasts by power companies cannot explain such a difference. Indeed, as depicted in Table 8, 60 min before the ISP, SOs tend to have less-accurate predictions than the sum of predictions by the power companies.

The greater efficiency of centralised decision-making, between 60-min and 15-min ahead of the ISP, relates in practice to the lack of coordination between competitors who face uncertainty of their own commitments and do not have any visibility on the flexibility of other market participants. In our simulations, this materialises 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 min and below 60 min. This is illustrated in Fig. 2, which depicts both the balancing activations made by the SO and the changes made by power companies during the final 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 “60-min BGCT” case as the SO faces a higher imbalance (see Table 8). However, by depicting schedule changes decided by power companies between t-60 min and t-15 min in the “15-min BGCT” case (see the light blue area in Fig. 2), the Figure shows that actions taken during the final hour are significantly more numerous in volume in the “15-min BGCT” case than in the “60-min BGCT” case.

Finally, we note that a 60-min BGCT generally leads to a greater number of balancing energy activations by the SO, which leads potentially to higher “balancing energy costs”, as identified by ACER in (ACER/CEER, 2017). However, a 15-min BGCT involves many decentralized decisions likely to significantly increase the energy procurement cost in a “reactive” balancing management scheme (see light blue area in Fig. 2), which should duly be taken into account by policy makers if they intend to maximise social welfare.

**Table 8**
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 |

### 5.1. Detailed analysis (scenario A)

This section analyses the results obtained for Scenario A in detail. To keep our analysis concise and informative, results of other scenarios are not detailed here, but, as presented above, all results follow the same trend. Scenario A corresponds to a winter month for the “Nuclear + RES + Gas” mix as described in Section 4. 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 Fig. 3. It confirms the significance and the robustness in the cost difference between the two BGCT options.

The difference in cost between “60-min BGCT” and “15-min BGCT” is from a different use of generation units to serve the demand, especially during the balancing period (one to 2 h prior to real-time). The detailed analysis of the units' dispatch shows that, on average, there is one supplementary start-up of an OCTG in the “15-min BGCT” case compared to the “60-min BGCT” case.

The difference between day-ahead or intraday energy prices and balancing activation costs provides a relevant insight into how to estimate to what extent market participants have a good anticipation of real-time equilibria. A tighter delta allows a better coordination by the market. Results presented in Table 9 confirm that this difference is reduced, hence a better coordination with the case “60-min BGCT”.

### 5.2. 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. 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. Owing 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 compared to operational 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 of 60 min–90 min prior to delivery could be an adequate timing.

## 6. Conclusions and policy implications

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

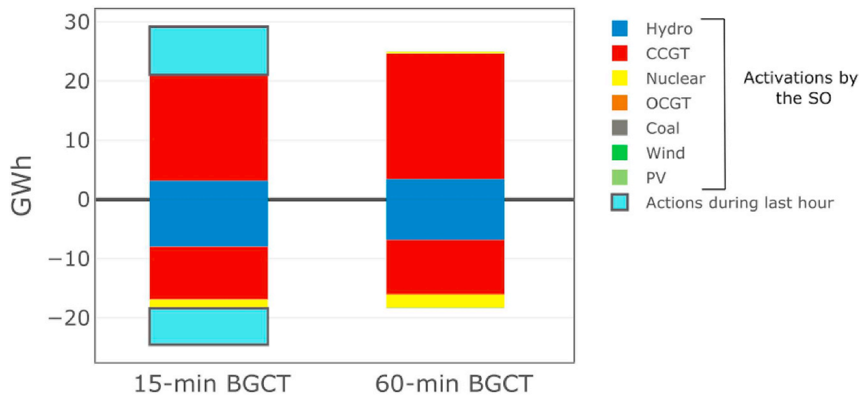


**Fig. 2.** Details on the changes and balancing activations (total over the simulated period – in GWh) during the last hour, in scenario A.

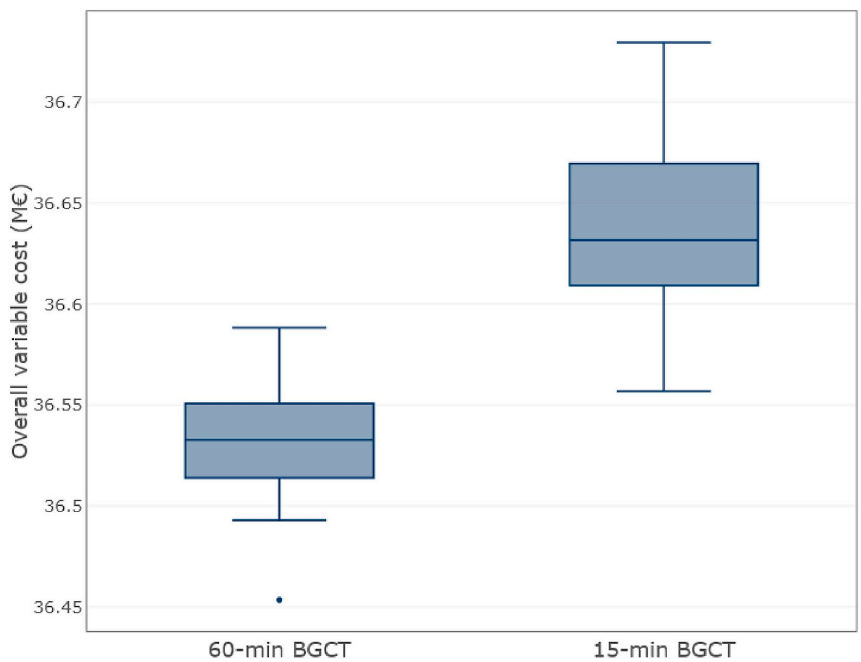


**Fig. 3.** Overall variable cost (M€) in scenario A for the case 60-min BGCT and 15-min BGCT.

**Table 9**
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 |

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 made European standard (EBGL, 2017). Advocates of the different balancing options generally draw on qualitative assertions (EFET balancing dream 2017; CRE 2016) regarding (i) impact on the liquidity of the intraday market, (ii) impacts on the cost of activating balancing services and reserves and (iii) level of transparency. 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). The results allow for proposing the first quantitative assessment of postponing the balancing gate closure time from 1 h ("60-min BGCT" case) to 15 min ahead of the imbalance settlement period ("15-min BGCT" case). For different environments (energy mix, power plant capabilities, outages), the results highlight that central decision making during the final hour ahead of 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%–0.43% higher in the "15-min BGCT" case than in the "60-min BGCT" case, 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 BGCTs. We believe this assessment will be useful to evaluate whether BGCTs should be fully harmonized among interconnected countries.

## Disclaimer

The views and opinions expressed in this paper are those of the authors and do not necessarily reflect those of the partners of the CEEM, nor the official position of EDF (Électricité de France).


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## Appendix 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 10.

Table 10
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 11
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 12
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 |

(*continued on next page*)

Table 12 (*continued*)

| Unit | Power company | Number of outages | Out of service capacity (MW) | Date of outages (MM/DD hh:mm) |
|---|---|---|---|---|
| | | | | 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 13
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 14
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 | |

(*continued on next page*)

Table 14 (*continued*)

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

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

Table 15
Outages with the generation mix "RES + Coal + Gas".

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

Table 16
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<br>01/08 07:45<br>01/12 02:00<br>01/17 04:00 |
| CCGT A unit 1 | A | 8 | 200 | 01/03 16:30<br>01/05 05:45<br>01/13 08:30<br>01/20 18:30<br>01/28 14:15<br>01/30 04:00<br>02/03 07:00<br>02/03 11:15 |
| CCGT A unit 2 | B | 11 | 200 | 01/06 14:45<br>01/09 00:15<br>01/10 14:30<br>01/19 10:00<br>01/19 19:15<br>01/22 09:30 |

(*continued on next page*)

Table 16 (*continued*)

| Unit | Power company | Number of outages | Out of service capacity (MW) | Date of outages (MM/DD hh:mm) |
|---|---|---|---|---|
| | | | | 01/22 19:30<br>01/23 13:15<br>01/28 18:45<br>01/28 23:00<br>01/29 13:45 |
| CCGT B unit 1 | A | 6 | 100 | 01/15 15:15<br>01/21 21:30<br>01/23 07:00<br>01/24 15:15<br>01/25 04:15<br>02/01 07:15 |
| CCGT B unit 2 | B | 6 | 100 | 01/05 21:15<br>01/08 18:15<br>01/11 07:15<br>01/13 21:45<br>01/14 16:00<br>01/24 20:30 |
| Coal unit 1 | A | 5 | 210 | 01/03 19:45<br>01/04 19:15<br>01/11 12:45<br>01/18 00:30<br>01/31 06:45 |
| Coal unit 2 | A | 3 | 210 | 01/03 04:00<br>01/19 02:45<br>01/22 01:00 |
| Coal unit 3 | B | 7 | 210 | 01/04 12:00<br>01/12 16:30<br>01/16 17:15<br>01/20 05:00<br>01/25 16:00<br>01/28 04:15<br>02/02 22:30 |
| Lignite unit 1 | A | 7 | 175 | 01/05 11:15<br>01/09 07:15<br>01/17 12:00<br>01/21 06:45<br>01/27 17:00<br>02/01 11:45<br>02/03 18:00 |
| Lignite unit 2 | B | 5 | 175 | 01/09 18:45<br>01/10 19:15<br>01/15 03:45<br>01/26 11:00<br>01/26 21:15 |

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