Study report on Scarcity Pricing in the context of the 2018 discretionary incentives

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Executive Summary

This study report, drafted by Elia in the context of the 2018 discretionary incentives defined by CREG, deals with the modelling of scarcity pricing. This study is a new learning step and builds further on earlier work done by CREG in collaboration with UCL CORE. The current study entails no commitment or intention by Elia to actually develop or promote at this stage the concrete implementation of a scarcity mechanism.

This study has been realized in close cooperation with CREG and UCL CORE. Not only are at the core of this study the scarcity price model and surrounding assumptions as defined by CREG and UCL CORE, also the intermediate and final study results have been discussed with them and their feedback has been integrated in this report.

The contribution of this study is threefold:

(1) the translation or mapping of the currently studied scarcity pricing model, i.e. the model used by UCL CORE and inspired on the Texan ERCOT model, to the Belgian context in its best possible way,
(2) the definition of a concrete Belgian dataset suitable for the purpose of this model and
(3) the simulation of the model resulting in scarcity price adders and settlement calculation for the entire year of 2017. These contributions meet the objectives identified at the start of the study.

The study reveals that applying the considered scarcity pricing model requires strong assumptions in terms of mapping it to the Belgian market designs. It raises questions on how this could be done in practice without giving in on the objective of the model in terms of creating an investment signal, while at the same time ensuring full compatibility with the current and foreseen Belgian and European market design.

Given the assumptions made on fine-tuning of the model and the data calibration applied, the scarcity price model results for 2017 generally in low price adders with a very limited effect on settlement. It may require further research to assess whether the model should undergo changes and/or whether 2017 should really be considered as a mild year in context of such scarcity pricing model.

Nevertheless, it is illustrated in the study that the dynamic of the model for determining price adders works, i.e. scarcity price adders increase when the remaining margin of available reserve in the system decreases and thereby the loss of load probability increases. It is also illustrated that high system imbalances alone are not a sufficient (and in principle not even a necessary) condition to trigger high scarcity price adders.

1 Introduction

This introduction covers three aspects. First the context of this study report is described. Next, the concept of scarcity pricing itself is discussed and put into perspective according to Elia's point of view. Finally, the outline of the remainder of this report is provided.

1.1 About this study

This study is performed by Elia in the context of the discretionary incentives identified by CREG for Elia for 2018, cf. CREG's decision (B)658E/45 of 29 June 2017[1]. The scope of the discretionary incentive covers mainly two aspects building further on the earlier results of a study done by CREG on scarcity pricing: (1) setting up a mechanism for evaluating the available volume of reserves in real-time in such a way that it can be used in the studied scarcity model in view of a potential implementation and (2) applying this mechanism on a quarter hourly basis on a historical period. The results of these works also have to be published.

One should consider this study in the context of the ongoing effort of CREG in studying the concept of scarcity pricing as a potential mechanism that one day could be applied to the Belgian market, although without a concretely defined timing or roadmap. This study is as such a learning step and an analysis of the concept based on historical data. The objective is to have some conclusions about lessons learned to improve the scarcity pricing model itself and reflect on how it could be applied in Belgium. In this context, Elia refers to the decision of the CREG 658E/52 of 28 June 2019[2] about the discretionary incentives identified by CREG for Elia for 2019, in which a new incentive related to scarcity pricing has been integrated, as a next step in this process. The current study entails no commitment or intention by Elia to actually develop or promote at this stage the concrete implementation of a scarcity price mechanism

In order to meet the requirements defined by this discretionary incentive, Elia has engaged into an open and collaborative discussion with CREG. The academic research group UCL CORE, represented by Prof. Yves Smeers and Prof. Anthony Papavasiliou, has also been closely involved by CREG. These discussions have led to a further common interpretation and fine-tuning of the objectives and requirements of the incentive. It was agreed that it would be most useful if Elia – in the context of this incentive for 2018 – could provide a detailed suggestion on which concrete data available for the Belgian system and market could be used as an input for the scarcity pricing model. Also, it was agreed that Elia would not only provide the (large amount of) data to CREG and UCL CORE, but that it would also conduct itself all necessary calculations related to

[1] https://www.creg.be/fr/publications/decision-b658e45
[2] https://www.creg.be/nl/publicaties/beslissing-b658e52

the scarcity pricing model, i.e. an offline implementation of the model relying on historical data. Finally, it was agreed that Elia would run the model on a complete 2017 dataset, rather than the initially foreseen 8 first months of 2018, as this would provide a stable set of data (e.g. in terms of reserve products) and would facilitate a timely discussion of the dataset, the model and its outcomes.

Given the work already done by CREG together with UCL CORE on this topic (cf. section 2.1) and the purpose of building further on these efforts, the scarcity pricing model to be used throughout this study has been provided by CREG and UCL CORE to Elia. Also, all more detailed choices and the proposed mapping of the concept to the Belgian scene follow the guidance provided by CREG and UCL CORE. Nevertheless, Elia has provided at regular occasions its feedback and point of view on the choices to be made during this exercise.

The main deliverables of the incentive after this extensive alignment are thus twofold:

- The delivery of a complete dataset to CREG (and UCL CORE) allowing the calibration of the model and applying it to 2017. After a first sample delivered on 7 September 2018, the full dataset has been delivered on 5 November 2018.
- The delivery of this report to CREG (and UCL CORE) and a publication of a non-confidential version on the website elia.be. The results and conclusions presented in this report have been developed throughout the study period and have been progressively discussed and fine-tuned upon feedback and interaction with CREG and UCL CORE.

Finally, Elia appreciated the open and constructive debate that took place with CREG and UCL CORE in the context of this incentive. In particular, the numerous exchanges with Prof. A. Papavasiliou have greatly contributed to the realization of this work and the quality of the output.

1.2 About the concept of scarcity pricing

The concept of scarcity pricing is as such not new and has not only been studied by academics, but has also been implemented in several markets. Although a single way to conceive a scarcity pricing model does not exist, the model developed by Prof. William Hogan, that is also implemented and is up and running in the Texas energy market (ERCOT), is probably the most cited and best known scarcity pricing model. In any case, this model has formed the base model for this study since it has been used by UCL CORE and CREG in their previous works on this topic.

It is Elia’s understanding that the main objective of scarcity pricing is to set up a less volatile revenue stream towards capacity available in the system for ensuring its adequacy compared to a pure energy-only market. In the latter market concept, investors rely on rare (and thereby volatile) price spikes for the recovery of their investment costs. Those spikes are supposed to occur when the system is confronted with actual scarcity. In a scarcity pricing model the goal is to create extra revenues whenever the system is approaching a scarcity situation, without requiring that actual scarcity has to take place.

As these situations are likely to occur on a more frequent basis (which also depends on the actual setup of the model) the revenue streams towards investors become less volatile, which should contribute to an improved investment climate.

It is Elia's point of view that such system could indeed create an extra revenue stream and may contribute to a more stable revenue stream. In this respect it may help in alleviating so-called missing money concerns. However, to our knowledge, there is no guarantee – neither theoretical nor in practice – that such scarcity pricing model alleviates all missing money concerns that are voiced in the context of the current energy(-only) market and would therefore be an overall and robust solution for ensuring adequacy on the longer run.

When studying the potential implementation of Hogan's model on the Belgian market, a number of considerations are important:

- The Belgian market design, governed largely by European legislation, differs significantly from many U.S. markets and from the Texan ERCOT market in particular. The most crucial difference is that the Belgian market does not follow a central dispatch logic, but market parties take their own dispatch decisions. Also the organization of the market in day ahead, intraday and balancing time frames are fundamentally different. This at least triggers several questions to be solved when going for a Belgian implementation of this model.
  As described in more detail in section 2.3, the mapping of the applied model to the Belgian system requires very strong hypotheses on market design, which are however required in order to ensure that not only dispatched capacity but also available (but not dispatched) capacity can benefit from the scarcity price adders. Especially for this latter aspect there is little to build on in the current Belgian market design.
  The Texas market model and scarcity pricing implementation also facilitates in an easier way the financing of the mechanism. Although part of such mechanism could by financed like existing market mechanisms (e.g. like the functioning of imbalance tariffs that penalize and reward different parties and thereby foresee in its own financing system), other parts (e.g. the part of the remuneration foreseen for available reserves) would require a financing source.
- The Belgian market is strongly coupled to neighboring markets. Not only are day-ahead and intraday markets already coupled, also real-time balancing markets should be coupled by 2021 or 2022. This at least triggers the question on how a scarcity price model could be implemented in Belgium in such a way that it is both compatible with the overall target design in Europe across all time frames and not distorting markets and incentives for Belgian and/or foreign market parties.
  In this respect – and notwithstanding any other advantages the scarcity pricing model may have - it may be useful to consider awaiting the implementation of the Electricity Balancing Guideline. The balancing market is at the eve of undergoing significant developments that may complicate the application of the scarcity pricing model. For instance, aspects related to imbalance settlement harmonization will have to be developed. It may be useful to wait until this has

been completed and then judge on the applicability of such a mechanism at a Belgian or wider scale.
Also, introducing a scarcity price adder in for instance the day-ahead time frame would require very significant changes to the current way of setting the price in the coupled European energy markets and it is hard to imagine that applying it only at Belgian level would be without any effect.
This of course does not exclude any further market design evolutions that may facilitate the application of such a scarcity pricing model. It remains to be seen whether the upcoming Clean Energy Package or other future European legislation may contribute to such evolutions.

This study does not provide an answer to the above considerations, neither does it rule out the viability of a scarcity pricing model. It contributes to further reflections that could eventually help to solve some of the questions raised. Also in this respect, this study should be considered as a learning step in the context of an ongoing effort of better understanding the scarcity pricing mechanism.

1.3 Outline of the report

The remainder of this report is structured as follows:

- **Section 2** describes the scarcity pricing model used. It provides the mathematical formulas for both the calculation of the price adder(s) itself and how the settlement of the price adder(s) is modelled. It also describes how the model is mapped to the Belgian market design and which hypotheses are needed to do so.
- **Section 3** describes which 2017 data have been used to calibrate and feed the model. The dataset itself is obviously not included in this report, but – given its large size and format – has been provided directly to CREG and UCL CORE.
- **Section 4** gives the results of the calculations done using the scarcity pricing model on 2017 data. The resulting price adders themselves are discussed, as well as their settlement effects.
- **Section 5** summarizes the main conclusions from this study.

Note that this report has two versions. A version containing confidential and/or market-sensitive data is provided only to CREG and UCL CORE. A version not containing such data (either via anonymizing, aggregating or – if unavoidable – deleting some aspects) is published on the website of Elia.

2 Description of the Scarcity Price Model

2.1 Previous Research by CREG and UCL CORE

The Université Catholique de Louvain (UCL) – Center for Operations Research and Econometrics (CORE) has performed extensive research in the field of Scarcity Pricing. UCL CORE has collaborated with CREG in the analysis of a scarcity price model applied to Belgium. Over the past two years UCL CORE and CREG, as co-authors, have published two notes on the topic:

- *"Note on Scarcity Pricing applied to Belgium"*[3], CREG and UCL CORE, 12 May 2016
- *"Note on an extended analysis of capacity remuneration in scarcity conditions"*[4], CREG and UCL CORE, 30 November 2017

The model applied by UCL CORE closely follows the research from Prof. William Hogan (Harvard) on scarcity pricing. The applied model based on Prof. Hogan's research is currently implemented in the US by the Electricity Reliability Council of Texas (ERCOT).

The model presented in the remainder of this chapter is fully aligned with the model applied by UCL CORE.

[3] See https://www.creg.be/fr/publications/note-z160512-cdc-1527
[4] See https://www.creg.be/fr/publications/note-z1707

2.2 The scarcity price model

This section briefly describes the scarcity price model as proposed by UCL CORE and used in the simulations performed by Elia. A thorough description of the model is available in the CREG notes mentioned in 2.1.

2.2.1 Scarcity Price Adder calculation

The principle of the scarcity price model is that, during scarcity situations, the price of energy should be incremented by means of a price adder, while at the same time, the remuneration of available reserves should also be incremented by means of another price adder. As explained in the introduction (Section 1.2), it is expected that these potential extra remunerations in the energy and reserve markets act as an investment signal for new capacity. Note that the energy market price adder and the reserve market price adder are not necessarily the same.

In the theoretical model, the price adder to the energy and reserve price has to be linked to the scarcity level. This scarcity level is determined from a probabilistic point of view by the use of a Loss of Load Probability (LOLP) distribution. Furthermore, the price adder can be determined for different time horizons, to differentiate between scarcity on a short-time horizon (15min for instance) from scarcity on a longer-term horizon.

In this model, there are two price adders at two different time horizons, (T_1 and T_1+T_2). These price adders are based on the so-called Loss of Load Probability (at time horizons T_1 and T_1+T_2). The Loss of Load Probability can be described as the likelihood that not all of the energy demand can be covered and depends, in this model, on the remaining available reserve at different time horizons (T_1 and T_1+T_2). The goal of distinguishing between time horizons (T_1 and T_1+T_2) is to model that some reserves can be available as from T_1 while others react slower and can only be available as from T_1+T_2. This allows modeling situations in which there is no scarcity at horizon T_1+T_2 but with scarcity at horizon T_1.

In the model, the scarcity price mechanism is applied to a real-time energy market and to a real-time reserve market. Note that in the Belgian market framework, the concept of real-time energy market can be transposed to existing concepts (balancing for instance), but that the concept of real-time reserve capacity market does not find an equivalent in today's Belgian market design. In Section 2.3 the mapping of the theoretical model to the actual Belgian market framework is developed further.

In a context without scarcity price, the theoretical real-time energy price should be linked to the incremental cost of serving demand, as shown in the following equation:

$$\lambda = MC(\sum_g P_g)$$

With

λ: Real-time energy price

$\widehat{MC}(\sum_g p_g)$: Incremental cost for meeting an additional increment in demand.

In the model, the real-time energy price is incremented with two price adders as shown in the following equation:

$$\lambda = MC(\sum_g P_g) + \frac{T_1}{T_1+T_2}\left(VOLL - \widehat{MC}\left(\sum\nolimits_g p_{g,t}\right)\right) \cdot LOLP_{T_1}(R_{T_1}) + \frac{T_2}{T_1+T_2}\left(VOLL - \widehat{MC}\left(\sum\nolimits_g p_{g,t}\right)\right) \cdot LOLP_{T_1+T_2}(R_{T_1+T_2})$$

Equation 1 Real-time energy price calculation with scarcity price adder

With

λ: Real-time energy price

$\mathrm{LOLP}_{T_1}(\mathrm{R}_{T_1})$: Loss of Load Probability at T_1 minutes with R_{T_1} as available reserve.

$\mathrm{LOLP}_{T_1+T_2}(\mathrm{R}_{T_1+T_2})$: Loss of Load Probability at $T_1 + T_2$ minutes with $R_{T_1+T_2}$ as available reserve.

$\widehat{MC}(\sum_g p_{g,t})$: Incremental cost for meeting an additional increment in demand.

$R_{T_1+T_2}$: Reserve capacity that can respond within $T_1 + T_2$ minutes

R_{T_1}: Reserve capacity that can respond within T_1 minutes

VOLL: Value of Lost Load

Taking separately the T_1 adder and the T_1+T_2 adder can be defined according to the following equations:

$$adder_{T_1} = \frac{T_1}{T_1+T_2}\left(VOLL - \widehat{MC}\left(\sum\nolimits_g p_{g,t}\right)\right) \cdot LOLP_{T_1}(R_{T_1})$$

Equation 2 Fast reserve price adder

$$adder_{T_1+T_2} = \frac{T_2}{T_1+T_2}\left(VOLL - \widehat{MC}\left(\sum\nolimits_g p_{g,t}\right)\right) \cdot LOLP_{T_1+T_2}\left(R_{T_1+T_2}\right)$$

Equation 3 Slow reserve price adder

The real-time energy price formula in Equation 1 can be rewritten as:

$$\lambda = MC(\sum_g P_q) + adder_{T_1} + adder_{T_1+T_2}$$

Equation 4 Real-time energy price calculation based on adders at two different time horizons

Equation 4 shows that the total increment to the real-time energy price, from the incremental cost, is the sum of the slow reserve and fast reserve adders. This comes from the way the settlement of reserves is foreseen in the model (see 2.2.2), where reserves are remunerated depending on the time horizon of scarcity they help with.

Stated otherwise, each of the price adders is calculated as the product of, on the one hand, the Loss of Load Probability at the specific price adder horizon taking into account the available reserve at the price adder horizon and on the other hand the VOLL minus the incremental cost for supplying demand. The price adder is expected to increase during scarcity situations, determined by the LOLP. An increase in the LOLP will yield an increase in the adder. From Equation 1, given the VOLL is estimated at thousands of €/MWh (Section 2.3.1), if the LOLP reaches a significant value, e.g. 50%, the real-time energy price could be affected significantly.

Note that Equation 1 provides particularly the real-time energy price incremented with the scarcity price adders. In the real-time reserve capacity market, the price adder depends on the time horizon at which reserves can react. The model foresees that reserves should be settled with a price in accordance with the scarcity time horizon they play in. This is developed further in the next section.

2.2.2 Settlement calculation

This section explains the settlement approach used in the model. The model distinguishes different markets, i.e. energy and reserve, at different time horizons, i.e. forward and real-time. The first subsection explains the different markets in the model. The second subsection explains the specificities of the settlement approach for two different types of actors: producers and consumers.

2.2.2.1 Description of the assumed market model for settlement

According to the model, the price adder intervenes in the settlement of different parts of the (assumed) market framework. This market framework consists of four elements, each having its own price:

- *Real-time energy market:* This market represents the exchanges of energy between market participants at real-time. The price adders are applied as a supplement to the real-time energy price. Denote as λPRT_t the real-time price for energy [€/MWh] (e.g. imbalance price)

- *Real-time reserve market:* The model assumes a real-time reserve market, which remunerates reserve capacity available in real-time. Note that the model explicitly mentions that this consists of remaining reserve capacity. Activated reserve is assumed to be remunerated in the real-time energy market[5]. Note that indirectly reserve activations may be affected by the real-time reserve market, because their activation may require that reserve providers buy back the activated capacity at the real-time reserve capacity price. In this real-time reserve market, the price adder can be different depending on the time horizon at which the reserves are able to react. There can be either fast reserves reacting on T_1 and slow reserves reacting on T_1+T_2. Denote as λRRT_t the real-time price for reserve [€/MW-h] (this does currently not exist currently in Belgium);
- *Forward energy market:* This market represents the forward exchanges of energy between market participants. Denote as λPF_t the forward price for energy [€/MWh] (e.g. day-ahead price);
- *Forward reserve market:* This market represents the reserve capacity committed beforehand. For instance, reserve contracted upfront by the TSO would fall in this market category. Denote as λRF_t the forward price for reserve [€/MW-h] (e.g. day-ahead or month-ahead reserve price);

In the model the prices are determined as follows:

- The real-time price for energy λPRT_t is calculated using the formula described in Equation 1.
- The real-time price for reserve λRRT_t is calculated for two types of reserve, i.e. λRRT_t^F for fast-moving reserves (i.e. a response time of T_1) and λRRT_t^S for slow-moving reserves (i.e. a response time of T_1+T_1) respectively calculated as follows:

$$\lambda RRT_t^F = adder_{T_1} + adder_{T_2}$$

Equation 5 Fast-moving reserve real time reserve price

and

$$\lambda RRT_t^S = adder_{T_2}$$

Equation 6 Slow-moving reserve real time reserve price

- Note that following Equation 5 the fast-moving reserve real-time price is the sum of the adders at the two time horizons. This implies that fast reserve is

[5] Note that in current Belgian context, reserve activations are remunerated according to contractual terms, while in the model they are considered remunerated at clearing price in the real-time energy market.

contributing to alleviate scarcity at both time horizons.

- In the assumed model, like in the notes already published by UCL CORE and CREG, the price adder is only applicable to the real-time prices. Therefore, the forward price for energy λPF_t and the forward price for reserve λRF_t are considered unaffected by the scarcity price adders. This implies there is no explicitly ensured back-propagation of the scarcity price adder to the forward time frame.

2.2.2.2 Description of the revenues of producers and consumers with the price adder

In the general scarcity pricing model the revenues of producers and consumers (being able to provide reserves) take into account the extra components created by the scarcity price adder.

Firstly, for **producers** the total revenues are computed as follows:

- Forward market: $\lambda PF_t \cdot pF_{gt} + \lambda RF_t \cdot rF_{gt}$
- Real time: $\lambda PRT_t \cdot (pRT_{gt} - pF_{gt}) + \lambda RRT_t \cdot (rRT_{gt} - rF_{gt})$

With

pF_{gt} : scheduled production of the producer per time interval t (MW)

rF_{gt} : forward committed reserve capacity at a given imbalance interval t (MW)

pRT_{gt} : real-time production of the producer per time interval t (MW)

rRT_{gt}: real-time reserve capacity per time interval t (MW)

Note that the price adders are only applicable in the real-time prices for reserve and energy. The scarcity price mechanism only directly affects the real-time revenues.

Secondly, for **consumers** (being able to provide reserve) the total revenues are computed as follows:

- Forward market: $-\lambda PF_t \cdot dF_{gt} + \lambda RF_t \cdot rF_{gt}$
- Real time: $-\lambda PRT_t \cdot (dRT_{gt} - dF_{gt}) + \lambda RF_t \cdot (rRT_{gt} - rF_{gt})$

With

dF_{gt} : scheduled offtake of the consumer per time interval t (MW)

rF_{gt} : forward committed reserve capacity at a given imbalance interval t (MW)

dRT_{gt} : real-time offtake of the consumer per time interval t (MW)

rRT_{gt}: real-time reserve capacity per time interval t (MW)

Note that the price adders are only applicable in the real-time prices for reserve and energy. The scarcity price mechanism only affects the real-time revenues.

It is worth mentioning that for both producers and consumers, as indicated in the previous section, the price adders for the forward market time frame are considered zero as there is no explicitly ensured back-propagation of prices in the model.

2.3 Mapping of the model on the Belgian context

In the section, the theoretical model summarized in the previous section is mapped to the Belgian context and market design. It is explained how the different elements required to calculate the adder are interpreted for the Belgian market. As the theoretical model was initially not developed for the Belgian or European market design, it is crucial to do this mapping in the best possible way, respecting on the one hand the objectives and needs of the model and on the other hand – as much as possible - the available framework.

2.3.1 General terms

The application of the model to the Belgian system follows the assumptions as provided to Elia by UCL CORE and CREG.

In order to simulate this model in the Belgian context, it is necessary to find a mapping between the terms in the adder formula (Equation 1) and the actual concepts that are available in the Belgian market.

The adder is calculated according to Equation 1:

$$\lambda = MC\left(\sum_g P_g\right) + \frac{T_1}{T_1+T_2}\left(VOLL - \widehat{MC}\left(\sum\nolimits_g p_{g,t}\right)\right)\cdot LOLP_{T_1}\left(R_{T_1}\right) + \frac{T_2}{T_1+T_2}\left(VOLL - \widehat{MC}\left(\sum\nolimits_g p_{g,t}\right)\right)\cdot LOLP_{T_1+T_2}\left(R_{T_1+T_2}\right)$$

If T_1 is fixed at 7,5 minutes and T_1+T_2 at 15 minutes the other parameters can be set as follows for the Belgian context:

- $\widehat{MC}(\sum_g p_{g,t})$ is mapped to the Marginal Incremental Price (MIP) that corresponds to the highest price paid by Elia for upward regulation for a given quarter-hour. This price is published on the website of Elia[6].
- The Value of Lost Load (VOLL) is set at 8.300 €/MWh, as indicated to Elia by CREG and UCL CORE based on a VOLL estimate published in a study of the

[6] www.elia.be/en/grid-data/balancing/imbalance-prices

Federal Planning Bureau[7].

- The Loss of Load Probability (LOLP) function can be approximated by a standard normal distribution. Following the model, the average and standard deviation of this distribution are estimated on the basis of the historically observed system imbalance. Section 2.3.2 details this further.
- The available reserves for the two considered time frames, i.e. R_{T_1} and $R_{T_1+T_2}$, are estimated on the basis of the available balancing means (contracted & non-contracted) in the Belgian system at a given moment. Section 2.3.3 details this further.

2.3.2 Estimating the Loss of Load Probability (LOLP)

A standard normal distribution is used for estimating the LOLP. In order to determine the average and the standard deviation of this distribution the historical system imbalance data is used, published as "SI (MW)" on the website of Elia[6].

Given that the imbalance settlement period in Belgium is 15 minutes, it is straightforward to derive the average and standard deviation of the $LOLP_{15}$ distribution based on the observed average and standard deviation of the quarter-hourly system imbalance.

There is no suitable equivalent available for the 7,5 minute time frame considered by the model. Therefore, for the $LOLP_{7,5}$ distribution is derived from the $LOLP_{15}$ distribution. This requires making assumptions about the correlation of the 15min imbalance with the 7,5min imbalance. UCL CORE makes the assumption that the 15min system imbalance is the result of two perfectly correlated 7.5min imbalance increments, and therefore that the 7,5 min system imbalance is equal to half of the 15min imbalance. The following relationship between the parameters of both LOLP distributions is therefore assumed:

$$\mu_{7,5} = \frac{1}{2} * \mu_{15} \quad \sigma_{7,5} = \frac{1}{2} * \sigma_{15}$$

Equation 7: Relationship between the 15 min and 7,5 min LOLP distribution parameters assuming a normal distribution

With

μ_{15}: average of the $LOLP_{15}$ distribution

$\mu_{7,5}$: average of the $LOLP_{7,5}$ distribution

σ_{15}: standard deviation of the $LOLP_{15}$ distribution

$\sigma_{7,5}$: standard deviation of the $LOLP_{7,5}$ distribution

[7] Federaal Planbureau, D. Devogelaer (March 2014) *"Belgische black-outs berekend: een kwantitatieve evaluatie van stroompannes in België."*, Working Paper 3-14, available online: https://www.plan.be/admin/uploaded/201403170843050.WP_1403.pdf

Note that this full correlation between the 7,5min and the 15min imbalance is a very strong hypothesis, although there is statistical analysis in order to support it (see footnote 4 in page 9). Further work might be useful to verify this further.

Finally, the methodology used by ERCOT partitions the LOLP distribution parameters per season and 4-hour block, thus providing a different LOLP distribution depending on the season (winter, spring, summer and fall) and six blocks grouping several hours of the day.

The quantitative results of the LOLP parameter estimation can be found in section 4.1.

2.3.3 Estimating the available reserve

2.3.3.1 Reserve Available at a 15-minute time horizon

It is necessary to estimate the amount of available reserve available at 15min and 7,5min time horizons. According to the model, this reserve must include reserve coming from demand response, committed resources (committed generation units, with the exception of hydro pumped storage power plants) and from hydro-pumped storage units.

The volume of reserve from committed resources $CGCap_{T_1+T_2}$ and hydro-pumped storage units $HCap_{T_1+T_2}$ is respectively given by Equation 8 and Equation 9.

$$CGCap_{T_1+T_2} = \min(\max(\sum_{g \in GC} (PMax_g - pPF_{gt}), 0), (T_1 + T_2) \cdot RR_g)$$

Equation 8: Estimation of available margin committed resources

With

GC : set of committed resources, excluding hydro pumped storage units

$PMax_g$: nominated P max of committed resources (MW)

pPF_{gt}: scheduled set-point of committed resources, including intraday program change requests (MW)

RR_g : ramp rate of committed resources in production mode (MW/min)

$$HCap_{T_1+T_2} = \min(\max(\sum_{g \in PH} (PHPMax_g - pPHF_{gt}), 0), (T_1 + T_2) \cdot RRPH_g)$$

Equation 9: Estimation of available margin from hydro pumped storage units

With

PH : set of pumped hydro units

$PHPMax_g$: nominated P max of pumped hydro units in production mode (MW)

$pPHF_{gt}$: scheduled set-point of pumped hydro units in production mode, including intraday program change requests (MW)

$RRPH_g$: ramp rate of pumped hydro units in production mode (MW/min)

Note that the hypothesis is made that no energy limitations apply on a 15 min time-horizon, in the sense that any excess capacity that is available in the system is assumed to be able to respond within 15 minutes. This hypothesis seems justified for the purpose of this model as the calculated price adders are applied to the real-time energy and reserve markets and therefore added to a 15min or 7,5min price signal. The (limited) energy left for periods beyond 15min should not impact the signal of the considered 15min period. Indeed, the formulas for determining the remaining reserve and price adders do not take into account energy limitations impacting upcoming 15min periods. In the case that periods beyond 15min would be considered, then energy limitation of hydro pumped storage or demand response units should be taken into account. Note that this approach is consistent with the current way of how energy-limited balancing energy bids are taken into account in the Available Regulation Capacity published by Elia.

Given that the Belgian balancing products are 15min based, the estimation of 15min available reserve can be calculated based on the actual availability of the standard balancing products (contracted and non-contracted).

For this purpose, the information provided by Elia on the dedicated webpage for the publication of the so-called "Available Regulation Capacity (ARC)" is very useful. It provides the necessary remaining available capacity per balancing product[8]. An advantage of relying on ARC, next to being publically available, is that the ARC calculation takes into account limitations and constraints of the balancing products (e.g. the number of activations for demand response products) and the actual technologies underlying the available reserve (e.g. ramping rate of power plants). Although the ARC publication covers a large part of the required data, it needs to be complemented with data related to pumped storage units.

The calculation in ARC takes into account the committed reserve (such as R1, R2 or R3) and calculates the remaining margin following formulas very similar to Equation 8 and Equation 9.

Given the good match between the model approach for estimating the available reserve and the approach in ARC, in agreement with UCL CORE and CREG, it was decided to use ARC data as the basis for estimating the availability of 15min reserve, complemented with a specific calculation for the hydro pumped storage units.

From ARC, the available reserve capacity from the following products is taken into account:

- Available R3 (CIPU and non CIPU)
- Available ICH
- Available CIPU Coordinable margin (excl. hydro pumped storage)

[8] www.elia.be/en/grid-data/balancing/available-regulation-capacity

The above list is complemented with the coordinable margin on the hydro pumped storage units. Given that ARC does not provide the available capacity of upward non-contracted reserves on coordinable (i.e. CIPU) hydro pumped storage units, this is calculated separately, in a bottom-up fashion, according to the model provided by UCL CORE. The available regulation margin from hydro pumped storage units, on a 15min horizon, can be estimated following Equation 9.

To summarize, it is considered that on a 15min time frame the following reserve is available:

- 100% of available R3 (all types)
- 100% of available CIPU Coordinable margin
- 100% of available ICH[9]
- 100% of Hydro Margin

Note that R2 is not considered in the15min time horizon. It will only be considered in the 7,5min time horizon (cf. next section).

Recall also that for this study 2017 data are used, which for instance means that the ICH product is taken into account and that non-CIPU non-contracted R3 (BidLadder) is assumed not to be available. Of course, if applied to another period, the correct balancing product portfolio is to be used.

Inter-TSO reserves are also excluded as there are no guarantees regarding the volume of such reserve that can be made available. If they would be taken into account, this would generally increase the available reserve and therefore have a dampening effect on the calculated price adder values.

2.3.3.2 Reserve Available at a 7,5-minute time horizon

Whereas the most important balancing timeframe in the Belgian market is 15min, i.e. the imbalance settlement period, the 7,5min timeframe is only explicitly used in the context of the R2 response time. This means that for several other aspects such as the remaining reserve, the estimation for the 7,5min time horizon requires additional assumptions.

The only reserve that is fully available on this time horizon is R2. According to the product definition, R2 must be able to ramp up to the maximum available volume within 7,5 minutes.

However, it would be too restrictive to limit the available reserve at 7,5 min just to R2. It is arguable that production-based reserves, CIPU Coordinable Margin (including the hydro pumped storage margin) and R3 CIPU, should be able to ramp up and provide part of the 15min reserve within 7,5 minutes. Also non-production based reserve (R3

[9] For the simulation, we used data from 2017. In 2017, ICH was still an available balancing product.

Non CIPU) should also be able to start providing part of their reserve within a 7,5 min time-horizon. Likewise for ICH this could be the case, nevertheless for the study it is assumed that ICH volume is not available at 7,5min, which incurs in a conservative estimation of the 7,5min reserve and consequently an overestimation of the 7,5min price adder.

Therefore, for the 7,5 min available reserve, two scenarios are considered:

- *Base case scenario:* In addition to R2, 50% of all 15min reserve, as described in 2.3.3.1, is available at 7,5 min
- *Sensitivity scenario*: In addition to R2, 50% of only the generation based 15min reserve, that is CIPU Coordinable Margin (incl. hydro pumped storage margin) and R3 CIPU, is available at 7,5min.

7,5min reserve base case scenario	**7,5min reserve sensitivity Scenario**
• 100% of available R2 • 50% of available R3 (CIPU **and Non CIPU**) • 50% of available CIPU Coordinable margin • 50% of Hydro Margin	• 100% of available R2 • 50% of available R3 CIPU **(R3 Non CIPU is excluded)** • 50% of available CIPU Coordinable margin • 50% of Hydro Margin

Table 1: Reserve types accounted for in each 7,5min reserve scenario

2.3.4 Settlement

2.3.4.1 Estimating the available real-time reserve capacity and real-time energy of production units

In section 2.2.2 it is explained that the settlement of producers being able to provide reserve capacity requires the calculation of the actual real-time available reserve. It is needed to define a methodology for calculating the real-time available reserve from producers.

In case of a power plant, there are two different situations that can occur:

- The actual production of a producer is *above* the DA nominated production (PNom)
- The actual production of a producer is *below* the DA nominated production (PNom)

The first case is illustrated in Figure 1 for a hypothetical power plant. For simplicity, the example assumes that the available day-ahead reserve is equal to the difference between PMax[10] and PNom and that the available real-time reserve is equal to the difference between PMax and the actual measured output from the power plant (PMeas). It should be noted that this is a very simplified calculation of the available reserve, as it implies an infinite ramping rate from the unit. It also does not consider changes to the production program that may be communicated during the intraday processes, i.e. the so-called IntraDay Program Change Requests (IDPCR).

Note, however, that the ramping rate constraints are taken into account in the simulations for calculating the available reserve. For the sake of clarity in illustrating the concept of settlement in Figure 1, ramping rate constraints are ignored.

In the example of Figure 1 it is shown that the positive difference between PMeas and PNom yields higher revenues for the unit in the energy market, but at the same time reduces the available real-time reserve, implying as well a reduction in the hypothetical revenue from the real-time reserve market.

[10] PMax is the maximum output a power plant can reach. This value is communicated to Elia as stipulated in the CIPU contract

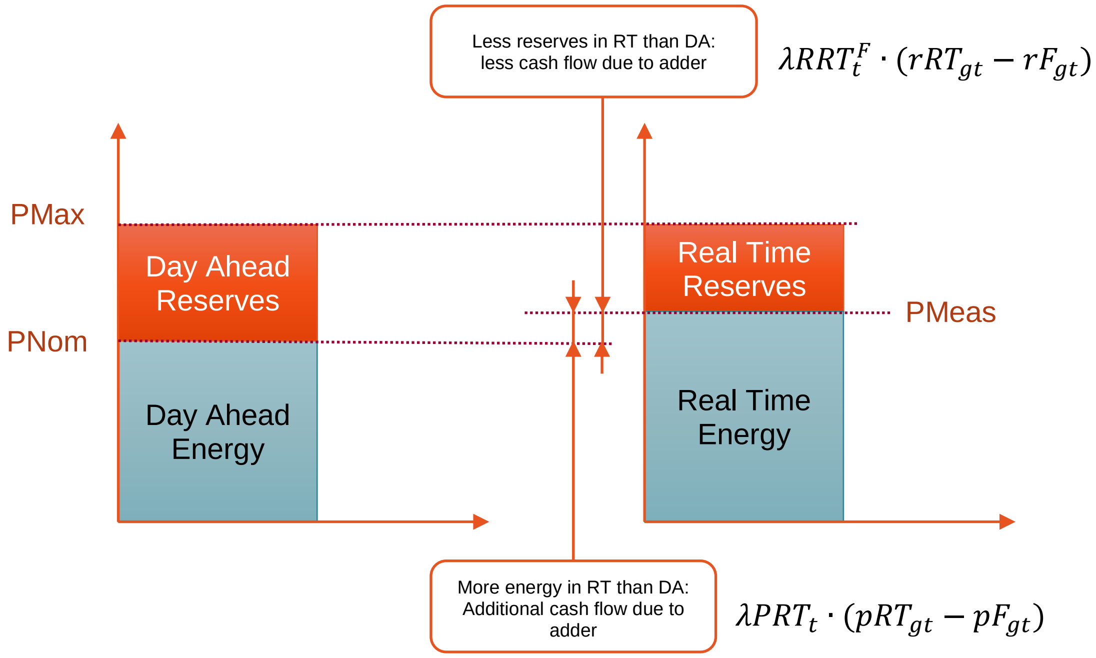


Figure 1: Producer with intraday production above the nominated production

The opposite situation, where the power plant output is below the announced day-ahead production, is shown in Figure 2. Under these circumstances, the negative difference between the PMeas and PNom yields lower revenues for the unit in the energy market, but at the same time increases the available real-time reserve, with an increase in the hypothetical revenue from the real-time reserve market.

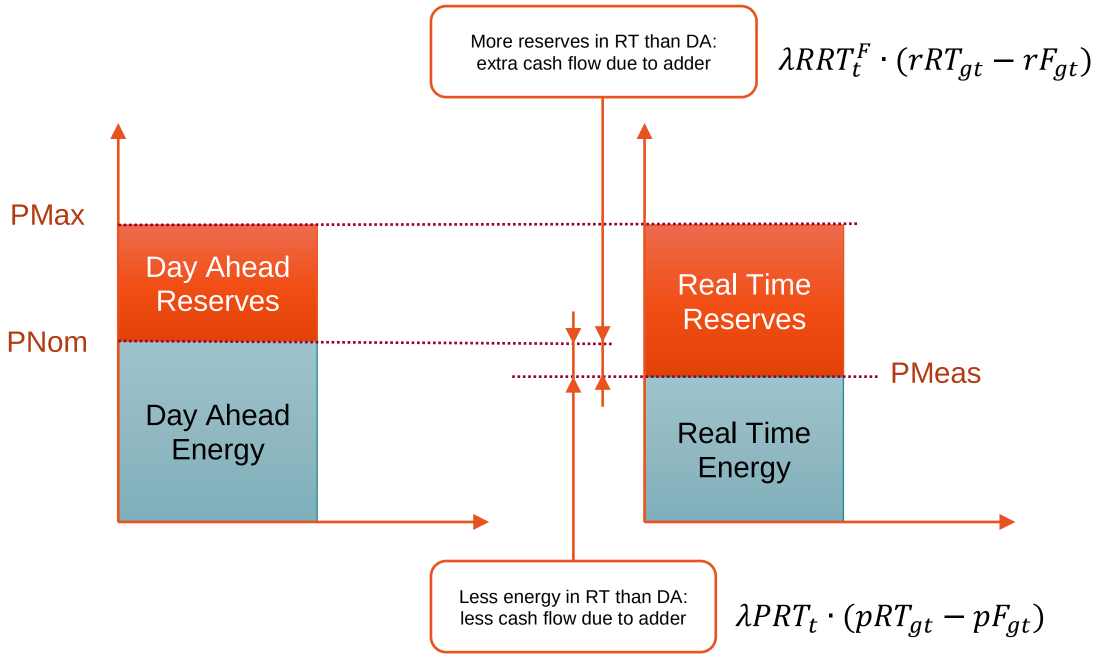


Figure 2: Producer with intraday production below the nominated production

As mentioned in Section 2.2.2.1 reserve activation will be accounted for as extra production (PMeas above PNom) and thus remunerated through the real-time energy market (rather than via the current activation remuneration mechanisms defined for the balancing products). However, on the other hand, reserve activation, with an increment of actual output (PMeas) might reduce the available reserve in real time and thus incur a 'penalization' of this lower volume because of the price adder.

As mentioned above in the text, the approach shown in the figures for calculating the reserves is strongly simplified as it does not consider ramping rate constraints.

The precise calculation should be done taking the ramping rate constraints in consideration as follows:

The day ahead reserve can be calculated in a similar way as the available reserve (Equation 8) by substituting the set-point of the unit by the day-ahead nomination:

$$CGCDAap_{T_1+T_2} = \min(\max(\sum\nolimits_{g \in GC} (PMax_g - pPFDA_{gt}), 0), (T_1 + T_2) \cdot RR_g)$$

Equation 10: Estimation of available day-ahead margin of committed resources

With

GC : set of committed resources, including hydro pumped storage units

$PMax_g$: nominated Pmax of committed resources (MW)

$pPFDA_{gt}$: scheduled set-point (i.e. nomination) of committed resources on day-ahead (MW)

RR_g : ramping rate of committed resources in production mode (MW/min)

The real-time available reserve can be calculated in a similar way as the available reserve (Equation 8) by substituting the set-point of the unit by the actual output from the unit:

$$CGCRTap_{T_1+T_2} = \min(\max(\sum\nolimits_{g \in GC} (PMax_g - pProd_{gt}), 0), (T_1 + T_2) \cdot RR_g)$$

Equation 11: Estimation of real-time available margin from committed resources

With

GC : set of committed resources, including hydro pumped storage units

$PMax_g$: nominated P max of committed resources (MW)

$pProd_{gt}$: actual production of committed resources on day-ahead (MW)

RR_g : ramping rate of committed resources in production mode (MW/min)

Note that for coherency with section 2.3.3.2, Equation 10 and Equation 11 will be used for calculating precisely the available reserve at T_1+T_2 (15min), and that 50% of this value will be used as an estimate of the available reserve at T_1 (7,5min). Only in the particular case of R2, Equation 10 and Equation 11 will be used in order to evaluate the available volume of reserve taking into account the ramping rate constraints at 7,5min.

2.3.4.2 Estimating the real-time reserve capacity available by ICH and the real-time energy provided by ICH

In section 2.2.2 it is explained that the settlement of consumers being able to provide reserve requires the calculation of the actual real-time available reserve. The only product in 2017 being 'purely' demand response was ICH.

The available volume of ICH is calculated by ARC, on the basis of the day-ahead nomination, as follows[11]:

$$ICH_{qh} = Max\left[0; \left(\sum_{AP} Nom_{AP,qh}\right) - SL_{TP}\right]$$

Equation 12: Calculation of ICH volume per contract

With

$Nom_{AP,qh}$ The nomination of an Access Point for a quarter hour qh (when this nomination does not exist, it is replaced by the value 0).

SL_{TP} The Shedding Limit, or minimum offtake, for the tariff period corresponding to quarter hour qh.

For calculating the actual available ICH volume in real time, for a given contract, the nomination should be replaced by the actual offtake in Equation 12, thus yielding Equation 13:

$$ICH_{qh} = Max\left[0; \left(\sum_{AP} Offtake_{AP,qh}\right) - SL_{TP}\right]$$

Equation 13: Estimation of real-time ICH volume per contract

With

$Offtake_{AP,qh}$ The actual metered offtake of an Access Point for a quarter hour qh (when this nomination does not exist, it is replaced by the value 0).

$SL_{Contrat,TP}$ The Shedding Limit for the tariff period corresponding to quarter hour qh.

As in the case of producers, two different situations can be distinguished:

- ICH total offtake is *above* the announced offtake in DA Nomination
- ICH total offtake is *below* the announced offtake in DA Nomination

[11] See www.elia.be/~/media/files/Elia/Grid-data/Balancing/9427-Available%20Regulation%20Capacity_EN_V2.pdf

The first situation is illustrated in Figure 3. By increasing the offtake, the ICH provider makes more reserve available in real time than in day ahead, as there is more margin above the shedding limit, and this yields an extra remuneration to the ICH provider. On the other hand, it is assumed that the ICH provider has to pay for the difference between prices for real-time energy and day-ahead energy.

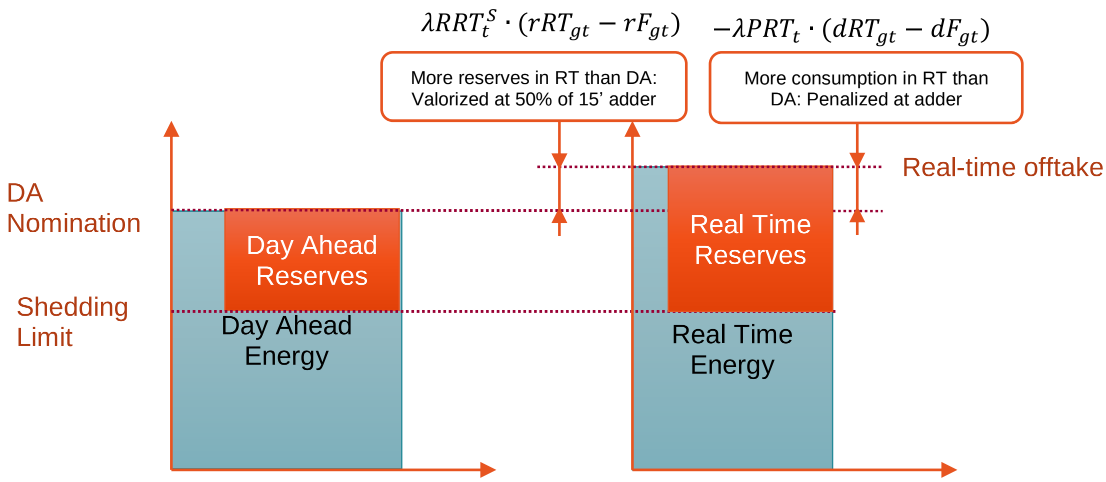


Figure 3: ICH with intraday offtake above the nominated offtake

The opposite situation, where the offtake is below the announced offtake in the DA nomination, is shown in Figure 4. By decreasing the offtake, the ICH provider makes less reserve available in real time than in day-ahead, thus implying a payback. On the other hand, the ICH provider can resell on the real-time market the energy bought on the day-ahead market but not used in real-time and thus receives the difference between price for the energy bought on the day-ahead market and the price for the energy actually used on the real-time market.

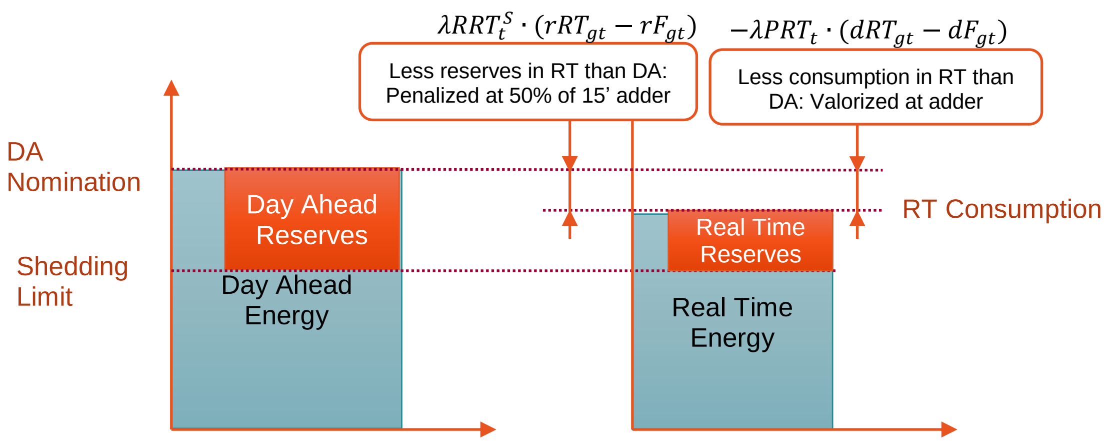


Figure 4: ICH with intraday offtake above the nominated offtake

2.3.4.3 Estimating the real-time energy provided by grid users

The grid users, i.e. those not participating in ICH, are assumed to play only in the real-time energy market. It is assumed by the model that they do not participate in the reserve market, nor in day ahead neither in real-time.

The impact of the price adder for grid users therefore only affects the difference between the energy bought on DA and the energy bought/sold on real-time. The energy bought on DA is based on the DA nomination from the grid user. In the DA nomination, the grid user announces its intended consumption.

As with producers and ICH providers, two different situations are distinguished:

- Grid user offtake is *above* the announced offtake in the DA Nomination
- Grid user offtake is *below* the announced offtake in the DA Nomination

If the real-time offtake of the grid user is above the DA nomination, it implies that the grid user will have to buy this extra energy and will thus be penalized by the price adders on the real-time energy price.

On the other hand, if the real-time offtake of the grid user is below the DA nomination, it implies that the grid user can re-sell this extra energy not being consumed and will thus benefit from the price adders on the real-time energy price.

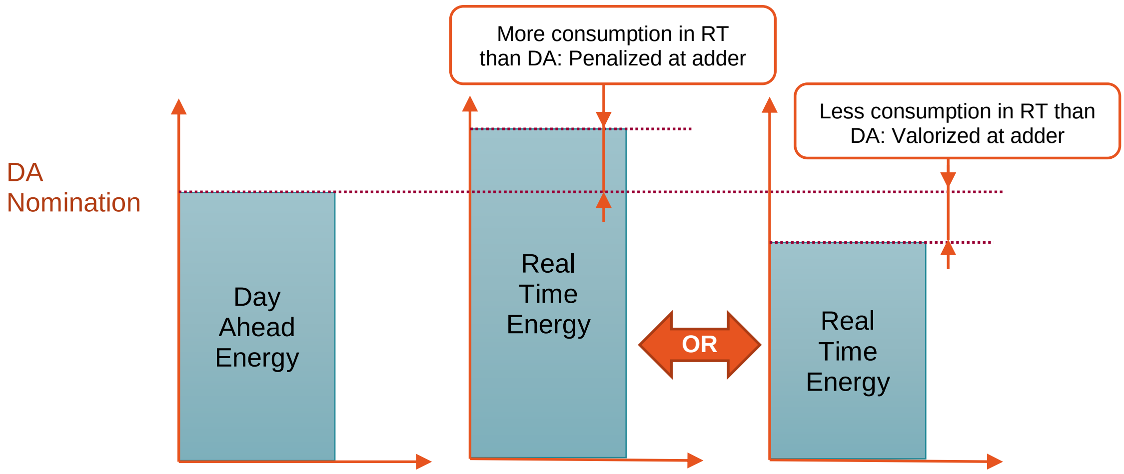


Figure 5: Settlement of grid users. The impact of the price adder is on the delta between the day-ahead energy and real-time energy

2.4 Summary of the observations related to the detailed modelling

The mapping of the Belgian market design to the scarcity pricing model requires several assumptions, which should be kept in mind when interpreting the results obtained in later sections of this study.

Firstly, whereas the 15min time frame is a cornerstone in the Belgian market design as it is the imbalance settlement period, there is no such clear link for the 7,5min time frame used by the model. For instance, this required taking extra assumptions with respect to the distribution function parameters for the 7,5min compared to the (observed) 15min distribution function parameters. Also the definition of which reserves are considered to be available at 7,5min requires assumptions, and the effect of these assumptions was investigated by introducing a sensitivity analysis of the adder with respect to available R3 non-CIPU reserves.

Secondly, when estimating the available reserve, the starting point for the choices made for mapping the model to the Belgian context is the information available to Elia from the system. Elia has a clear view on contracted reserves in the context of its ancillary services products and, for some part of the system, also on its remaining margin (i.e. margin on coordinable CIPU units, including pumped storage hydro units). However, for several potential sources of reserves, Elia has no view on the margin (or even their existence). There may exist, for instance, demand response potential that it is not made visible to Elia via its balancing products. In that respect, the hypotheses made are believed to be the best possible given the available context, however these hypotheses could entail an underestimation of the available reserve.

Finally, and more fundamentally, there is a significant difference between the assumed market organization in the model and the Belgian reality. In the Belgian market design, there is, for instance, no real-time reserve market present. It has nevertheless been assumed in this study in order to be able to remain as close as possible to the provided scarcity pricing model. This strong assumption of course determines greatly the revenue streams from a scarcity pricing mechanism and therefore also its effectiveness in providing the intended investment signals.

3 Description of the data used for the model

In this section, the data used to calibrate for the model are described in more detail. Building further on the choices explained in the previous section, a detailed overview is provided. Note that 2017 data are used for the calibration and simulations. Where possible, preference is given to the use of publically available data. Unfortunately, not all inputs required for the model are publically available.

3.1 Data used for the determination of the LOLP distribution and price adder

3.1.1 System Imbalance (SI)

The system imbalance is used in order to calculate the parameters of the LOLP distribution and is based on the SI data that are publically available on the following website:

http://www.elia.be/en/grid-data/balancing/imbalance-prices

In this publication, the System Imbalance can be found in the "SI (MW)" column and it is given per quarter-hour.

3.1.2 Marginal Incremental Price (MIP)

The Marginal Incremental Price is used to calculate the price adder, as shown by Equation 1, and is based on the MIP data that are publically available on the following website:

http://www.elia.be/en/grid-data/balancing/imbalance-prices

In this publication, the Marginal Incremental Price (MIP) can be found in the "MIP (€/MWh)" column and it is given per quarter-hour.

3.1.3 Available Regulation Capacity (ARC)

The Available Regulation Capacity data is used in order to determine the available reserve margins and is based on the ARC data that are publically available on the following website:

http://www.elia.be/en/grid-data/balancing/available-regulation-capacity

The available reserve margins are provided per quarter hour and product. These margins take into account the limitations and constraints of the products (such as the limited number of activations and the ramping rate of units).

Note that, in this publication, R3 CIPU and R3 Non CIPU are aggregated and no distinction is made between the two. Additional non-public data available to Elia is used in order to split the volume of R3 into CIPU and Non-CIPU.

Note that, in the ARC publication, the margin from hydro-pumped storage units is not provided (cf. 2.3.3.1).

3.1.4 Hydro-pumped storage data

In order to calculate the hydro pumped storage capacity, as shown in Equation 9, the following data about hydro-pumped storage units are required:

- $PHPMax_g$: nominated P max of pumped hydro units in production mode (MW)
- $pPHF_{gt}$: scheduled set-point of pumped hydro units in production mode, including intraday program change requests (MW)
- rPH_{gt} : committed forward reserve (R_1, R_2 and R_3) on pumped hydro units (MW)
- $RRPH_g$: ramp rate of pumped hydro units in production mode (MW/min)

Most of this data is not publically available from the Elia website. However, the necessary data are retrieved by Elia in the context of the production nomination procedure (as stipulated in the CIPU contract). Note that production data related to hydro pumped storage units can be consulted at ENTSO-E Transparency Platform[12].

3.2 Data used for the settlement simulations

3.2.1 Power plant Day-Ahead nomination and actual production

In section 2.2.2 it is explained that the settlement simulation requires having both the forward production and the actual production. The Day-Ahead (DA) production nomination is used as forward production and the metered production as actual production.

The Day-Ahead production nomination is received by Elia in the framework of the CIPU contract. Metering data of actual production for a set of power plants is available to Elia.

Neither of these data items are publicly available on the Elia website.

Note that, for the settlement simulations, only a representative subset of the production installations is used.

3.2.2 Offtake points nomination and actual consumption

In section 2.2.2 it is explained that the settlement simulation for offtake points requires having both the forward consumption and the actual consumption. The Day-Ahead (DA) consumption nomination is considered as the forward consumption, and the metered consumption as the actual consumption.

[12] ENTSO-E Transparency Platform: https://transparency.entsoe.eu/

The DA consumption nomination is received in the framework of the BRP contract. Elia has access to metering data of actual consumption. Note that this data is not publicly available. Note that, for the settlement simulations, only a representative subset of the of grid users is used.

3.2.3 ICH DA nomination, actual consumption and shedding limit

The settlement of ICH requires, in addition the data related to consumption (cf. previous section (3.2.2)), the shedding limit (cf. section 2.3.4).

The shedding limit is a contractual parameter that is not publically available.

4 Simulation results

4.1 LOLP distribution parameters

The LOLP is calculated based on historically observed system imbalances, differentiated per season and per block of hours of the day.

The seasonal and hour block partitioning has been determined by UCL CORE on the basis of the implementation of scarcity pricing in the Texas market, as represented in Table 2 and Table 3.

Season	Months
Winter	December, January, February
Spring	March, April, May
Summer	June, July, August
Fall	September, October, November

Table 2: Season definition

Hour block name	Hour period
1, 2, 23, 24	From 22:00 to 02:00
3-6	From 02:00 to 06:00
7-10	From 06:00 to 10:00
11-14	From 11:00 to 14:00
15-18	From 14:00 to 18:00
19-22	From 18:00 to 22:00

Table 3: 4-hour block definition

To calculate the parameters of each of the 24 LOLP distributions, the actual 2017 quarter-hourly system imbalance data is partitioned per season and 4-hour block. For each of these partitions, the average (μ) and standard deviation (σ) of the system imbalance are calculated in order to derive the values of table 4.

Winter			Spring		
Hour Block	**μ_{15} (MW)**	**σ_{15} (MW)**	**Hour Block**	**μ_{15} (MW)**	**σ_{15} (MW)**
1,2,23,24	29,53	165,37	1,2,23,24	28,37	147,85
3-6	23,58	147,76	3-6	42,33	131,26
7-10	16,58	181,26	7-10	27,75	151,34
11-14	-20,91	224,07	11-14	68,37	174,89
15-18	8,01	162,40	15-18	68,96	161,48
19-22	9,82	147,19	19-22	9,01	134,32
Summer			Fall		
Hour Block	**μ_{15} (MW)**	**σ_{15} (MW)**	**Hour Block**	**μ_{15} (MW)**	**σ_{15} (MW)**
1,2,23,24	20,14	133,09	1,2,23,24	29,21	138,74
3-6	42,49	111,54	3-6	28,94	105,88
7-10	25,82	132,13	7-10	-11,19	142,80
11-14	34,79	154,37	11-14	18,55	164,95
15-18	47,14	140,34	15-18	0,24	142,80
19-22	13,54	108,87	19-22	-10,85	147,20

Table 4: System Imbalance average (μ) and standard deviation (σ) per season and 4-hour block for 2017[13].

Note that for the 7,5min time frame it is assumed that the average and standard deviation are half of those that are estimated for the 15min time frame, cf. section 2.3.2.

The histograms of the partitioned system imbalance distributions are represented in

[13] A positive/negative average system imbalance (μ) indicates that the zone is, on average, long/short at the considered season and hour block.

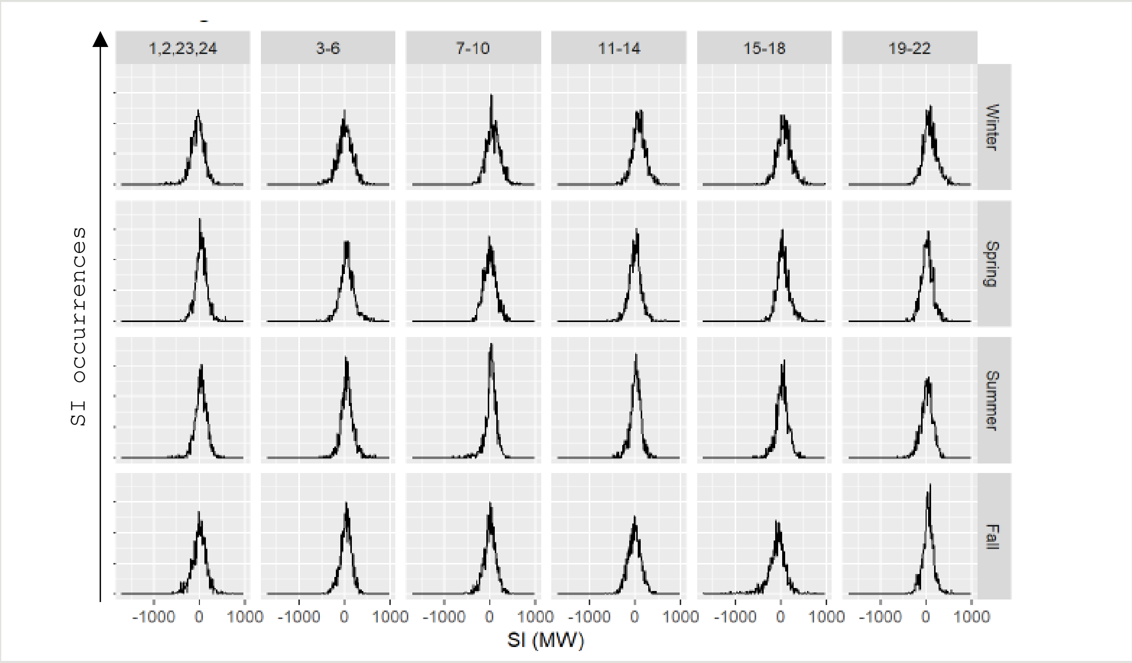


Figure 6: System Imbalance histograms, per season and 4-hour block for 2017. The vertical axis provides the number of SI occurrences.

Table 4 and Figure 6 illustrate already that the probability distribution functions for the considered blocks differ. The example in Figure 7 shows this in a clearer way. The histograms of the winter and summer 4-hour block 19-22 are compared in this figure.

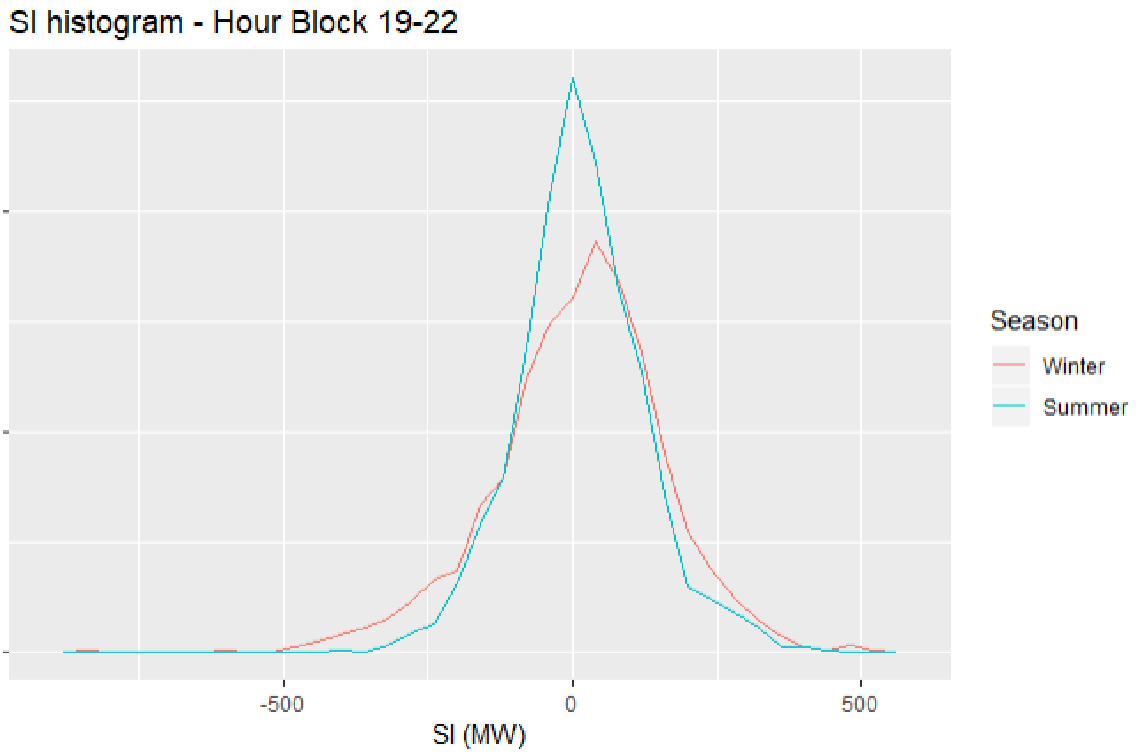


Figure 7: Summer and Winter 4-hour block 19-22 system imbalance histograms for 2017

From Figure 7 it can be seen that the winter 19-22 distribution shows more occurrences in the negative SI range (left-hand tail), especially in the -250 MW to -500 MW range, than the summer distribution. It can be deduced that, during winter, from 18:00 to 22:00, there are more situations with negative system imbalance than in the summer, from 18:00 to 22:00.

The results that are shown in Table 4 also illustrate this behavior. The winter 19-22 distribution has a lower average and higher standard deviation than the summer 19-22 distribution.

These differences in the distribution parameters do have an impact in the calculation of the LOLP. For instance, in the winter-summer 19-22 example, for the same available remaining reserve, the LOLP will be lower with the summer 19-22 distribution than with the winter 19-22 distribution. Consequently, for the same available remaining reserve the price adder will be higher during the winter than during the summer during the considered hours.

4.2 Price adder results

4.2.1 Price adder calculation

Following the UCL CORE model, there are two different adders distinguished, the 7,5 min adder and the 15 min adder. These adders are the terms being summed in Equation 1.

The 15 min adder is calculated by taking into account the amount of available reserve that can react within 15 min (which is the duration of the balancing time unit in Belgium) using the following formula:

$$adder_{15min} = \frac{T_2}{T_1 + T_2}\left(VOLL - \widehat{MC}\left(\sum\nolimits_g p_{g,t}\right)\right) \cdot LOLP_{T_1+T_2}\left(R_{T_1+T_2}\right)$$

With

VOLL: Value of Loss of Load

$\mathrm{T_1 + T_2}$: 15 minutes

$\widehat{\mathrm{MC}}(\sum_g \mathrm{p_{g,t}})$: Incremental cost for meeting an additional increment in demand. The Marginal Incremental Price can be used as a proxy

$\mathrm{R_{T_1+T_2}}$: Reserve capacity that can respond within $\mathrm{T_1 + T_2}$ minutes

$\mathrm{LOLP_{T_1+T_2}(R_{T_1+T_2})}$: Loss of Load Probability at $\mathrm{T_1 + T_2}$ minutes with $\mathrm{R_{T_1+T_2}}$ as available reserve.

This LOLP can be calculated as follows:

$$\mathrm{LOLP_{T_1+T_2}(R_{T_1+T_2})} = \mathrm{P[Imb > R_{T_1+T_2}]} = 1 - \mathrm{P[Imb \leq R_{T_1+T_2}]}$$

$$= 1 - \mathrm{P}\left[\frac{\mathrm{Imb} - \mu_{15}}{\sigma_{15}} \leq \frac{\mathrm{R}_{\mathrm{T}_1+\mathrm{T}_2} - \mu_{15}}{\sigma_{15}}\right] = 1 - \ \Phi(\frac{\mathrm{R}_{\mathrm{T}_1+\mathrm{T}_2} - \mu_{15}}{\sigma_{15}})$$

With Φ being the cumulative distribution function of the standard normal distribution. The average and standard deviation values are taken from Table 4.

The 7,5 min adder is calculated by taking into account the amount of available reserve that can react within 15 min using the following formula:

$$adder_{7,5min} = \frac{T_1}{T_1 + T_2}\left(VOLL - \widehat{MC}\left(\sum\nolimits_g p_{g,t}\right)\right) \cdot LOLP_{T_1}\left(R_{T_1}\right)$$

With

VOLL: Value of Loss of Load

T_1: 7,5 minutes

$\widehat{\mathrm{MC}}(\sum_g \mathrm{p}_{g,t})$: Incremental cost for meeting an additional increment in demand. The Marginal Incremental Price can be used as a proxy

$\mathrm{R}_{\mathrm{T}_1}$: Reserve capacity that can respond within T_1 minutes

$\mathrm{LOLP}_{\mathrm{T}_1}\left(\mathrm{R}_{\mathrm{T}_1}\right)$: Loss of Load Probability at T_1 minutes with $\mathrm{R}_{\mathrm{T}_1}$ as available reserve.

This LOLP can be calculated as follows:

$$LOLP_{T_1}\left(R_{T_1}\right) = P\left[Imb > R_{T_1}\right] = 1 - P\left[Imb \leq R_{T_1}\right]$$

$$= 1 - P\left[\frac{Imb - \mu_{7,5}}{\sigma_{7,5}} \leq \frac{R_{T_1} - \mu_{7,5}}{\sigma_{7,5}}\right] = 1 - \ \Phi(\frac{R_{T_1} - \mu_{7,5}}{\sigma_{7,5}})$$

With Φ being the cumulative distribution function of the standard normal distribution. The average and standard deviation values at 7,5 min can be taken as 50% of the parameters in Table 4, following Equation 7 with the hypothesis explained in 2.3.2 according to which the 15-minute imbalance is the result of two perfectly correlated 7.5-minute imbalance increments.

4.2.2 Price adder results for 2017

This section describes the results for the calculated 15min and 7,5min (base case and sensitivity) price adders for 2017. Average and maximum values are provided as well as a view on the duration curve for the price adders. Whereas in this section results are purely descriptive, in the next section a deeper analysis of the obtained results will be provided by looking at particular situations which should allow the reader to gain a better insight in the dynamics that are underlying the adder calculation.

4.2.2.1 15min price adder results

Table 5 and Figure 8 provide the monthly maximum and average 15min price adder for 2017.

Month	Average 15 min adder (€/MWh)	Maximum 15 min adder (€/MWh)
2017-01	0,00 €/MWh	0,32 €/MWh
2017-02	0,00 €/MWh	0,00 €/MWh
2017-03	0,00 €/MWh	0,00 €/MWh
2017-04	0,00 €/MWh	0,00 €/MWh
2017-05	0,00 €/MWh	0,00 €/MWh
2017-06	0,00 €/MWh	0,00 €/MWh
2017-07	0,00 €/MWh	0,00 €/MWh
2017-08	0,00 €/MWh	0,00 €/MWh
2017-09	0,00 €/MWh	0,00 €/MWh
2017-10	0,00 €/MWh	0,00 €/MWh
2017-11	0,02 €/MWh	35,59 €/MWh
2017-12	0,01 €/MWh	17,63 €/MWh
2017 full year	**0,00 €/MWh**	**35,59 €/MWh**

Table 5: 15min adder simulation results for 2017

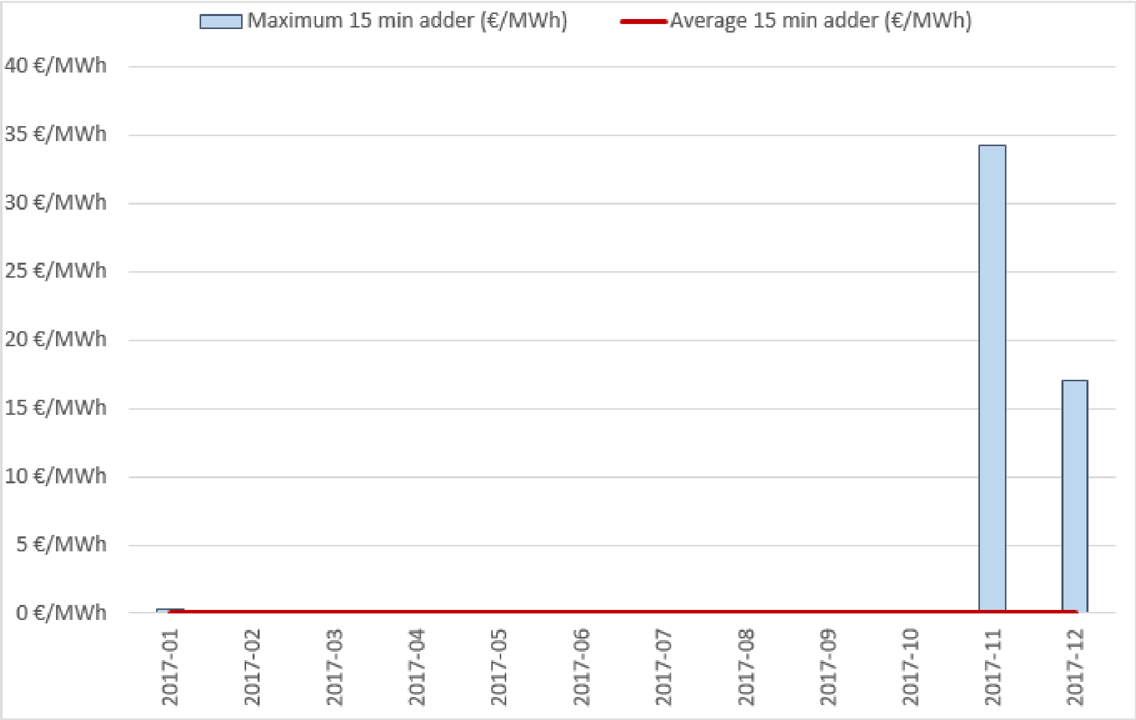


Figure 8: Monthly average and maximum 15 min price adder for 2017

Figure 9 shows the duration curve of the 15min adder, i.e. the number of quarter-hours for which the price adder is above a given value.

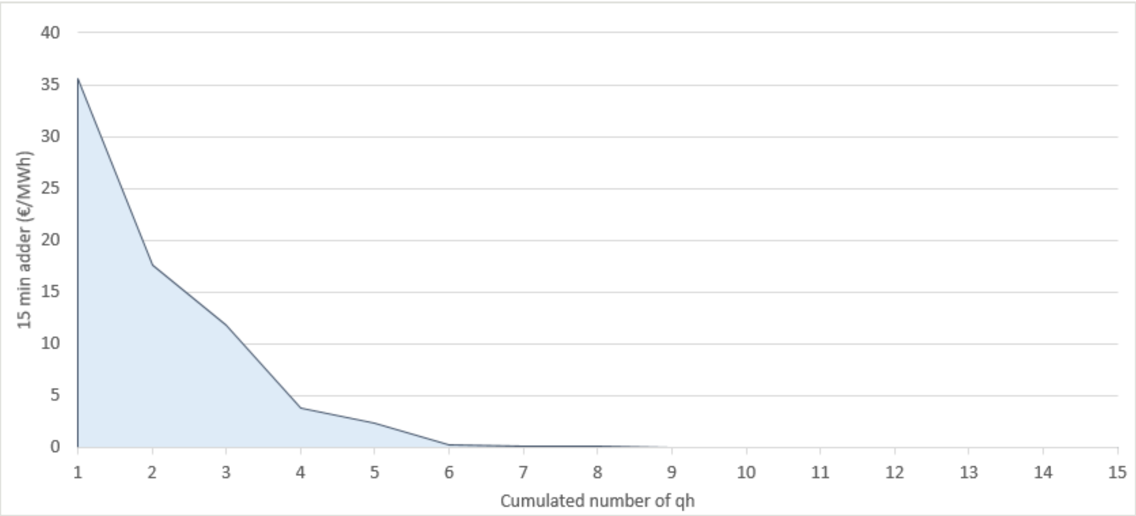


Figure 9: 15 min adder duration curve

The above Table 5, Figure 8 and Figure 9 lead to the following observations for 2017:

- Overall, the 15min price adder does not reach very highly values. The average is close to zero and the maximum reaches 35,59 €/MWh.
- During almost all quarter hours the 15min price adder is zero.
- There are only three quarter hours with a 15min price adder above 5 €/MWh.

4.2.2.2 7,5min price adder results

Table 6 and Figure 10 provide the results for the 7,5min adder calculation for 2017. Per month the maximum and average 7,5min price adders are shown. These have been computed for both the base case (including 50% of the R3 non-CIPU reserve in the 7,5min reserve) and the sensitivity (excluding all R3 non-CIPU reserve from the 7,5min reserve).

	Base Case: 50% of R3 non-CIPU included in the 7,5min reserve		Sensitivity: R3 Non CIPU excluded from 7,5min reserve	
Month	Average Adder (€/MWh)	Maximum Adder (€/MWh)	Average Adder (€/MWh)	Maximum Adder (€/MWh)
01-2017	0,00 €/MWh	0,02 €/MWh	0,02 €/MWh	13,20 €/MWh
02-2017	0,00 €/MWh	0,00 €/MWh	0,00 €/MWh	0,01 €/MWh
03-2017	0,00 €/MWh	0,00 €/MWh	0,00 €/MWh	0,00 €/MWh
04-2017	0,00 €/MWh	0,00 €/MWh	0,00 €/MWh	0,00 €/MWh
05-2017	0,00 €/MWh	0,00 €/MWh	0,00 €/MWh	0,00 €/MWh
06-2017	0,00 €/MWh	0,00 €/MWh	0,00 €/MWh	0,00 €/MWh
07-2017	0,00 €/MWh	0,00 €/MWh	0,00 €/MWh	0,00 €/MWh
08-2017	0,00 €/MWh	0,00 €/MWh	0,00 €/MWh	0,00 €/MWh
09-2017	0,00 €/MWh	0,00 €/MWh	0,00 €/MWh	0,00 €/MWh
10-2017	0,00 €/MWh	0,00 €/MWh	0,01 €/MWh	20,39 €/MWh
11-2017	0,01 €/MWh	10,85 €/MWh	1,31 €/MWh	1264,94 €/MWh
12-2017	0,00 €/MWh	11,13 €/MWh	0,34 €/MWh	838,35 €/MWh
2017 full year	0,00 €/MWh	11,13 €/MWh	0,14 €/MWh	1264,94 €/MWh

Table 6: 7,5 min adder simulation results

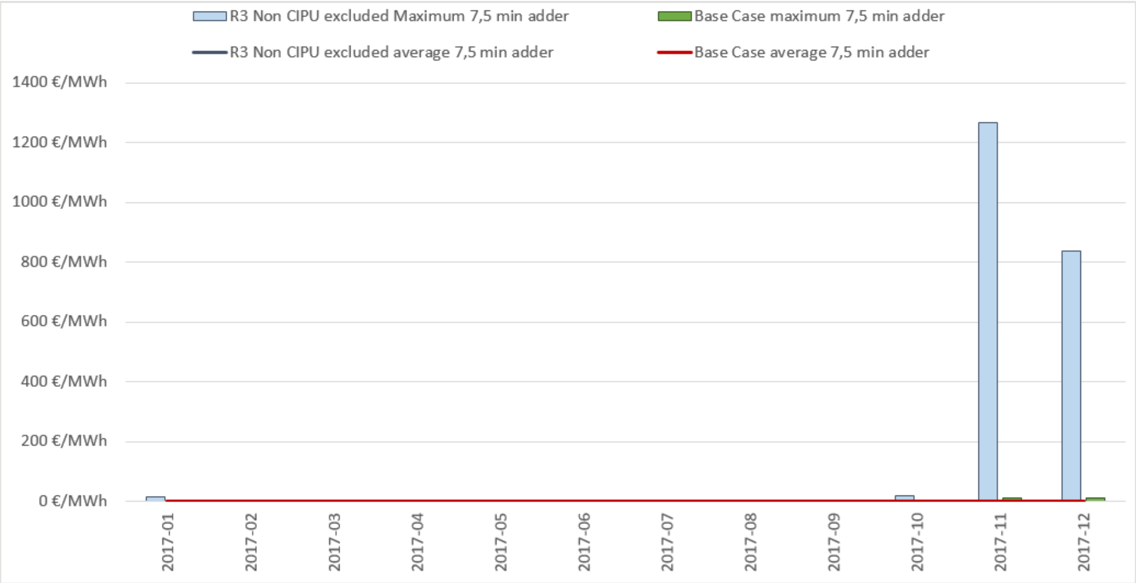
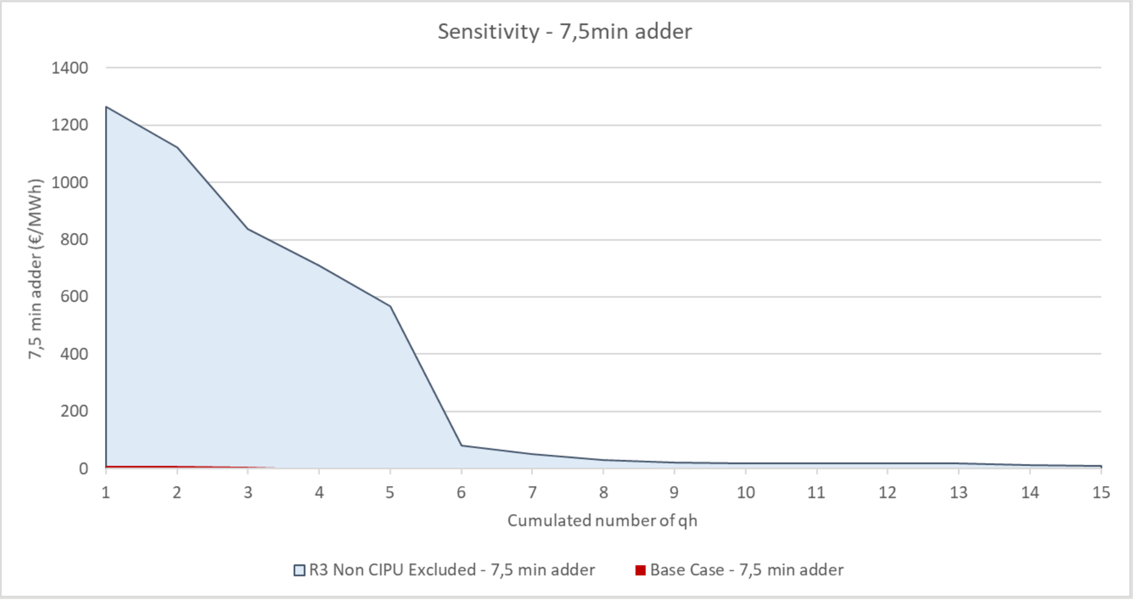


Figure 10: Monthly and average 7,5 min adder in base case and sensitivity

Figure 11 (page 40) shows the duration curves for both cases of the 7,5min adder for 2017.

From Table 6, Figure 10 and Figure 11 it can be observed that:

- Like for the 15min price adder, the 7,5min price adder does not reach high values in the base case. The 2017 average is close to zero in the base case and the maximum reaches 11,3 €/MWh. However, in the sensitivity case significantly higher values are reached with a maximum of 1.264,94 €/MWh. Note that this value nevertheless remains far below the assumed level of Value of Lost Load (8.300 €/MWh).The average in the sensitive case remains low; i.e. 0,14 €/MWh.
- Like for the 15min price adder, during almost all hours the 7,5min price adder is zero, both in the base case and the sensitivity case.
- In the base case, there are only three quarter hours with a 7,5min price adder above 3 €/MWh. In the sensitivity case, there are four quarter hours with a 7,5min price adder above 600 €/MWh and 20 quarter-hours with a 7,5min price adder above 5 €/MWh.



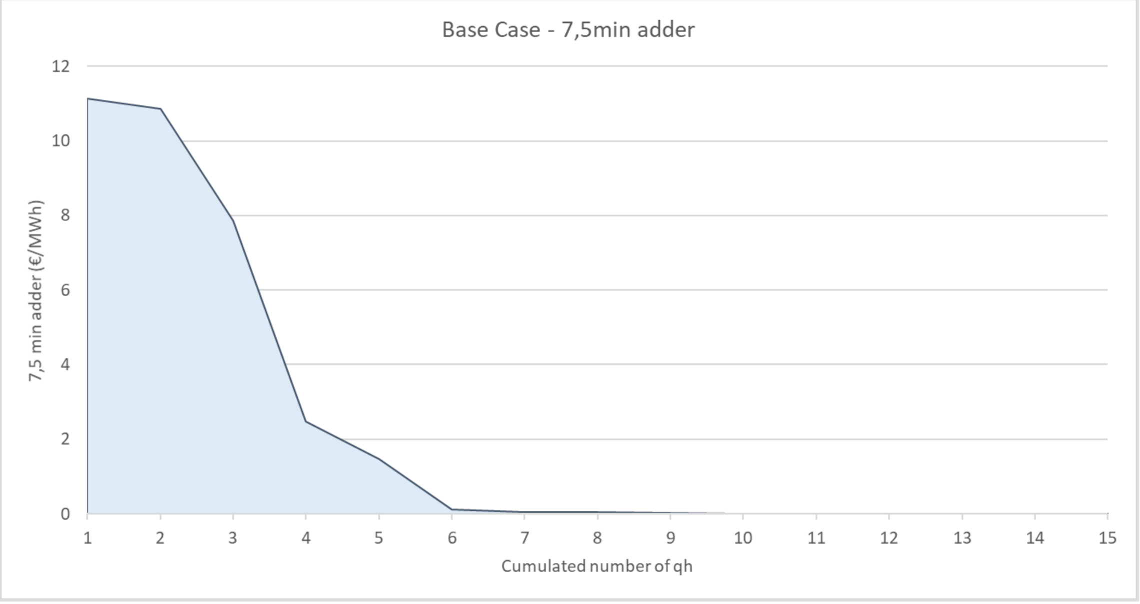


Figure 11: 7,5min adder duration curve. The upper chart shows the two cases together, the lower chart gives the base case alone with a different scale for the Y-axis.

4.2.3 Analysis of price adder peak formation

Having obtained the price adder results for 2017, as shown in the previous section, in this section these results are further analyzed in order to gain a better understanding on the price adder behavior.

As shown in the previous section, the price adder peaks occur during the months of November and December 2017. The remainder of this section therefore only focusses on these months.

In Figure 12 and Figure 13 (pages 42 and 43 respectively), the daily maximum price adder peak is plotted for the period November-December 2017, in the Base Case and sensitivity case respectively. This means that, for each day, only one 7,5/15 minute period is shown, i.e. the period with the highest observed price adder.

Whereas Figure 13 shows the results with R3 non CIPU being considered as being capable to respond at 50% of its capacity within 7,5 minutes, Figure 13 takes a more conservative scenario where R3 non CIPU is excluded from the available reserve in 7,5 minutes. Obviously, the latter approach results in more extreme peaks for the 7,5min price adder.

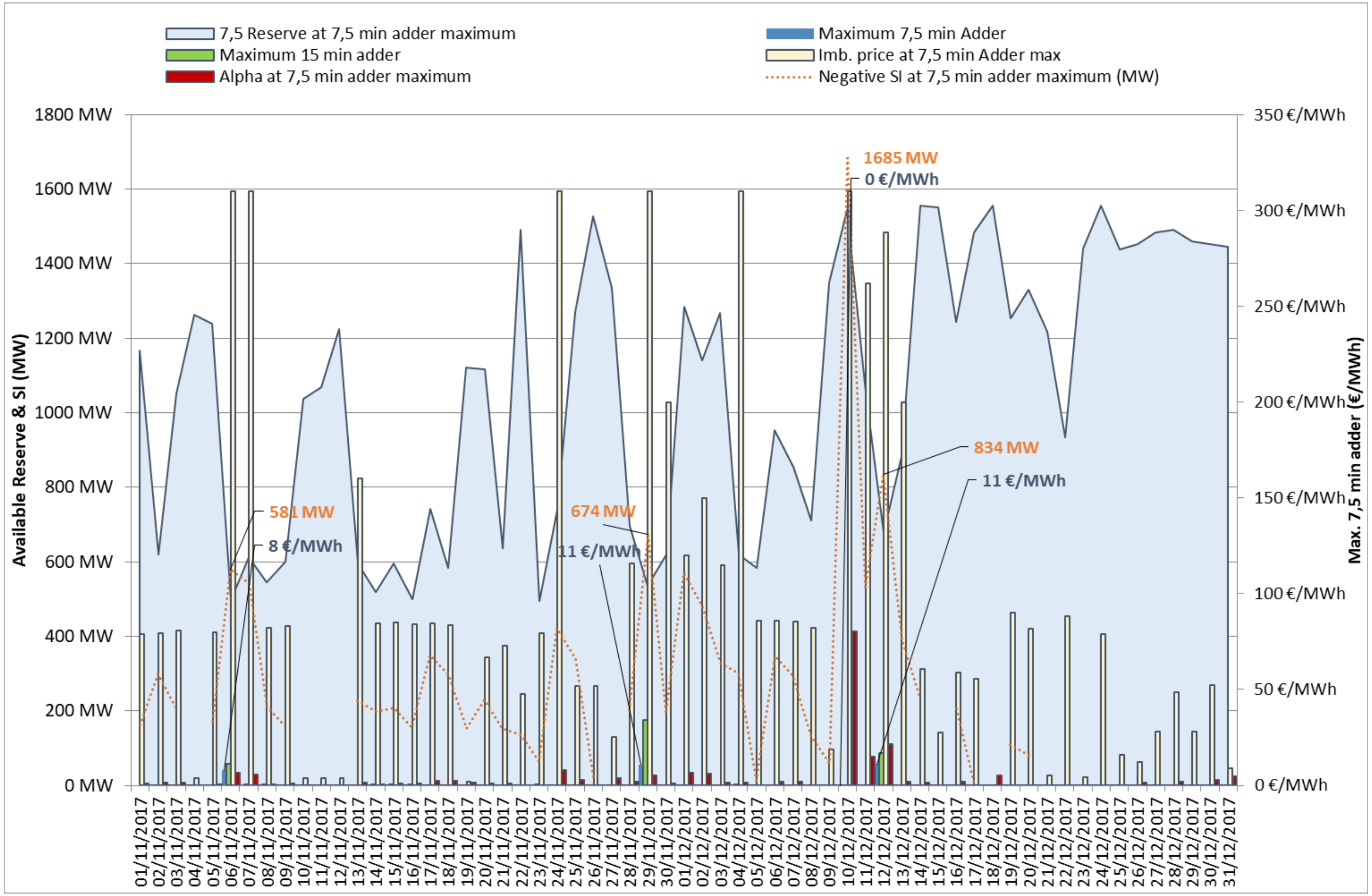


Figure 12: Base Case maximum daily 7,5 min adder for the November-December period

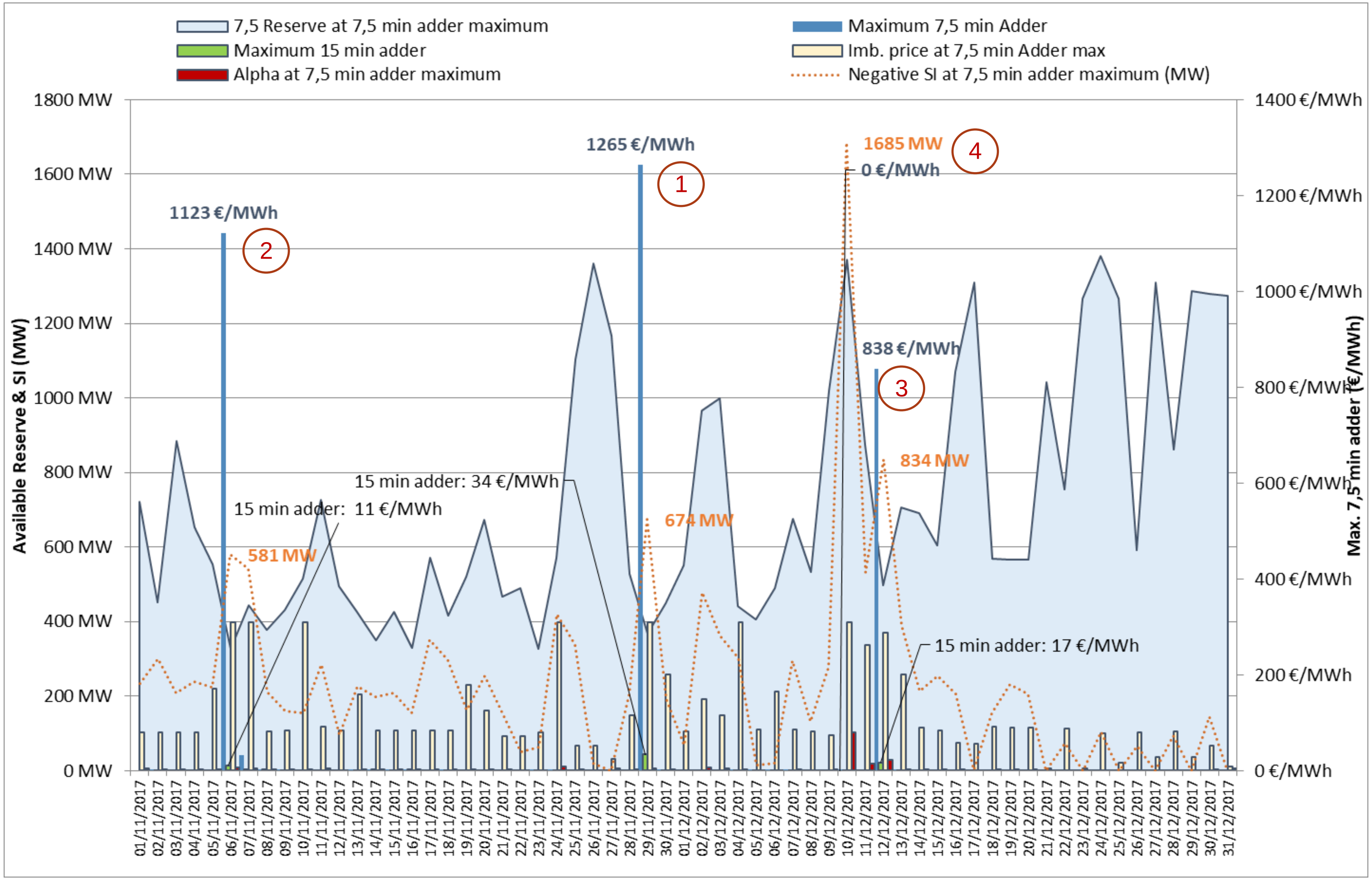


Figure 13: Sensitivity maximum daily 7,5 min adder for the November-December period

Figure 12 and Figure 13 contain a lot of elements that help in understanding the adder behavior:

- *Maximum 7,5min price adder (blue bars):* It provides the maximum 7,5min adder observed during a day. This value has to be read on the right vertical axis.
- *7,5min available reserve (blue surface)*: It provides the available 7,5min reserve at the moment of the day where the maximum 7,5min adder was reached. This value has to be read on the left vertical axis.
- *Negative System Imbalance (orange dashed line)*: It provides the negative 15min system imbalance ($Negative\ SI = (-1) * \min(SI, 0)$) at the moment of the day where the maximum 7,5min adder was reached. This value has to be read on the left vertical axis. To limit the complexity of the graph, moments where the zone was in a long position (SI > 0 MW) are set equal to 0 MW. This does not hamper the further interpretation of the graph. It is important to note that the 15min SI is used and shown on the graph. These are observed values. However, for the sake of the model, the SI at the 7,5min interval is assumed to be equal to 50% of the 15min SI. This also explains why sometimes the plotted SI has a higher value than the plotted reserve margin (blue surface). The latter is a 7,5min value, whereas the SI is a 15min value.
- *Maximum 15min adder (green bars)*: It provides the maximum 15min price adder. This value has to be read on the right vertical axis.
- *Imbalance Price (yellow bars):* This is represented by the light yellow bars. It provides the imbalance price at the moment of the day where the 7,5min adder was reached. This value has to be read on the right vertical axis.
- *Imbalance Alpha (red bars)*: This is represented by the red bars. It provides the imbalance alpha at the moment of the day where the 7,5min adder was reached. This value has to be read on the right vertical axis.

From Figure 12 and Figure 13 it can already be observed that a high system imbalance is not necessarily causing a high price adder and, vice versa, a high price adder is not necessarily linked to a high system imbalance. Bearing in mind the components of the price adder formula (cf. Equation 1), the available reserve appears to be the most determining factor.

In Figure 13, four particular situations are highlighted as these cases help in better understanding the actual functioning of the price adder. Those cases are further discussed in the next sections.

4.2.3.1 Case 1 – Price adder peak of 29 November 2017 at 18:00

The 2017 maximum simulated 7,5min and 15min price adders, respectively 1.265 €/MWh and 17 €/MWh, are reached on 29 November 2017 at 18:00. These price adder peaks emerge at a moment when the negative system imbalance is relatively important, 674 MW. There are no obvious reasons explaining this system imbalance as there were no power plant outages on that day. A possible explanation could be found in the wind and load forecast error fluctuations, as illustrated in Figure 14. The forecasts (errors) taken into account are the ones used by Elia and made available on Elia's website. Of course, every ARP is responsible for managing its own position and probably disposes of its own forecast. Therefore, the Elia forecast (errors) can only be indicative as an explanation for the system imbalance.

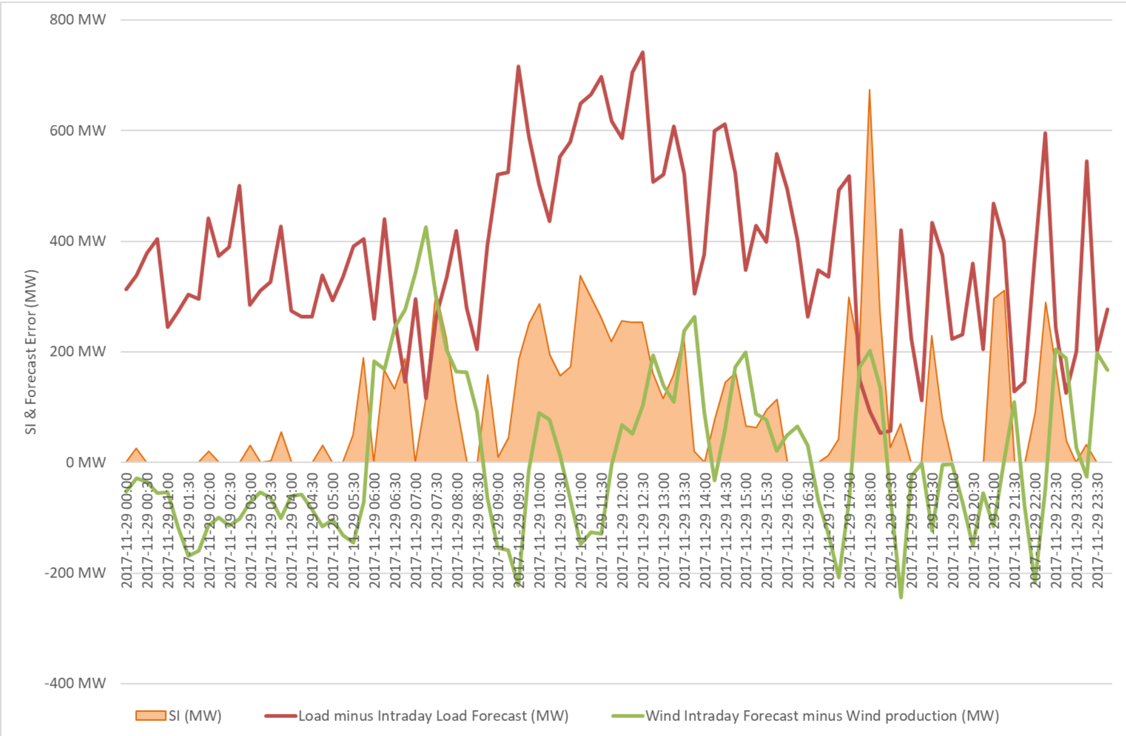


Figure 14: Negative System Imbalance, wind and load forecast errors on Nov 29, 2017

In Figure 15, for this particular day, the system imbalance, the price adders and the available reserve are shown:

- *7,5min adder (yellow and white bars):* The yellow bar provides the base case (i.e. with 50% of R3 non-CIPU included in the 7,5min available reserve) and the white bar provides the sensitivity case (i.e. with R3 Non CIPU excluded) and has to be read on the right hand vertical axis.
- *System Imbalance (orange dashed line):* The 15min system imbalance is provided. Its values have to be read on the left hand vertical axis.
- *15min available reserve (stacked colored surfaces)*: Each color corresponds to a different type of reserve:
    - Hydro pumped storage regulation capacity (light blue surface)
    - CIPU Coordinable margin (red surface)
    - R3 CIPU (purple (standard) and blue surfaces (flexible))
    - R3 Non CIPU (orange (standard) and dark blue surfaces (flexible))
    - ICH (green surface)
    - R2 (constant bottom blue surface)

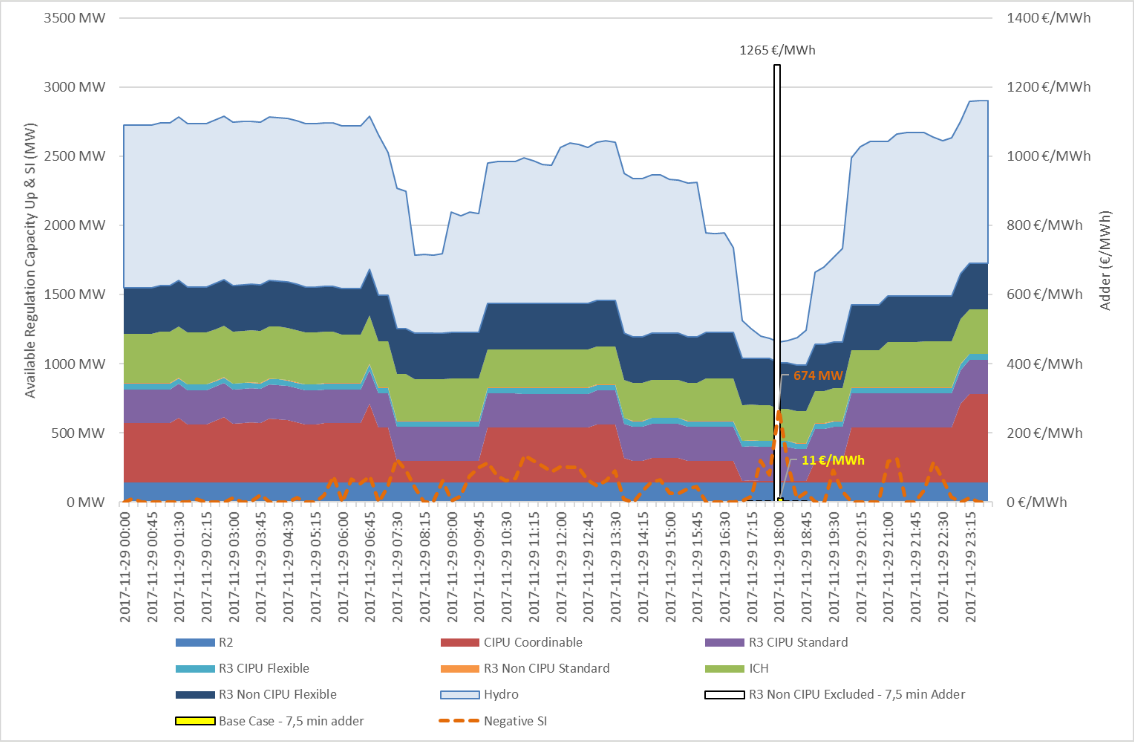


Figure 15 7,5 min adder, SI and Available Reserve, per type, on the 29 Nov 2017

It is interesting to notice that the price peak arises as a result of the combination of two effects:

- Increase in the system imbalance
- Decrease in available regulation capacity, in particular hydro pumped storage regulation capacity and CIPU Coordinable margin.

Table 7 gives the system imbalance and available reserve (per time horizon and case) on the 29 Nov 2017 at 18:00.

	15min available reserve	Base Case 7,5min reserve (incl. 50% R3 non-CIPU)	Sensitivity 7,5min reserve (excl. R3 non-CIPU)
R2	144 MW	144 MW	144 MW
CIPU Coordinable margin	**11 MW**	**5 MW**	**5 MW**
ICH	230 MW	0 MW	0 MW
R3 CIPU Standard	246 MW	123 MW	123 MW
R3 CIPU Flexible	40 MW	20 MW	20 MW
R3 Non CIPU Standard	**4 MW**	**2 MW**	**0 MW**
R3 Non CIPU Flexible	335 MW	168 MW	**0 MW**
Hydro pumped storage margin	148 MW	74 MW	**74 MW**
Negative SI	674 MW	337 MW[14]	337 MW
Remaining Reserve (Neg. SI – sum of reserves)	**484 MW**	**199 MW**	**30 MW**

Table 7: System Imbalance, available reserves and remaining reserve during 29 Nov 2017 18:00 adder peak. The numbers highlighted in red indicate low available reserve margins.

The previous table shows that in the base case there was 199MW of remaining reserve (negative system imbalance minus sum of available reserve) and 30MW in the sensitivity case with R3 Non CIPU excluded from the 7,5min reserve.

The reduction in CIPU Coordinable margin and hydro pumped storage margin comes from the fact that CIPU and hydro pumped storage units are nominated at PMax for the evening peak, in order to cover the high energy demand. As a consequence, there is no reserve margin left on these units for balancing. At that moment, there are only 79MW available of Hydro pumped storage and CIPU Coordinable margin combined.

[14] 50% of the Negative SI is accounted for in the computation of the 7,5 min adder, as explained in 2.3.2.

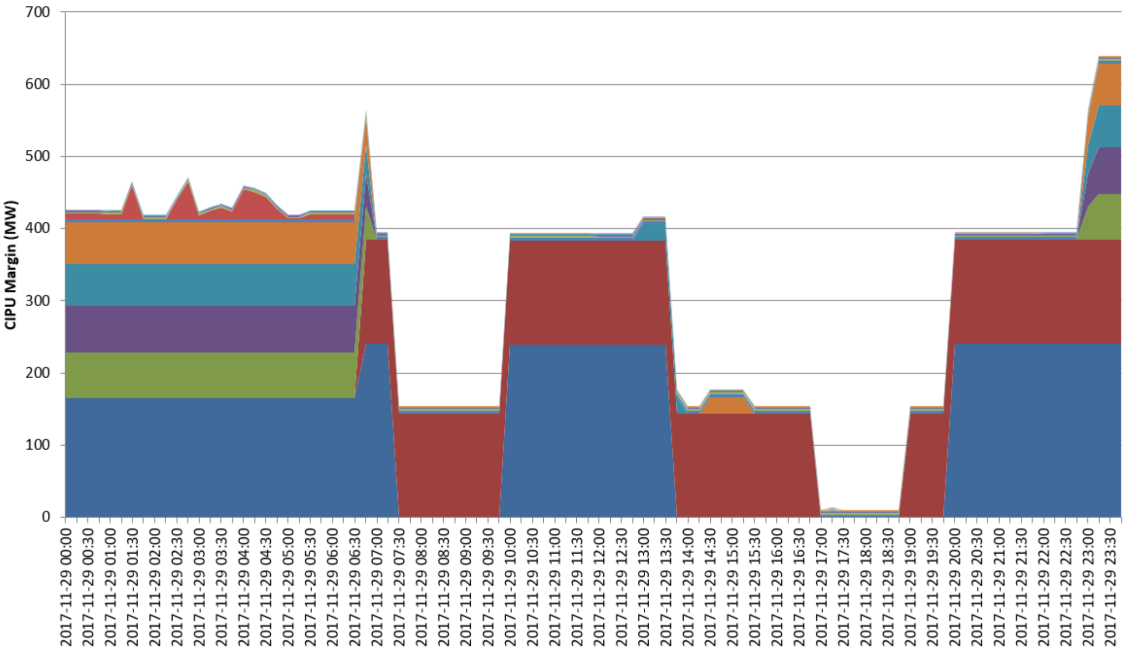


Figure 16: Available margin at largest CIPU Units. Hydro Pumped storage units are not included.

Furthermore, from Table 4 with the LOLP distributions we observe that the standard deviation for that season (winter) and period of the day was 147MW, thus 73,5MW on the 7,5min timeframe. In this case, a remaining reserve of 30MW yields a high LOLP (around 32%) and thus a high price adder, following Equation 2:

$$adder_{7,5min} = \frac{1}{2} * LOLP * (VOLL - MIP) = \frac{1}{2} * 31{,}66\% * (8.300 - 310) = 1.265\ €/MWh$$

In order to illustrate this further, Figure 17 plots the system imbalance probability density function (pdf), at 7,5min, for the winter season and hour block 19-22.

The LOLP is given by the surface below the pdf, starting at the available reserve. This figure shows that with the 30 MW remaining (in the sensitivity with R3 Non CIPU excluded from the 7,5min available reserve) there is a considerable amount of LOLP (32%), but with 199MW remaining (base case scenario) the LOLP becomes rather small (0,28%). This explains the difference between the considerable price adder peaks in the two scenarios from a mathematical perspective.

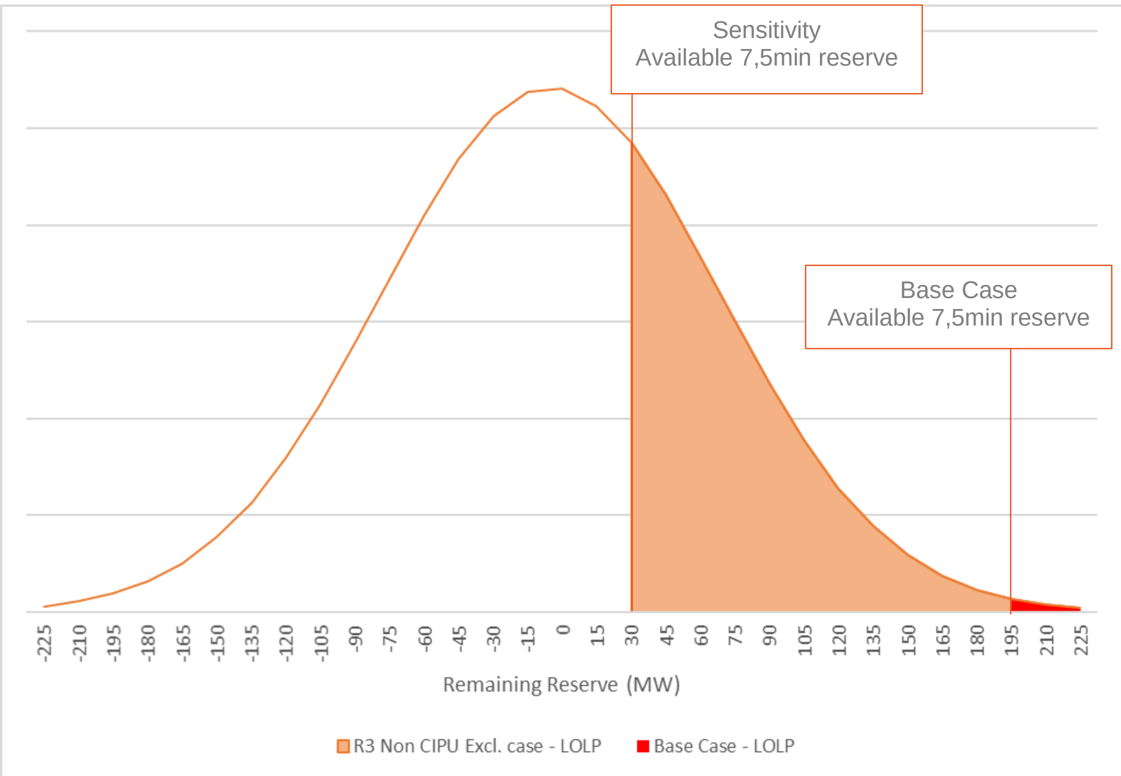


Figure 17: 7,5 min System Imbalance pdf and LOLP at 29 Nov 2018 18:00. LOLP is given by the colored surface. See Equation 1 and Section 2.3.2

4.2.3.2 Case 2 – Price adder peak of 06 November 2017 at 18:00

On 6 November 2017 at 18:00, the simulated 7,5min adder (sensitivity case without R3 Non CIPU) and the 15min price adder reach respectively 1.123 €/MWh. These peaks arise at a moment when the negative system imbalance is relatively important, i.e. 581 MW. Like in case 1, also at this moment there were no power plant outages. The system imbalance may again be due to a high load forecast error, as illustrated in Figure 18.

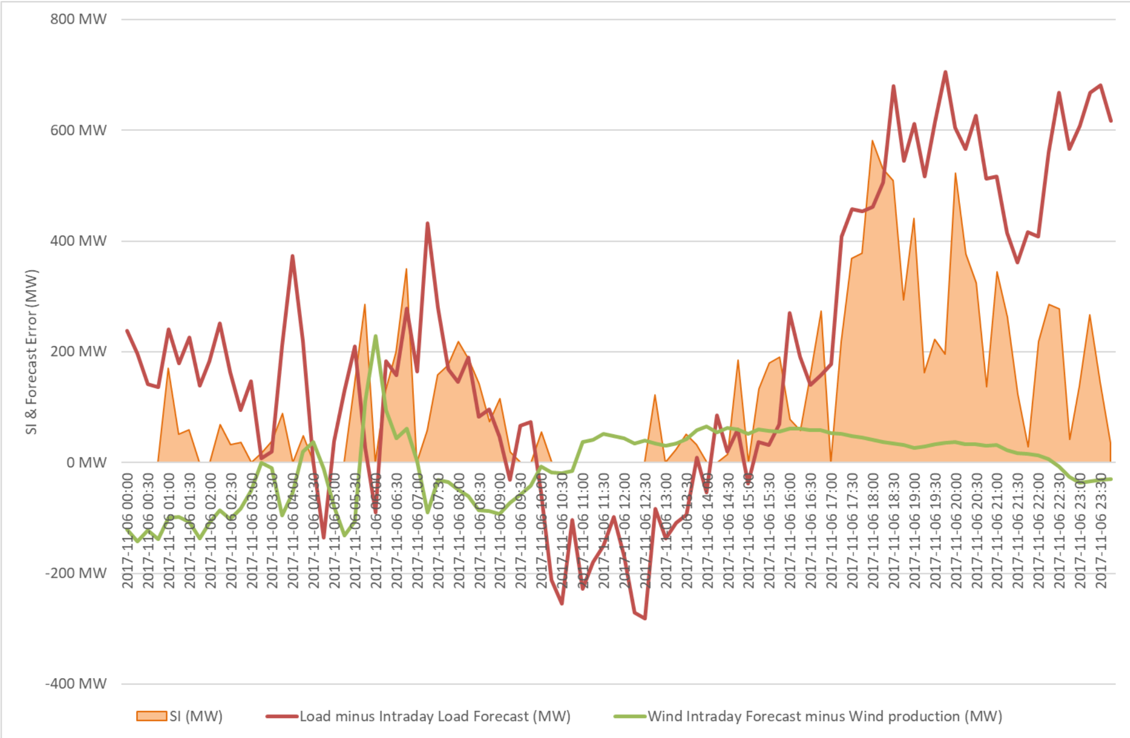


Figure 18: Negative System Imbalance, wind and load forecast errors on Nov 06, 2017

The chart shown in Figure 19, similarly to the one in Figure 15, provides a view on the system imbalance, remaining reserves and the price adders. It shows that there are three consecutive significant price adders (in the R3 Non CIPU excluded scenario), starting from 18:00. This is due to a situation of high SI and low reserve availability sustained during 3 quarter-hours.

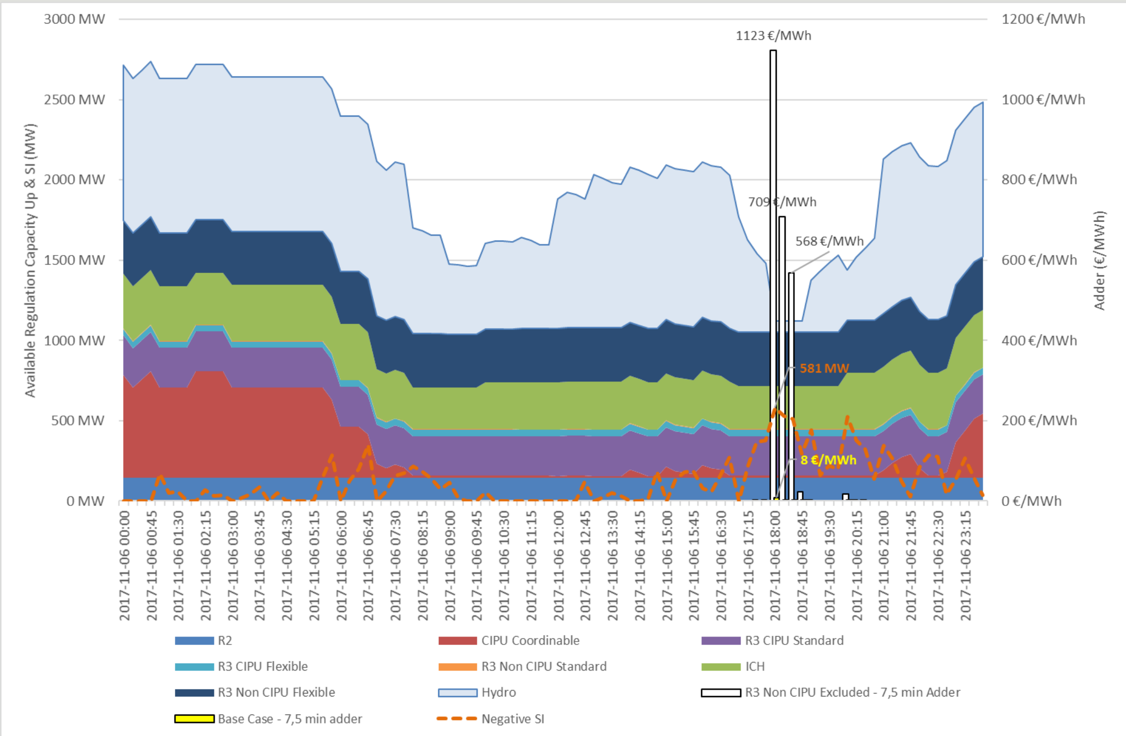


Figure 19: 7,5 min adder, SI and Available Reserve, per type, on Nov 06, 2017

Comparing the system imbalance with the available reserve margin shows that the remaining 7,5min reserve, in the sensitivity case excluding R3 Non CIPU, is merely 37MW. This explains the resulting high adder.

	15min available reserve	**Base Case 7,5min reserve (incl. 50% R3 non-CIPU)**	**Sensitivity 7,5min reserve (excl. R3 non-CIPU)**
R2	144 MW	144 MW	144 MW
CIPU Coordinable margin	13 MW	6 MW	6 MW
ICH	271 MW	0 MW	0 MW
R3 CIPU Standard	246 MW	123 MW	123 MW
R3 CIPU Flexible	40 MW	20 MW	20 MW
R3 Non CIPU Standard	4 MW	2 MW	0 MW
R3 Non CIPU Flexible	335 MW	168 MW	0 MW
Hydro pumped storage margin	69 MW	34 MW	34 MW
Negative SI	581 MW	290 MW	290 MW
Remaining Reserve (Neg. SI – sum of reserves)	**540 MW**	**207 MW**	**37 MW**

Table 8: System Imbalance, available reserves and remaining reserve on Nov 06, 2017 18:00 adder peak

The low availability of hydro pumped storage unit margin and CIPU Coordinable margin can be explained by the fact this happens at 18:00, during the evening peak, i.e. a moment at which the units are nominated at P_{Max} in order to cover the high demand. Only 40MW of Hydro pumped storage and CIPU coordinable margin combined is available at that moment.

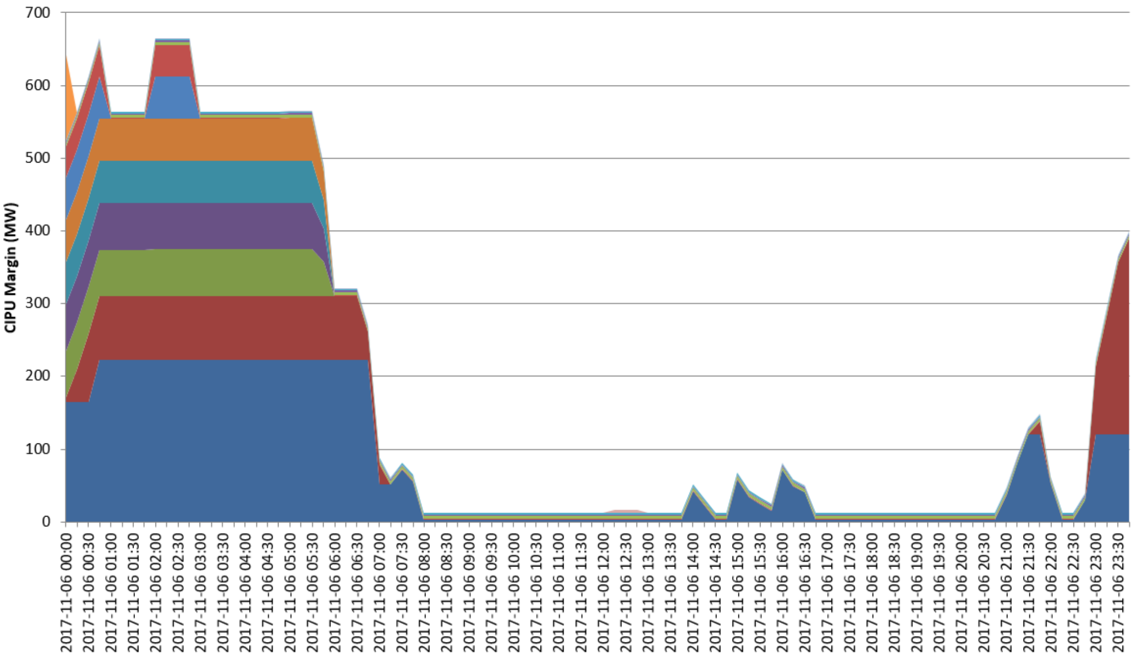


Figure 20: Available margin at largest CIPU Units. Hydro Pumped storage are not included.

Note that although the CIPU coordinable margin is close to zero during several other quarter hours of that day (cf.Figure 19), this does not trigger high price adders. This is explained by the fact that, during those hours, there remains a significant hydro pumped storage margin (cf. the light blue surface in Figure 19).

4.2.3.3 Case 3 – Price adder peak of 12 December 2017 at 09:00

On 12 December 2017 at 09:00, the simulated 7,5min adder (for the sensitivity without R3 Non CIPU) and the 15min price adders reach respectively 838 €/MWh and 11 €/MWh. This peak arises at a moment when the negative system imbalance is important, i.e. 834 MW. Like in the previous cases, there were no power plant outages on that day. The system imbalance may again be due to a high load forecast error, as illustrated in Figure 21.

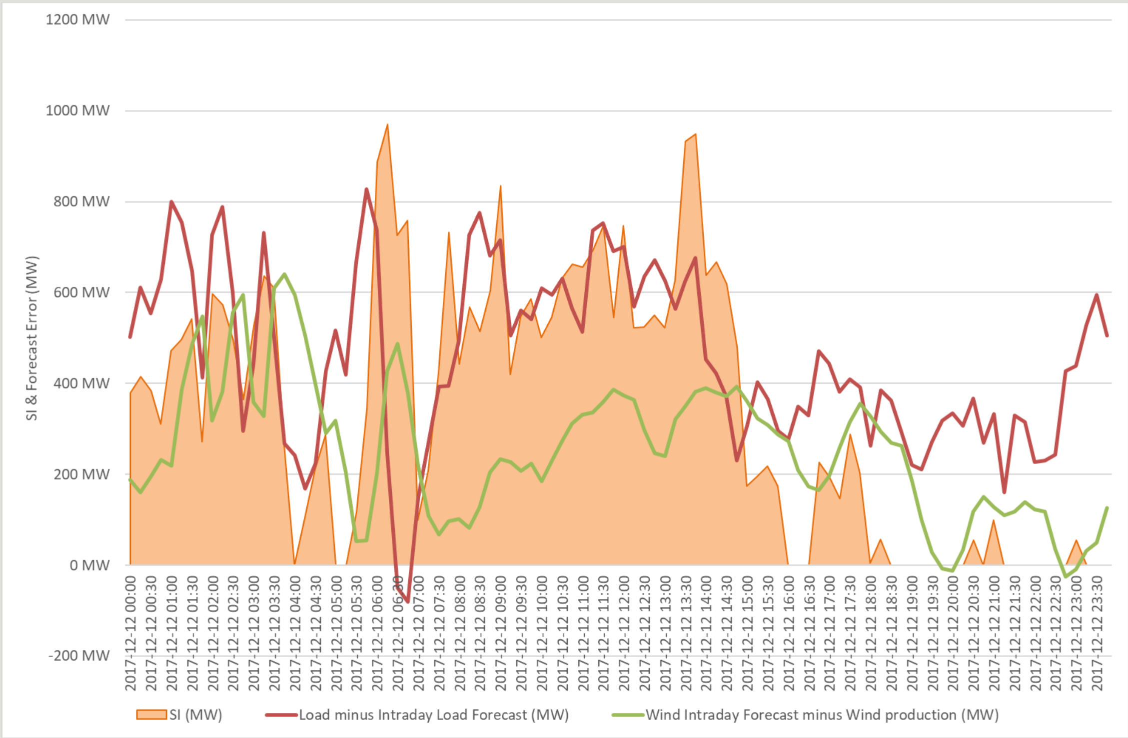


Figure 21: Negative System Imbalance, wind and load forecast errors on December 12, 2017

Figure 22 illustrates, similarly to Figure 15, the system imbalance, reserve margin and price adders for that day. It shows that a significantly negative system imbalance was reached, 970MW at 06:15, 834 MW at 09:00 and 949MW at 13:45. But only the peak of 09:00, combined with a low availability of reserve, triggered a significant 7,5min price adder. Note that there was also a 7,5min price adder (sensitivity with R3 non-CIPU excluded) reaching 81 €/MWh at 09:45 with a negative system imbalance of 586MW.

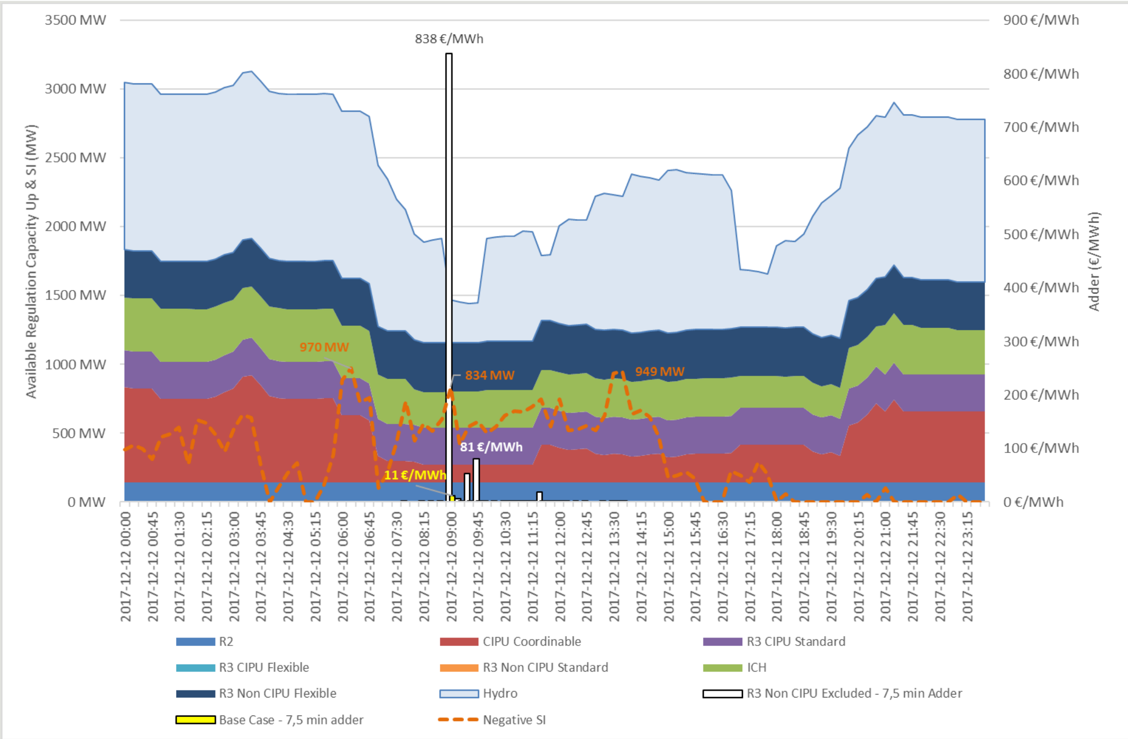


Figure 22: 7,5 min adder, SI and Available Reserve, per type, on the 12 December 2017

Table 9 compares the system imbalance with the available reserves. It shows that the remaining 7,5min reserve (sensitivity case excluding R3 Non CIPU), is 82MW. This explains the high price adder reached. The 7,5min base case and the 15min price adders are significantly lower as the remaining reserve is considerably higher.

	15min available reserve	**Base Case 7,5min reserve (incl. 50% R3 non-CIPU)**	**Sensitivity 7,5min reserve (excl. R3 non-CIPU)**
R2	144 MW	144 MW	144 MW
CIPU Coordinable margin	126 MW	63 MW	63 MW
ICH	262 MW	0 MW	0 MW
R3 CIPU Standard	269 MW	135 MW	135 MW
R3 CIPU Flexible	0 MW	0 MW	0 MW
R3 Non CIPU Standard	0 MW	0 MW	0 MW
R3 Non CIPU Flexible	356 MW	178 MW	0 MW
Hydro pumped storage margin	314 MW	157 MW	157 MW
Negative SI	834 MW	417 MW	417 MW
Remaining Reserve (Neg. SI – sum of reserves)	**638 MW**	**260 MW**	**82 MW**

Table 9: System Imbalance, available reserves and remaining reserve during December 12, 2017 09:00 adder peak

The low availability of hydro pumped storage unit margin and CIPU Coordinable margin may be explained by the fact that this happens at 09:00, during the morning peak, i.e. a moment at which the units are nominated close to P_{max} in order to cover the high demand. Note, however, that the situation is less critical than during the peaks of November 29, 2017 and November 06, 2017, because here there are 82MW of remaining reserve available (cf. Table 9). On the other dates, this number was 30MW and 37MW respectively (cf. Table 7 and Table 8).

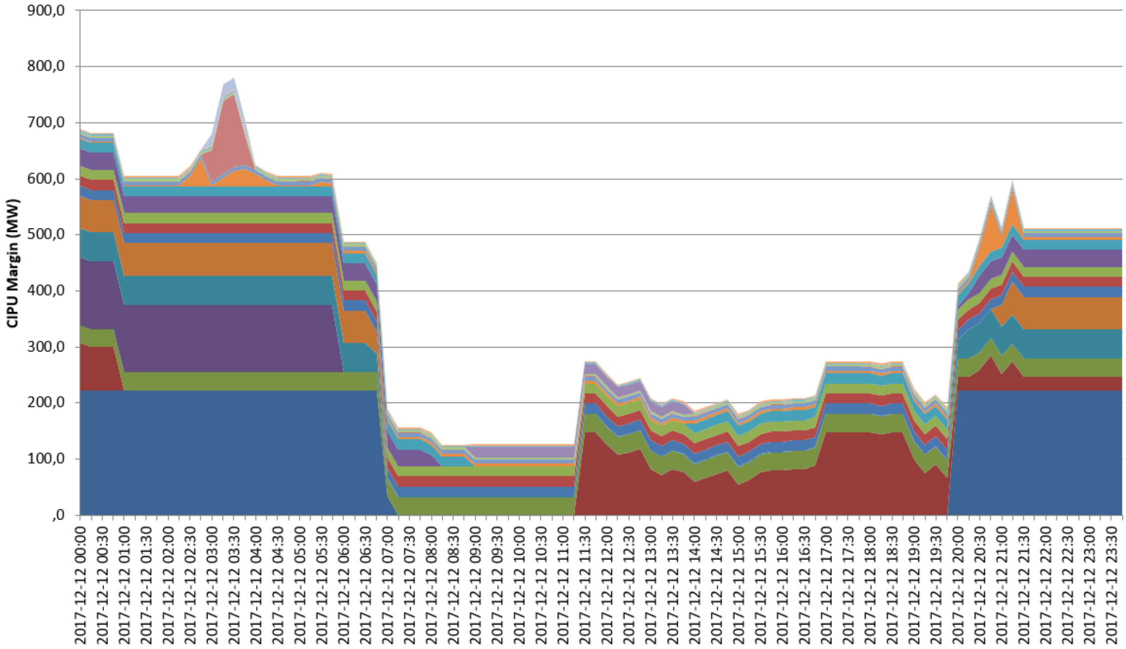


Figure 23: Available margin at largest CIPU Units. Hydro Pumped storage units are not included.

4.2.3.4 Case 4 – System imbalance peak of 10 December 2017 at 11:45

On December 10, 2017 there was no significant scarcity price adder reached, but the negative system imbalance reaches a 2017 maximum of 1.685MW at 11:45.

It is interesting to analyze this case in order to understand why such a high negative system imbalance did not trigger a high price adder.

As for the previous cases, there was no power plant outage on that date. On this date, a Sunday, the load forecast error was above 1 GW, which may explain the negative system imbalance peak, as shown in Figure 24.

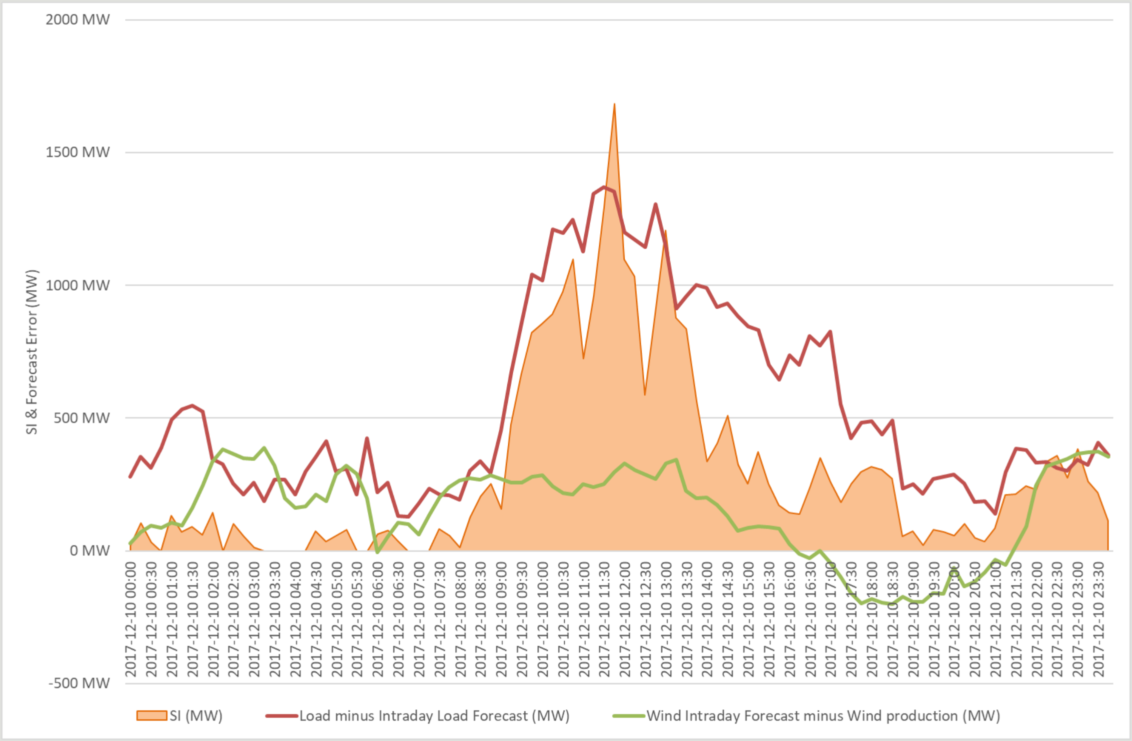


Figure 24: Negative System Imbalance, wind and load forecast errors on Dec 10, 2017

Figure 25 illustrates, similarly to Figure 15, the system imbalance, reserve margin and price adders for that day. It shows that there was plenty of reserve left at the moment that the negative system imbalance reached its maximum. The chart also shows a less volatile available reserve on this Sunday than on the previous examples, potentially explained by the fact that this is a weekend day with a more modest demand profile.

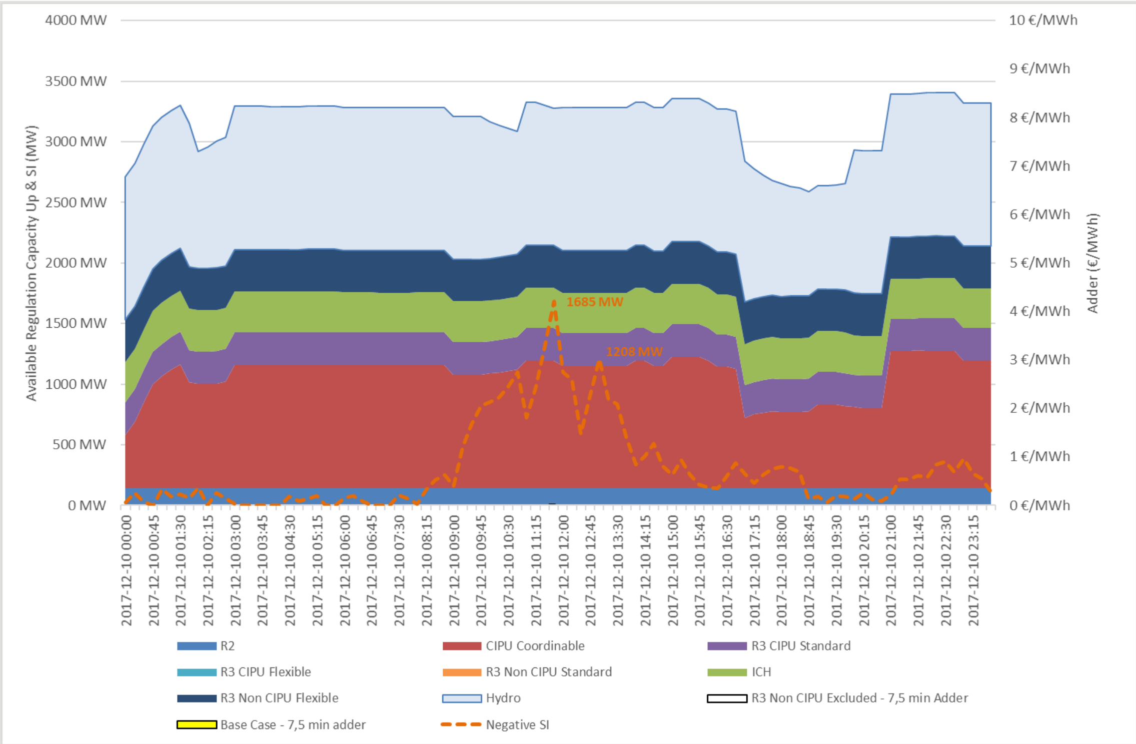


Figure 25: 7,5 min adder, SI and Available Reserve, per type, on December 12, 2017

Table 10 compares the system imbalance with the available reserves. It shows that the remaining 7,5min reserve (sensitivity case excluding R3 Non CIPU), amounts to 527MW. This is significantly higher than in the previously discussed cases and it explains why no significant price adder was triggered at that moment.

	15 min reserve	**Base Case 7,5 min reserve**	**R3 Non CIPU Excl. 7,5 min reserve**
R2	144 MW	144 MW	144 MW
CIPU Coordinable margin	1052 MW	526 MW	526 MW
ICH	334 MW	0 MW	0 MW
R3 CIPU Standard	269 MW	135 MW	135 MW
R3 CIPU Flexible	0 MW	0 MW	0 MW
R3 Non CIPU Standard	0 MW	0 MW	0 MW
R3 Non CIPU Flexible	347 MW	174 MW	0 MW
Hydro pumped storage margin	1131 MW	566 MW	566 MW
Negative SI	1685 MW	843 MW	843 MW
Remaining Reserve (Neg. SI – sum of reserves)	**1591 MW**	**701 MW**	**527 MW**

Table 10: System Imbalance, available reserves and remaining reserve during 10 December 2017 11:45 adder peak

4.2.4 Summary of the main observations on the 2017 price adders

The above 2017 results generally indicate that there have been very few quarter hours during which price adders were significantly different from zero. This can be interpreted as 2017 being a very modest year in terms of scarcity. If this is the case then the model provides acceptable results as it should not trigger price adders when there is no need. However, the results do not suggest an extra revenue stream for covering investment costs in 2017. Price (adder) spikes remain very rare.

Of course, the results may also be driven by the setup of the model and several of the hypotheses made. It goes beyond the scope of this study, but it may be useful to investigate whether alternative assumptions could be justified and if that would result in other conclusions.

Despite the modest 2017 outcome in terms of scarcity price adders, the exercise has been useful. The results, and in particular the analysis of the four more extreme cases, reveal that the model behaves as it is expected to behave. Higher price adders are indeed reached in situations when margins get tighter and situations with large imbalances do not result in high price adders if, at the same time, reserves are not becoming scarce. Although the number of data points may be too limited to draw robust conclusions, and despite the fact that model is particularly tuned to balancing reserves and margins, the observed significant price adders occurred during (mainly evening) peak demand moments. This may suggest a link with moments also relevant for adequacy.

4.3 Settlement simulation results

The price adders obtained in the simulation have been presented in section 4.2. In order to evaluate the impact of these price adders for different market actors, settlement simulations have been performed on the different markets depicted by the model, namely a real-time energy market and a real-time available reserve market, cf. section 2.2.2.1.

In these settlement simulations, there is an assessment of the impact of the price adder in the cash flow. This implies that the settlement figures are not provided as an absolute value, but rather as the difference between a situation with price adders and a situation without price adders.

In section 2.2.1 the real-time energy price calculation was presented. The real-time energy price equation defined in section 2.2.1 involves the marginal incremental cost and the price adders:

$$\lambda = MC(\sum_g P_g) + \frac{T_1}{T_1 + T_2}\left(VOLL - \widehat{MC}\left(\sum\nolimits_g p_{g,t}\right)\right) \cdot LOLP_{T_1}(R_{T_1}) +$$

$$\frac{T_2}{T_1 + T_2}\left(VOLL - \widehat{MC}\left(\sum\nolimits_g p_{g,t}\right)\right) \cdot LOLP_{T_1+T_2}(R_{T_1+T_2})$$

This equation can be further simplified using the adders defined in section 4.2.1:

$$\lambda = MC(\sum_g P_g) + adder_{7,5\,min} + \ adder_{15\,min}$$

Thus, for the real-time energy price the delta between the situations with and without a price adder is:

$$\Delta_\lambda = adder_{7,5\,min} + adder_{15\,min}$$

Equation 14: Delta in real-time energy price due to the introduction of a scarcity price

The price for real-time available reserve was also developed in Section 2.2.2. A similar expansion as for the real-time energy price can be done for the prices of real-time available reserve (for fast and slow responding reserves respectively):

$$\lambda RRT_t^F = \frac{T_1}{T_1+T_2}\left(VOLL - \widehat{MC}\left(\sum\nolimits_g p_{g,t}\right)\right) \cdot LOLP_{T_1}(R_{T_1})$$

$$+ \frac{T_2}{T_1+T_2}\left(VOLL - \widehat{MC}\left(\sum\nolimits_g p_{g,t}\right)\right) \cdot LOLP_{T_1+T_2}(R_{T_1+T_2})$$

$$\lambda RRT_t^S = \frac{T_2}{T_1+T_2}\left(VOLL - \widehat{MC}\left(\sum\nolimits_g p_{g,t}\right)\right) \cdot LOLP_{T_1+T_2}(R_{T_1+T_2})$$

By replacing with the adders defined in section 4.2.1:

$$\lambda RRT_t^F = adder_{7,5\,min} + adder_{15\,min}$$

Equation 15: Fast reserve availability price

$$\lambda RRT_t^S = adder_{15\,min}$$

Equation 16: Slow reserve availability price

Equation 15 and Equation 16 imply that fast, i.e. 7,5min, reserves are settled at the sum of the 7,5min and the 15min price adders and that slow, i.e. 15min, reserves, are settled at the 15min adder.

In the simulations, the difference between the available reserve on day ahead is compared to the available reserve on real-time, distinguishing 7,5min reserve and 15min reserve (as defined in 2.3.3). This difference between real-time and intraday reserve is then valorized following Equation 15 and Equation 16.

Summarizing, the impact of the scarcity price mechanism in settlement is as follows:

- *Real-time energy price* is incremented by $adder_{7,5\,min} + adder_{15\,min}$
- *Day-Ahead versus Real-Time difference in fast (7,5min) reserve availability* is remunerated at $adder_{7,5\,min} + adder_{15\,min}$
- *Day-Ahead versus Real-Time difference in slow (15min) reserve availability* is remunerated at $adder_{15\,min}$

4.3.1 Producer Settlement

In Section 2.3.4.1 the approach for calculating the available reserve in real time as well as the real-time energy for producers was explained.

For this report, a subset of power plants is selected. This set is representative of different production technologies and contains both units providing reserve and units not participating in the reserve market. For this subset of units the approach defined in section 2.3.4.1, and in particular Equation 10 and Equation 11, are used to calculate the real-time energy and real-time reserve availability. After having evaluated the available reserve, the price adders, as calculated for section 4.2, are applied for valorizing the impact of the price adders in the real-time energy and real-time reserve availability settlement.

The impact on settlement for the considered power plants is summarized in Table 11 (base case) and Table 12 (sensitivity).

Power Plant	Delta in real-time energy	Delta in 7,5min reserve Settlement	Delta in 15min reserve Settlement
Plant A	-135 €	€	€
Plant B	124 €	€	€
Plant C	1.707 €	-365 €	-626 €
Plant D	65 €	21 €	26 €
Plant E	54 €	30 €	47 €
Plant F	106 €	€	€
Plant G	59 €	137 €	202 €
Plant H	-49 €	25 €	34 €
Plant I	189 €	€	€

*Table 11: Base Case. Producer settlement for 2017. *NA stands for not applicable, these power plants do not participate in the reserve market*

Power Plant	Delta in real-time energy	Delta in 7,5min reserve settlement	Delta in 15min reserve settlement
Plant A	-4.437 €	NA*	NA*
Plant B	7.782 €	-7 €	€
Plant C	36.349 €	-3.793 €	-626 €
Plant D	7.805 €	738 €	26 €
Plant E	7.796 €	874 €	47 €
Plant F	6.664 €	-4 €	€
Plant G	659 €	NA*	NA*
Plant H	-2.820 €	1.483 €	34 €
Plant I	8.450 €	11 €	€

*Table 12: Sensitivity (R3 Non CIPU Excluded). Producer settlement for 2017. *NA stands for not applicable, these power plants do not participate in the reserve market*

The results in Table 11 and Table 12 show a very limited effect of the price adder in 2017 settlement of the available reserve, with the biggest difference between a situation with no price adder being -3.793€ in the sensitivity on 7,5min available reserves. The impact of the adder in balancing (real-time energy) settlement is higher than the impact in the settlement of reserves. Nevertheless, the highest observed amount of 18.850€ (in the sensitivity) remains very small when compared to the actual sales revenues from a power plant.

4.3.2 R2 Providers

The case of R2 providers is particular as these providers are delivering exclusively fast reserve (7,5min). The R2 is currently provided by production units. In this case Equation 11 can be used as a basis for calculating the available 7,5min reserve in real time. The available day-ahead R2 volume is taken from the R2 day-ahead nominations.

Note that, in the simulations, the volume of R2 is capped by the contracted volume. This may be a conservative choice, assuming that the producer may not be able to provide more fast reserve than the volume contracted.

In Table 13 and Table 14 the results for the base case and the sensitivity are respectively provided. The last column shows the total effect of the price adders in the settlement of the R2 provider.

Delta in 7,5min reserve settlement	Delta in real-time energy	Total
-2.208 €	**3.785 €**	**1.577 €**

Table 13: R2 Provider Settlement Impact. Base Case Scenario for 2017

Delta in 7,5min reserve settlement	Delta in real-time energy	Total
-123.735 €	**175.221 €**	**51.487 €**

Table 14: R2 Provider Settlement Impact. R3 Non CIPU Excluded Scenario for 2017

It is worth highlighting the explanation provided in section in 2.3.4.1 about the remuneration of reserve activation. In section 2.3.4.1 it was explained that reserve activation is not explicitly remunerated, as it is considered to be part of extra energy sold on the real-time energy market. On the other hand, a reserve activation might reduce the available volume of reserve and thus reduce the revenue from reserve availability. The results in Table 13 and Table 14 show this effect. The activation of R2 reduces the revenues from the real-time reserve availability, while at the same time, the revenue from real-time energy is increased.

The overall impact of the scarcity price mechanism in R2 is -123.735€ in terms of fast, 7,5min, reserve remuneration, and 175.221€ in terms of extra real-time energy market income. These figures sum up to a net effect of a hypothetical scarcity price mechanism in 2017 of 51.487€

In any case, the most significant impact, of 51.487€, is far below the remuneration of R2 capacity. In the “Ancillary Services: Volumes & Prices” page on the Elia website[15] the price for R2 capacity in 2017 is on 13 €/MW/h on average. This gives a total yearly figure for 144MW of 17 M€. Of course, the analysis presented here does not account for any back-propagation of the adder to the day-ahead reserve and energy market.

4.3.3 ICH Settlement

In Section 2.3.4.2, the settlement approach for ICH was explained. The impact of the price adders for an ICH provider are in the real-time energy revenues and in the real-time reserve availability revenues. As depicted in Figure 3, an ICH-provider consuming more energy in real time than announced in day-ahead will be penalized in the real-time energy market for this extra consumed energy, while at the same time the ICH will get an extra remuneration in the reserve market by making more reserve available. The opposite situation was shown in Figure 4, where the lower consumption in real-time compared to day ahead will bring extra remuneration from the real-time energy market while at the same time it will reduce the available reserve and thus the real-time reserve remuneration.

The approach of section 2.3.4.2 has been followed, by taking ICH data from 2017 (nominations, shedding limit and actual consumption) and by applying the price adders as calculated for section 4.2.

A particularity of ICH in these simulations is that ICH is considered as a slow, 15min, reserve (as explained in section 2.3.3). As such, ICH real-time availability will be remunerated following Equation 16, i.e. at the 15min price adder. On the other hand, the delta in real-time energy settlement will be determined following Equation 14, i.e. as the sum of the 15min and 7,5min price adders.

The results from the simulations are shown in Table 15 and Table 16, for the base case

[15] See www.elia.be/en/suppliers/purchasing-categories/energy-purchases/Ancillary-services/Ancillary-Services-Volumes-Prices

and sensitivity respectively. As ICH is a slow reserve, the real-time reserve availability is remunerated at the 15min price adder.

Delta in 15min reserve settlement	Delta in real-time energy
-1.187 €	1.751 €

Table 15: ICH remuneration delta. Base Case scenario for 2017

Delta in 15min reserve settlement	Delta in real-time energy
-1.187 €	68.664 €

Table 16: ICH remuneration delta. Sensitivity scenario for 2017

These results show that ICH-providers have reduced their consumption at moments when the price adder is high. Consequently, they are penalized on the reserve availability market as less load is available for shedding, while on the real-time energy market they benefit from an extra remuneration as it is assumed that they can resell the non-consumed energy. The fact that the real-time reserve availability delta remuneration is calculated on basis of the 15min adder, while the real-time energy delta remuneration is calculated on basis of the sum 15min and 7,5min price adder (the former being on average close to zero, the latter being more pronounced) explains why the impact in real-time energy is more important. In any case, these figures, including the ones obtained in the sensitivity, are very small when compared to the amounts settled by ICH providers in the energy market.

The global effect of the adder on ICH provider settlement is very limited in the 15min real-time reserve settlement, amounting to -1.187€. On the real-time energy market, the total effect accounts for 68.664 € in the sensitivity. Nevertheless, this figure is still very small compared to the total amounts in play in the energy and reserve settlement of ICH. As shown in Elia “Ancillary Services: Volumes & Prices” page[16], the price for ICH reserve in 2017 was cleared at 1,81 €/MW/h, for a volume of 200MW, which makes a total of 3,1M€ for the settlement of ICH capacity in 2017. Again, these calculations do not account for any back-propagation of the adders to day-ahead energy and reserve markets.

4.3.4 Grid user settlement

In section 2.3.4.3, the settlement approach for grid users that are not providing reserve through ICH was presented. Given that these actors do not participate in the reserve market, the impact of the adder is limited only to the real-time energy market.

As shown in Figure 5, if a grid user consumes less than announced in day-ahead, then the non-consumed energy can be valorized at the real-time energy price. In the opposite

[16] http://www.elia.be/en/suppliers/purchasing-categories/energy-purchases/Ancillary-services/Ancillary-Services-Volumes-Prices

case, if a grid user consumes more than announced in the day-ahead, then the extra energy will have to be sourced at the real-time energy price.

For the simulations of the impact of the price adder for grid user settlement, three grid users with a high consumption are selected (i.e. all above 1,5 TWh/year). In Table 17 and Table 18 the results of the simulations are shown, for the base case and sensitivity respectively.

Grid User	Delta in real-time energy
Grid User A	355 €
Grid User B	401 €
Grid User C	106 €

Table 17: Grid user settlement simulations. Base case

Grid User	Delta in real-time energy
Grid User A	9.742 €
Grid User B	13.220 €
Grid User C	-2.596 €

Table 18: Grid user settlement simulations. Sensitivity

In the base case, all selected grid users benefit from the price adder, with a maximum of 401€. This means that these grid users lowered their consumptions at moments when the price adders were significant.

In the sensitivity case, there is one grid user for which the effect becomes negative. It is interesting given that in the base case the situation was the opposite. This is due to the fact that, with the more extreme peaks in the sensitivity, any increment of consumption at moments when the adders are significant will have a severe impact.

In any case, the results are very modest. Even in the sensitivity case, the effect of the price adder is only limited to 13.220€ in the best case and to -2.596€ in the worst case.

4.3.5 Summary of the observations related to the settlement calculations

When interpreting the settlement results, it is important to keep in mind the observations made in section 2.3 related to the mapping of the model to the Belgian market design and (sometimes strong) assumptions that have been taken (e.g. with respect to the existence of a real-time market for available reserves).

As in 2017 the simulated amount of quarter hours with a scarcity price adder is very limited (cf. section4.2) and generally the level of the adder is very low (except for a limited number of quarter hours in the 7,5min sensitivity case), the impact on the settlement on the assumed markets is very limited for all considered roles. As a consequence, also any investment signal triggered by scarcity price adders in 2017 is very limited under the considered model assumptions and calibration. Note that these simulations have been done under the assumption that there is no back-propagation of the price adders to the forward time horizon.

5 Conclusions and lessons learned

This study on scarcity pricing, conducted in the context of a discretionary incentive for Elia for 2018, builds further on earlier work done by CREG and UCL CORE. It can be considered as a learning step in better understanding how scarcity pricing models could be applied in Belgium.

The main contributions of this study are threefold:

(1) the translation or mapping of the currently studied scarcity pricing model, i.e. the model used by UCL CORE and inspired on the Texas ERCOT model, to the Belgian context in its best possible way,
(2) the definition of a concrete Belgian dataset suitable for the purpose of this model and
(3) the simulation of the model resulting in scarcity price adders and settlement calculation for the entire year of 2017.
(4) these contributions meet the objectives identified at the start of the study.

The main learnings of this study can be summarized as follows:

- The applied scarcity pricing model results for 2017 are rather modest in terms of price adders. Over the entire year of 2017, only a handful of quarter hours have a price adder significantly different from zero. This significantly reduces its effect in terms of providing a revenue stream to capacity providers based on this price adder.
- The level of the price adder greatly depends on the time frame considered, i.e. 15min or 7,5min, and on the reserves assumed to be available within those time frames. Whereas the 15min price adder tops at 35,59 €/MWh, the 7,5min price adder reaches 11,13 €/MWh and 1.264,94 €/MWh in respectively the base case and sensitivity case. The higher price adders obtained in the latter case are explained by the reduced level of available reserves by not considering 50% of the R3 non-CIPU reserves, which triggers a higher loss of load probability according to the model.
- A detailed analysis of observed, more extreme cases reveals that the expected model dynamic is observed, i.e. high price adders are linked to tight situations with little remaining reserve margins. Having a high system imbalance is not a sufficient condition for having high price adders.
- With regards to the 'settlement simulations', it is important to bear in mind the strong hypotheses taken to model the settlement impact, particularly the assumption on the existence of a real-time reserve market. The latter is crucial (and today not fulfilled in reality), irrespective of the size of the financial impact. The calculated impact of the price adders on the settlement of producers and consumers is very limited due to the overall modest price adders calculated for 2017.

Although the study illustrated that the dynamic of the scarcity pricing model can be achieved under the stated assumptions, it also triggers some questions which may require further research if scarcity pricing is ever to be implemented in Belgium.

A first set of the questions relate to the (technical) setup of the model for which studying alternative hypotheses may potentially provide a clearer view on why in 2017 the number of hours with a significant scarcity price adder was very limited. Part of the answer could of course remain in 2017 being really a year with very few situations with increased scarcity concerns.

A second, more fundamental set of questions relate to the mapping of the Belgian (and European) market design to the market design setting assumed (and required?) by the scarcity pricing model. As briefly mentioned in the introduction, the way markets are organized in Belgium and how this will further evolve over the next years and the strongly interconnected nature of the Belgian market across all time frames, may trigger important reflections on how to guarantee that the application of such a model results in the intended revenue streams towards the correct market roles while ensuring compatibility with the overall design.