Public consultation on the methodology, hypotheses and data sources for the dimensioning of the volumes of strategic reserve needed for winter 2018-2019

Consultation period:

From 24/04/2017 to 22/05/2017

Contents

1 What is new in the proposed methodology, hypotheses and data sources for winter 2018-19 compared to the analysis for winter 2017-18

Since 2014, a strategic reserve mechanism has been in place to strengthen the electricity security of supply of Belgium during the winter period. This mechanism entails new tasks and responsibilities for Elia System Operator (hereafter 'Elia'). One of these is to determine the need for the strategic reserve by means of a probabilistic assessment. This report provides an overview of the methodology, hypotheses and data sources as part of the stakeholder consultation process prior to the assessment for the winter period 2018-19 that Elia is required to conduct.

Elia is committed to continuously develop both the modelling methodology and the underlying data assumptions in order to increase the accuracy of its adequacy assessments. Below we include an overview of the new methodological improvements to be implemented in the assessment for winter 2018-19, compared to the assessment performed for winter 2017-18:

NTC modelling

Simulated random forced outages of HVDCs will be incorporated in the modelling in addition to forced outages of thermal units. HVDC outages are useful to incorporate the availability of these interconnectors as a mean to cope with adequacy problems. This new methodological improvement will incorporate in all the simulations the effect of the availability of HVDC lines on the system adequacy – see chapter 5.4.2

Flow-Based modelling

- A revision of the selection process and number of typical days and their corresponding flow-based domains from the flow-based operational environment will be done. Data comprising observations of the previous two winters (2015-16 and 2016-17) will be analysed for this purpose. Also a special focus is on ensuring coherence with ongoing national and regional adequacy assessments including flow-based methods – see chapter 5.5.2

- New way of correlating the flow-based domains with climatic data. Last year three typical domains where considered and their correlation to hourly situations was driven only by the level of wind infeed in DE. This year a more systematic approach will be followed linking specific combinations of climate conditions for wind, PV and load with the representative flow-based domains to be considered in the simulations – see chapter 5.5.2

Climatic database

A new climatic database of wind, PV and temperature time series procured in the framework of ENTSO-E will be used to align and ensure coherence with ongoing regional and Pan-European adequacy assessments – see chapter 5.1.2

Thermal Sensitivity of Load

A new way of incorporating the temperature sensitivity of the load will be used. Instead of a linear relationship between temperature and load, a cubical relationship is used which allows to capture in a systematic way effects like saturation, while preserving the level of accuracy of the linear method previously used – see chapter 5.2.2.2 and 5.2.2.3

Market Response

Key market stakeholders have been engaged in a continuous interaction process to design the most adequate methodology to determine the volumes of Market Response in Belgium. The methodology was designed based on interactions with stakeholders, over the course of four workshops and bilateral interviews – see chapter 5.6

2 Introduction

This public consultation is held in the context of the yearly process of the volume determination of strategic reserve, as described in the Article 7bis of the Law of 29 April 1999 concerning the organisation of the electricity market ('Electricity Act'). The analysis by Elia concerns the need for the winter 2018-19 and an indication for the winters 2019-20 and 2020-21.

Elia wants to provide the market parties a full understanding of the methodology and data for the calculation of the necessary volume of strategic reserve. The market parties will be able to submit their comments and suggestions through various interactions.

A first interaction concerns this document, which provides an overview of the methodology and references to the main data sources to be used for the calculation of the necessary volume of strategic reserve. For this consultation no specific questions are provided, but these can be formulated in any way desired through comments or suggestions on the provided consultation documents.

This document is divided in three main parts:

- The first provides an overview of the legal framework (Chapter 3);
- The second section describes the proposed methodology (Chapter 4);
- The last part provides an overview of the main hypotheses and data sources that are proposed to be used for the analysis (Chapter 5).

Later this year, when the various data sets will be available to Elia (between mid-August to mid-September), a second interaction will be organized with the market parties on the precise data that will be used for the calculations. An overview of the data categories which will be used is contained in this document and it is based on the data used in the previous report for winter 2017-18 with the pertinent additions.

Comments relating to changes in the law or other issues that are not within the competence of Elia are therefore not part of the consultations organized by Elia.

It is important to note that all comments received will be published at the end of the consultation, unless confidentiality constraints are explicitly communicated towards Elia.

2.1 Other documents where the methodologies are described

The methodology presented in this document is based on the method used in the report of November 2016 for the volume determination of strategic reserve for winter 2017-18 [11]. A similar method was also used to answer the request of the Minister of Energy on the assessment of the need for adequacy and flexibility of the electricity system for the 2017-27 horizon. This study is publicly available in French [15] and Dutch [16].

2.2 Timing

This document is published on Elia's website from April 24, 2017 onwards. The different reactions from stakeholders should be sent via email to the following address: usersgroup@elia.be.

Stakeholders have a period of four weeks to provide their various comments. The reactions should be sent at the latest by **May 22, 2017 at 18h00.**

After this period, Elia will consolidate the various comments and suggestions from stakeholders and these will be published on the Elia website. The answer of Elia to the comments will be published via a consultation report in June 2017 and will also be explained in the Task Force "Implementation of Strategic Reserve" of May.

3 Legal framework and process of sizing strategic reserve volume

3.1 Process

Article 7bis of the Law of 29 April 1999 concerning the organisation of the electricity market (‘Electricity Act’) includes the following timetable for determining the volume of the strategic reserve (also see Figure 1):

The following text is a translation from the Electricity Act (only available in French and Dutch). Elia assumes no responsibility for the accuracy of the translation of these legal articles and, in case of any doubt, the original text prevails over these translations. This applies also to other translations from the Electricity Act further in this report.

Art.7bis – 7quater

- ***Before 15 October**: DG Energy*[1] *provides the grid operator with any relevant information for the probabilistic assessment.*
- ***By 15 November**: the grid operator carries out a probabilistic assessment which is submitted to DG Energy.*
- ***By 15 December**: DG Energy provides the Minister with an opinion on the need to constitute a strategic reserve for the following winter. If the opinion concludes that such a need exists, a volume for this reserve is suggested, expressed in MW. As the case may be, DG Energy may issue an opinion recommending the constitution of such a reserve for up to three consecutive winters. If the suggested volumes relate to two or three consecutive winters, this proposal will determine for the last (two) winter(s) the minimum required levels, which may then be revised upwards in the subsequent annual procedures.*
- ***One month after receiving DG Energy's opinion**: the Minister may instruct the grid operator to constitute a strategic reserve for a period of one to three years starting from the first day of the next winter period and determines the size of this reserve in MW. The Minister notifies CREG of this decision. The decision, the grid operator's assessment and DG Energy's opinion are published on DG Energy's website.*

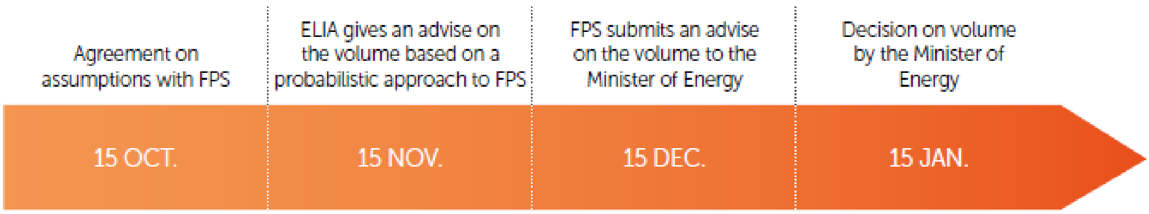


Figure 1

[1] Directorate-General for Energy of the Federal Public Service (FPS) Economy

The Electricity Act also includes the following **aspects** that need to be borne in mind for the **probabilistic assessment** regarding the security of Belgium's supply for the winter ahead:

Art.7 bis §4

- *the level of security of supply that needs to be achieved;*
- *the generation and storage capacities that will be available in the Belgian control area, based on such factors as planned cases of decommissioning in the development plan referred to in Article 13, and the communications received pursuant to Article 4bis;*
- *electricity consumption forecasts;*
- *the possibilities for importing electricity, given the capacities of the interconnectors available to Belgium, and, as the case may be, an assessment of the availability of electricity in the Central West European electricity market;*
- *The grid operator may, subject to appropriate justification, complement this list with any other item deemed useful.*

3.2 Legal notice period for production facility closure

In Article 4bis of the Electricity Act, the ultimate date is set by which a production facility can announce its temporary or permanent closure. This date is set to 31 July of the year preceding the effective date of the temporary or permanent closure.

Art.4bis, §1

Legal notice period for production facility closure according to Article 4bis *(translation)*

'Art. 4bis. § 1. In order to ensure the electricity security of supply and the safety of the grid, the unscheduled permanent or temporary closure of an electricity generation facility must be reported to the Minister, to the commission and to the transmission system operator by 31 July of the year preceding the effective date of the temporary or permanent closure. A temporary closure can only occur after 31 March of the year following the notification referred to in paragraph 1.

A permanent closure can only occur after 30 September of the year following the notification referred to in paragraph 1. A notice of closure is required for each installation for power generation connected to the transmission grid, whether a prior individual authorization in accordance with Article 4 was given or not.

§ 2. On the recommendation of the commission and of the transmission system operator, the King may determine the notification procedure in § 1, in particular as regards the form and modalities of the notice.

§ 3. No permanent or temporary closure, regardless of whether it is scheduled or not, may take place during the winter period.

§ 4. The provisions of this Article shall not apply to the units mentioned in the Act of 31 January 2003 on the gradual exit from nuclear energy for purposes of industrial electricity generation.'

3.3 Adequacy criteria

The Electricity Act describes the level of security of supply (adequacy) that needs to be achieved for Belgium. In the absence of harmonised European or regional standards, this level is determined by a **two-part Loss of Load Expectation (LOLE)** criterion (see Figure 2). The model Elia uses for the probabilistic assessment enables the calculation of both indicators.

LOLE < 3 hours

LOLE95 < 20 hours

Figure 2

- *"**LOLE**[2]": statistical calculation used as a basis for determining the anticipated number of hours during which it will not be possible for all the generation resources available to the Belgian electricity grid to cover the load[3], even taking into account interconnectors, <u>for a statistically normal year.</u>*
- *"**LOLE95**": statistical calculation used as a basis for determining the anticipated number of hours during which it will not be possible for all the generation resources available to the Belgian electricity grid to cover the load, even taking account of interconnectors, <u>for a statistically abnormal year[4].</u>*

In addition to the above indicators, which only pay attention to the number of hours when a full energy supply cannot be provided, the model used by Elia also gives an indication of the scale of the energy shortage (Energy Not Supplied or 'ENS') during these hours and the probability of a loss of load situation occurring (Loss Of Load Probability or 'LOLP'):

- **"ENS":** the volume of energy that cannot be supplied during the LOLE hours. This yields ENS (for a statistically normal year) and ENS95 (for a statistically abnormal year), expressed in GWh per year.
- "**LOLP**": the probability that at a given time a loss of load situation will occur, expressed in %.

The needed strategic reserve capacity is calculated based upon the assumption of 100% availability in order to fulfil the legal criteria in terms of security of supply. No distinction is made between demand reduction (SDR[5]) and generation capacity (SGR[6]):

- In the case of **SGR**, 100% availability assumption means that the strategic reserve will never be under maintenance during the winter, nor will it incur an unplanned outage. This differs from the modelling of the units available in the market (see section 2.1.1).

[2] LOLE: Loss Of Load Expectation

[3] Load: Demand for electricity

[4] The probability of occurrence of a statistically abnormal year is 1 in 20 (95th percentile).

[5] SDR: Strategic Demand Reserve

[6] SGR: Strategic Generation Reserve

- In the case of **SDR**, 100% availability assumption means that the strategic reserve can be called upon at any time throughout the winter, without any restriction in terms of number or length of activation.

The assumption of 100% availability of the SGR is an important one, especially in the case of large volumes, given that a cold spell (when the need for strategic reserve is at its greatest) may result in start-up problems for old units. The assumption of 100% availability of the SDR is also an important one as restrictions on the number and the length of activations are included in the contracts.

4 Proposed methodology for the determination of strategic reserve volume for winter 2018-19

The volume of strategic reserve is determined in three steps (see Figure 3).

The **first step** in determining the strategic reserve volume for a given winter consists of **establishing various future states** in which there is uncertainty surrounding the generation facilities and the demand for electricity. Each future state is established on the basis of historical data regarding meteorological conditions (wind, sun, temperature, precipitation) and power plants' unavailability (see below 4.1).

The **second step** involves **identifying periods of structural shortage**, i.e. times when the generation of electricity is insufficient to meet demand. To this end, an hourly market simulation is carried out using a market model for the winter period (from November until March inclusive). The market simulation is done for every future state established in the first step. This model is also used by RTE[7] in its adequacy studies for France, by other TSOs in the PLEF regional adequacy studies and in the ENTSO-E Mid-Term Adequacy Forecast report.

The **last step** is to determine the strategic reserve volume considered necessary to **meet the legal adequacy criteria** (see section 3.3). An iterative process is used to determine the total strategic reserve volume (see section 4.3).

This chapter takes an in-depth look at the various steps and the tools that are used.

Figure 3

[7] RTE: Réseau de Transport d'Electricité, the French transmission system operator

4.1 Definition of future states

A probabilistic risk analysis requires extrapolation of a large number of future states. Each of these states gives rise to an assessment of the number of hours of structural shortage. These various states make it possible to evaluate the adequacy indicators.

4.1.1 Random variables and time series

The key variables in this study can be subdivided into two categories: climatic variables and the availability of the generation facilities.

There are mutual correlations between the **climatic variables**:

- hourly time series for **wind energy generation;**
- hourly time series for **PV**[8] **solar generation;**
- daily time series for **temperature** (these can be used to calculate hourly time series of **temperature sensitive electricity consumption**);
- monthly time series for **hydroelectric power generation.**

However**,** the above mentioned variables are assumed not to be correlated with the others, namely:

- Parameters relating to the **availability of the thermal generation facilities and relevant HVDC interconnectors** on the basis of which samples can be taken regarding power plants' and HVDC' unavailability, due to forced outages.
- Seasonal constrains of forced outages or maintenance schedules are considered but no explicit correlation is assigned of these schedules and the climatic variables above mentioned.

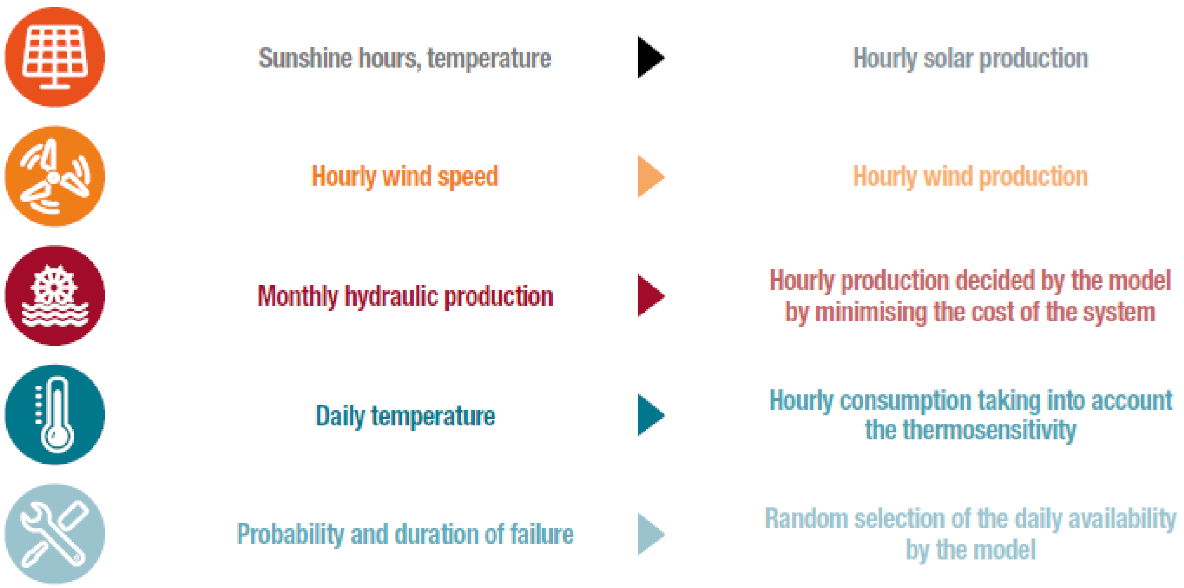


Figure 4

[8] PV: photovoltaic

The simulations performed in this study disregard the following events which may have an impact on generation adequacy (this list is not meant to be exhaustive):

- long-term power plant unavailability (sabotage, political decisions, strikes, maintenance due to inspections, bankruptcy, terrorist attacks, etc.). Those events if quantified are considered via sensitivities;
- interruption of the fuel supply for the power plants;
- extreme cold freezing water courses used for plant cooling;
- natural disasters (tornadoes, floods, etc.).

4.1.2 'Monte Carlo' sampling and composition of climate years

The variables discussed in section 4.1.1 are combined so that the correlation between the various renewable energy sources (wind, solar, hydroelectric) and the temperature remains. They are both **geographically correlated** and **time-correlated**.

Therefore, the climatic data relating to a given variable for a specific year will always be combined with data from the same climatic year for all other variables, with this applying to all the countries involved.

In contrast, for **power plant availability, random samples** are taken by the model, by considering the parameters of probability and length of unavailability (in accordance with the 'Monte Carlo' method). This results in various time series for the availability of the thermal facilities for each country. This availability differs in each future state.

Each 'Monte Carlo' year carries the same weight in the assessment (see Figure 5).

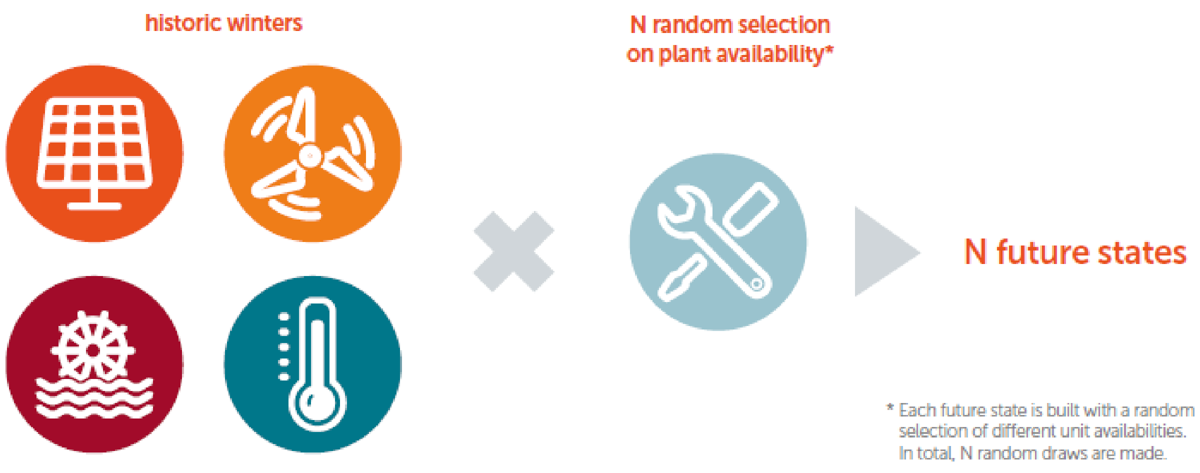


Figure 5

The Monte Carlo method

The '**Monte Carlo' method** is used in various domains, among them **probabilistic assessments of risks**. The name of this quantitative technique comes from the casino games in Monaco, where the outcomes for each game were plotted in order to forecast their possible results following a probability distribution translating the probability of winning.

In this same way, when a forecasting model is built, different assumptions are made translating the **projections** of the future system states for which expected values have to be determined. In order to do this, the parameters linked to the system state, characterised by inherent **uncertainty**, are determined and for each of these an associated range of values through a specific distribution function is defined (see Figure 6).

The **deterministic approach** considers that a unique state is associated with each system input. This means that the same output will provide independently the number of times the simulation is performed since the same input is used.

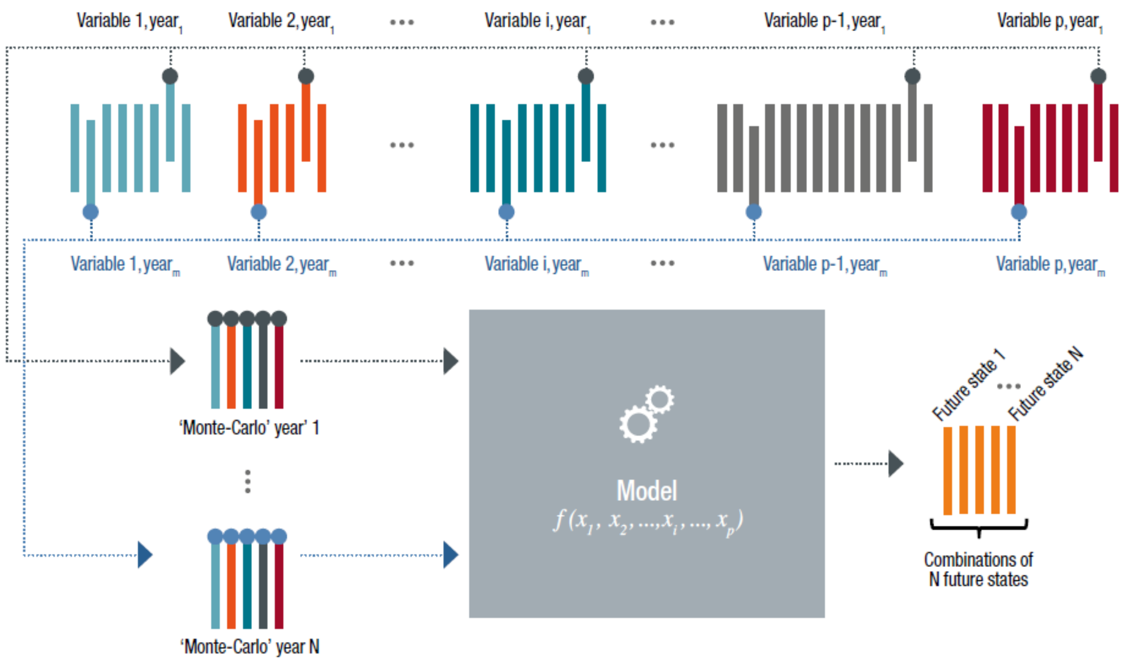


Figure 6

4.1.3 Number of future states

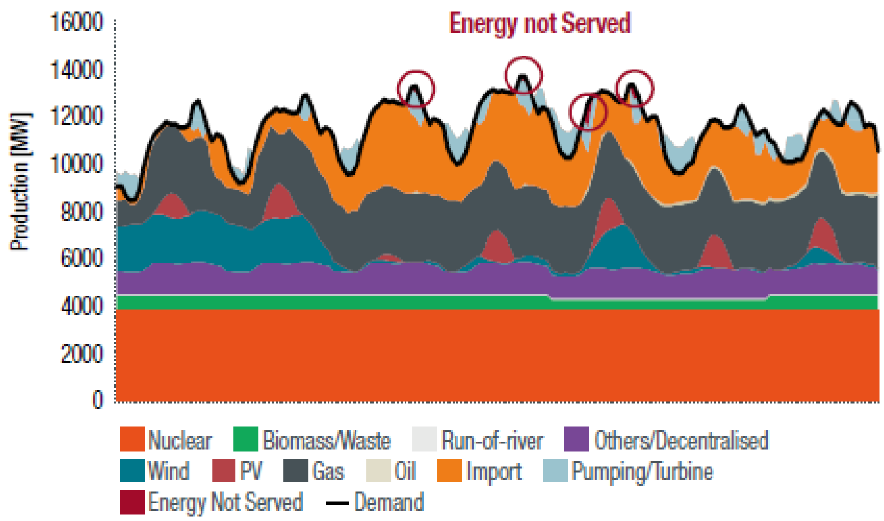
The number of future states that need to be calculated by the model to ensure the convergence of the results depends, among other things, on the variables, the simulated perimeter and the variability of the generation facilities. For the volume determination of strategic reserve the focus is on the two indicators determined by law, namely the average LOLE and the 95th percentile for the LOLE (LOLE95). The quantification of these two parameters has to converge to a desired level of accuracy which guaranties reliable results. *Convergence refers to the fact that average LOLE and LOLE95 settle into a value which does not change significantly when the number of N future states considered is further increased*. Depending on the scenario and level of adequacy lower or higher amount of 'Monte Carlo' years can be simulated.

Between 400 and 800 future states are required to achieve convergence of the indicators. This means that all 33 climatic winters will be simulated the necessary amount of times, with the availability of the thermal facilities being different in each of the simulated future states.

Combining the results of all these future states yields the distribution of the number of hours of structural shortage.

4.2 Identification of periods with structural shortage

Each future state is assessed on an hour-by-hour basis by simulating the European electricity market. The periods of structural shortage are the hours when there is insufficient generation capacity to cover a country's consumption. Figure 7 gives an example of how consumption is covered by the available generation and import facilities for every hour of the week. If, for a given hour, generation and import capacity falls even by only 1 MW short of the capacity required to meet demand, this corresponds to one hour of structural shortage. Figure 7 also presents the energy that cannot be supplied by the generation facilities.



Note that this example is only illustrative. Furthermore:
– The operational reserve was subtracted from the gas units
– The market response (decrease in demand by consumers in response to market prices) is not considered in this example

Figure 7

4.2.1 Input and output of the market model

To simulate the European electricity market, a number of assumptions and parameters have to be established. These are detailed in section 5.2 for Belgium and section 5.3 for its neighbouring countries.

The **key input data** for each country are:

- the hourly **consumption profile** and associated **thermosensitivity**;
- the installed capacity of the **thermal generation facilities** and the **availability parameters**;
- the installed **PV, wind** and **hydroelectric capacity** and associated **hourly production profiles based on the climate years**;
- the **interconnections** (by using the flow-based methodology or fixed exchange capacity between countries (NTC method)).

These data are introduced by means of hourly or monthly time series or are established for a whole year.

The power plants' economic dispatch is of little importance to the adequacy assessment: in periods of structural shortage, all of the available generation facilities will be taken into account, operating at their maximum capacity. However, the assessment also takes into consideration the power plants' marginal costs (see Figure 8). Using the economic dispatch enables the pumped-storage power plants and hydroelectric reservoirs to be appropriately modelled (see section 5.2.1.4).

Economic availability depends on the generation capacity available for the hour in question. The price in any given hour is determined by the intersection between the curve for supply (ranking of the power plants) and demand. The demand is considered inelastic in this context, at first. Then the market response to high prices is also taken into consideration, as explained in section 5.6.

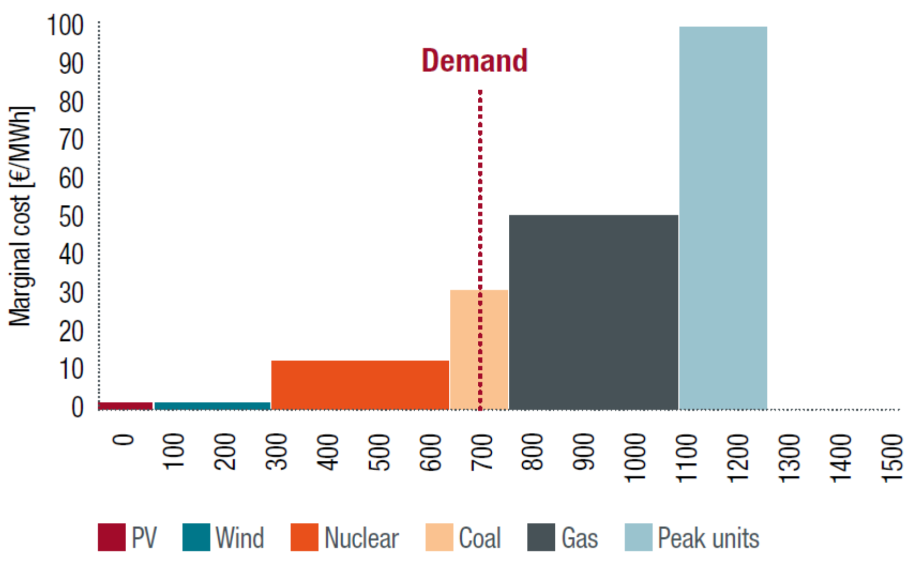


Figure 8

The **output of the model** that is assessed in this study consists of hourly time series showing the **energy shortage** for each country. These series can be used to deduce various indicators:

- the number of hours of structural shortage;
- the capacity surplus or shortage;
- the number of activations of the strategic reserve;
- Energy Not Served (ENS).

Figure 9 presents a schematic overview of the model's input and output.

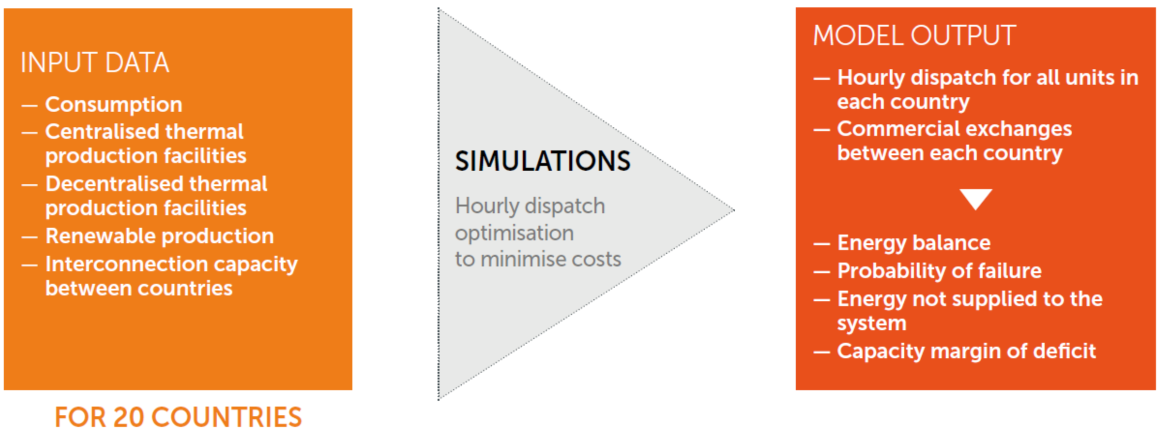


Figure 9

4.2.2 Model used to simulate the electricity market

The market simulator used in the scope of this study is ANTARES[9], a sequential 'Monte Carlo' multi-area simulator developed by RTE whose purpose is to assess generation adequacy problems and economic efficiency issues. This power system analysis software is characterised by these following specifications:

- representation of several interconnected power systems through simplified equivalent models. The European electrical network can be modelled with up to a few hundred of region-sized or country-sized nodes, tied together by edges whose characteristics summarise those of the underlying physical components;
- sequential simulation with a time span of one year and a time resolution of one hour;
- 8760 hourly time series based on historical/forecasted time series or on stochastic ANTARES generated times-series;
- for hydro power, a definition of local heuristic water management strategies at monthly and annual scales;
- a daily or weekly economic optimization with hourly resolution

This tool has been designed to address:

1) generation/load balance studies (adequacy);
2) economic assessment of generation projects;
3) economic assessment of transmission projects.

A large number of possible future states can be extrapolated by working with historical or simulated time series, on which random samples are carried out in accordance with the 'Monte Carlo' method (see section 4.1.2). The main process behind ANTARES is summarised in Figure 10.

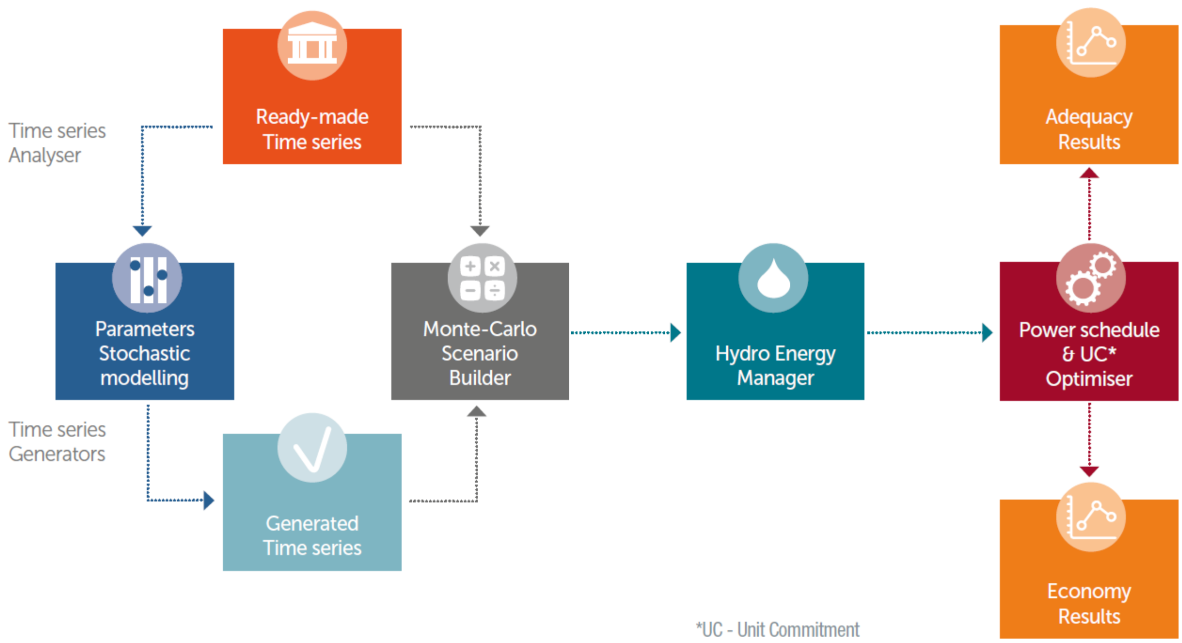


Figure 10

[9] ANTARES: A New Tool for Adequacy Reporting of Electric Systems

The model is used in many European projects and national assessments:

- the PLEF adequacy study [24];
- RTE French Generation Adequacy Report [3];
- the TwenTies project [4];
- e-Highway2050 [5];
- ENTSO-E's TYNDP[10] [6] and MAF [20];

Unit commitment (UC) and economic dispatch based on short run marginal costs

For each 'Monte Carlo' year, ANTARES calculates the most-economic unit commitment and generation dispatch, *i.e.* the one that minimises the generation costs while respecting the technical constraints of each generation unit. The dispatchable generation (including thermal and hydro generation) and the interconnection flows constitute the decision variables of an optimization problem whose objective function is the minimization of the total operational costs of the system. The optimization problems are solved with an hourly time step and a weekly time-frame, making the assumption of perfect information at this horizon but assuming that the evolution of load and RES is not known beyond. 52 weekly optimization problems are therefore solved in a row for each 'Monte Carlo' year. The modelling adopted for the different assets of the system is briefly described below.

Grid topology

The topology of the network is described with areas and links. (In this study, one area represents a country). It is assumed that there is no network congestion inside an area and that the load of an area can be satisfied by any local power plant.

Each link represents a set of interconnections between two areas. The power flow on each link is bounded between two Net Transmission Capacity (NTC), one for each direction.

Moreover, in ANTARES, some binding constraints on power flows can be introduced. They are in the form of equalities or inequalities on a linear combination of flows. They will for instance be used to model flow-based domains in the CWE market-coupling area.

Wind and solar generation

Wind and solar generation are considered as non-dispatchable and come first in the merit order. More precisely, as other non-dispatchable generation, they are subtracted to the load to obtain a net load. Then, ANTARES calculates which dispatchable units (thermal and hydraulic) can supply this net load at a minimal cost.

[10] TYNDP: Ten Year Network Development Plan

Thermal generation

For each node, thermal production can be divided into clusters. A cluster is a single or a group of power plants with similar characteristics. For each cluster, besides the time series of available capacity, some parameters necessary for the unit commitment and dispatch calculation will be taken into account by ANTARES:

- the number of units and the nominal capacities, defining the installed capacities;
- the cost, including marginal and start-up cost;
- the technical constraints for minimum stable power, must-run, minimum up and down durations.

Concerning the technical constraint for must-run, 2 values can be put: a value considered only if the plant is switched on (minimum stable power) and a value that, if higher than 0, forbids the plant to be switched off in the dispatch (must-run). The latter one is given on an hourly step time base, whereas the first one is a single value for the whole simulation.

Hydro generation

Three categories of hydro plants can be used:

- **Run-of-river** (**RoR**) plants which are non-dispatchable and whose power depends only on hydrological inflows;
- **Storage plants** which possesses a **reservoir** to store and control the use of water and whose generation depends on inflows and economic data;
- **Pumped-storage station (PSP**) whose power depends only on economic data.

Run-of-river generation is considered as **non-dispatchable** and comes first in the merit order, alongside with wind and solar generation.

For storage plants, the annual or monthly inflows are first split into weekly amounts of energy. The use of this energy is then optimised over the week alongside the other dispatchable units. Each hydro unit can generate up to its maximum capacity.

Pumped-storage plants have the possibility to pump water which will be stored and turbined later on. It is operated on a daily or weekly basis, depending on the size of its reservoir. ANTARES optimises the operation of PSP alongside the other dispatchable units while making sure that the amount of energy stored (taking into account the efficiency ratio of the PSP) equals the amount of energy generated during the day/week.

Demand response

One way of modelling **demand response** in the tool is by using very expensive generation units. Those will only be activated when prices are very high (and therefore used only after all the other available conventional generation capacity is dispatched). This is the way this study aims to replicate the impact of market response. Limitations on the number and duration of the activations per day and week of such demand response can be set on this capacity.

4.3 Evaluation of the strategic reserve volume or margin

If the legal criteria are not met following evaluation of the considered 'Monte Carlo' years, extra volume of capacity is needed. On the other hand, if the simulation without additional volume is already compliant with the legal criteria, the margin on the system will be reported.

An iterative process will be used to evaluate the total strategic reserve volume or margin (see Figure 11). The extra volume or margin will be increased in blocks of 100 MW until the legal criteria are met. After each increase, the market model repeats the simulation of 400 to 800 future states.

Figure 11

5 Hypotheses and data sources

In this section, we describe in detail the hypotheses and data sources that will be used for the determination of the volume of strategic reserve for the winter 2018-19. Section 5.1 focuses on the general hypotheses and data sources, while section 5.2 provides the details for Belgium in specific. The hypotheses and data sources for the other countries considered in the analysis are given in section 5.3.

5.1 General hypotheses and data sources

5.1.1 Simulation perimeter

Given the high amount of possible energy exchanges between countries, accurate modelling of the foreign countries is crucial in order to quantify structural shortage hours in Belgium. The simulated perimeter, consisting of 20 different countries, is shown in Figure 12.

The **Central Western Europe (CWE) zone** is comprised of Germany (DE), France (DE), Belgium (BE), The Netherlands (NL), Luxembourg (LU) and Austria (AT). Besides the CWE zone, the following other areas are modelled: Spain (ES), Portugal (PT), Great-Britain (GB), Ireland (IE), Northern Ireland (NI), Switzerland (CH), Slovenia (SI), Czech Republic (CZ), Slovakia (SK), Hungary (HU), Norway (NO), Denmark (DK), Sweden (SE) and Poland (PL).

Figure 12

5.1.2 Climatological data

Climatic variability is modelled using historical climate data of 33 historical winters. The concerned winters are those between 1982 and 2015. The following data sources are used:

- The data for **hydro power** production are obtained from the ENTSO-E data portal. These sources are available for the period 1991-2015 and for years before 1991 the data is reconstructed based on historical precipitation[11] data from the NCDC[12] [7].
- A tool has been developed in the context of ENTSO-E, which generates **load time series** taking into account the temperature sensitivity of each country. This tool will be used to construct the load time series, based on historical population-weighted temperature data procured in the context of ENTSO-E from MeteoFrance.
- Production data for onshore and offshore **wind and solar** power are procured in the context of ENTSO-E from the Technical University of Denmark (DTU). These production data are constructed based on amongst others historical wind and radiation data.

Table 1 summarizes the different climate data used, together with the data granularity and source.

Table 1

Data type	Granularity	Source
Temperature	Daily	Procured in the context of ENTSO-E from MeteoFrance.
Onshore and offshore wind production	Hourly	Procured in the context of ENTSO-E from DTU.
Solar power production	Hourly	Procured in the context of ENTSO-E from DTU.
Hydro power production	Monthly	ENTSO-E data portal, combined with extrapolation based on historical precipitation (NCDC).

5.1.3 Analysed timeframe

The analysed timeframe is the winter period as indicated in article 2, 51° of the Law of 29 April 1999 concerning the organisation of the electricity market [10] ('Electricity Act', translated from Dutch) :

"***Winter period***" : *period from November 1 until 31 March.*

The report will provide a probabilistic assessment of Belgium's security of supply and the need for strategic reserve for the upcoming winter, i.e. 2018-19. On top of the assessment for the upcoming winter, Elia will as well provide an indication on the need for the two following winters, i.e. 2018-19 and 2019-20. The different indicators will be calculated for these periods.

[11] Data of different meteorological stations per country.

[12] NCDC: National Climatic Data Center

5.1.4 Variable costs of production units

Variable costs of production units **do not influence** the volume determination of the strategic reserve as such. These costs are taken into account in order to obtain a more realistic economic dispatch of the production units.

5.1.5 Base case and sensitivities

The base case will be developed with the hypotheses and data sources as they are described in this document. Depending on the results of the analysis and on unexpected events which may arise, different sensitivities will be taken into account. Based on the sensitivities used for the adequacy report for winter 2017-18 [11], the following list provides a non-exhaustive overview of the parameters which might be considered when determining the sensitivities for the analysis of winter 2018-2019:

- Market response capacity and activation constraints
- Demand growth
- Availability of nuclear production
- Outage rates for production units
- Availability of generation units in other countries
- Long term loss of a critical grid element

5.2 Hypotheses and data sources for Belgium

This section elaborates on the data sources and the modelling techniques used in the analysis for Belgium. In **section 5.2.1**, the data sources and modelling techniques used with regard to **Belgian electricity supply** are detailed. Next, **section 5.2.2** elaborates on the **Belgian electricity demand** and the way its specifics are incorporated in the model.

In line with Article 7bis of the Electricity Law, Elia will receive input from the Directorate-General of Energy of the Federal Public Service (FPS) Economy prior to 15 October 2017. The information received from the FPS Economy will be integrated in the report and will be taken into account in the analysis.

5.2.1 Hypotheses on the Belgian electricity supply

5.2.1.1 Wind and solar power

The FPS Economy will consult the three Belgian communities, to obtain forecasts for the installed capacity of onshore wind and photovoltaic production. Elia bases itself on the latest information available to consolidate a forecast of the installed capacity of offshore wind. As described in section 5.1.2, historical data is used when modelling wind and photovoltaic production. The forecasts for installed capacity are combined with this historical data to obtain 34 different time series for onshore wind, offshore wind and photovoltaic production. This process is illustrated in Figure 13.

Figure 13

5.2.1.2 Biomass, Waste and Combined Heat & Power facilities

This section elaborates on the biomass, waste and Combined Heat & Power (CHP) production facilities for Belgium. The method for the consolidation of the installed capacity of each of the categories, as well the used modelling approach is discussed.

Installed capacity consolidation for biomass, waste and CHP

Elia maintains a database with information on both centralised and decentralised production units. This database is kept up to date on a monthly basis through exchanges with the distribution system operators and direct clients of Elia. Both units subject to a CIPU[13] contract, as well as units for whom such a contract does not apply are present in the database.

When the unit is subject to a CIPU contract, its owner has the obligation to notify Elia about the availability of the unit. The producer has to provide Elia with availability forecasts for both the long term (one year) and the short term (one day). In general, units for which no CIPU contract applies have a smaller installed capacity. It is agreed with the distribution system operator that all units with an installed capacity bigger than 0.4 MW have to be reported to Elia for inclusion in the database. In practice, also units with an installed capacity smaller than 0.4 MW are reported, either individually or aggregated. The database contains both information concerning units that are **in service**, but also projects that are currently in **development.**

In the same way as for onshore wind and PV (see section 5.2.1.1), the FPS Economy will consolidate a forecast for the installed **biomass** production capacity after consultation with the regions. For **CHP and waste**, the forecast of the installed capacity will be based on the information available in the Elia production database. Only projects communicated to Elia that are in a sufficiently advanced phase in their development will be taken into account in the analysis.

Biomass, waste and CHP modelling approach

In the ANTARES model, the biomass, waste and CHP units subject to a CIPU contract are modelled differently from those for which no CIPU contract applies. The units with a CIPU contract are modelled individually, with their specific characteristics in a similar way as the other CIPU units. The availability of thermal production with a CIPU contract is discussed more in detail in section 5.2.1.3.

For each of these three production types, power output measurement data has been analysed for a period of five years depending on the availability of the data. This gives the average hourly production profiles for each category. Based on an analysis of the availability of each of the three production categories, probabilistic outage draws are done, in a similar way as it is done for the thermal production units with a CIPU contract. However, for biomass, waste and CHP units no distinction is made between forced and planned outages. The probabilistic outage draws result in a different production profile for each 'Monte Carlo' year, thus improving the model by introducing a more realistic variability. In Figure 14, for a number of outage draws, the resulting combined production from waste, CHP and biomass is shown for three days. The figure also indicates the distribution of the production due to the outage draws.

[13] CIPU: Contract for the injection of Production Units. The signatory of the CIPU contract is the single point of contact at Elia for aspects of the management of the production unit injecting electricity into the high-voltage grid. The CIPU contract serves as the basis for the provision of other reserve power and the activation by Elia of such reserve power.

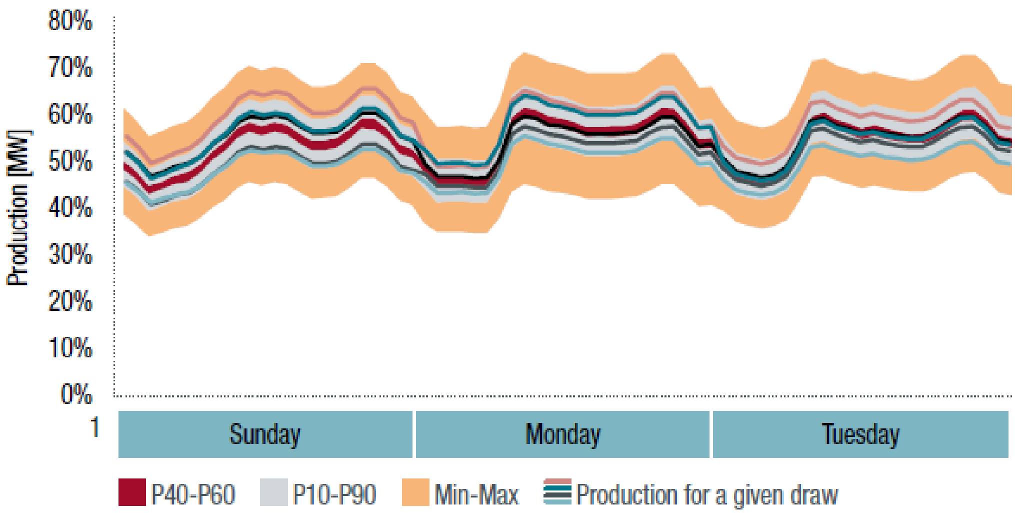


Figure 14

5.2.1.3 Thermal production with a CIPU contract

This section firstly elaborates on the installed capacity of the thermal units with a CIPU contract. Since units with a CIPU contract are modelled individually, outages on the individual units can be taken into account. This is described more in detail in section the second part of this section.

Installed capacity of the thermal production with a CIPU contract

The installed capacity of the Belgian thermal production with a CIPU contract will be consolidated by Elia and the FPS Economy based on the information provided by the producers to the Federal Minister of Energy, the FPS Economy, the CREG, and Elia as prescribed by the law.

The hypothesis used with regards to installed capacity **nuclear** electricity production will be aligned with the law accepted by the Belgian government concerning the nuclear phase out. This law was amended two times:

- The lifespan of the Tihange 1 power plant (installed capacity of 962 MW) was prolonged by ten years with the modification of the law in 2013;
- In June 2015, it was decided by the Belgian government that the Doel 1 and Doel 2 nuclear power plants (each with an installed capacity of 433 MW) could stay operational for ten additional years.

In line with the modified Belgian law on the nuclear phase out, it is assumed that all seven nuclear reactors (5919 MW) are operational for the whole length of the studied horizon. In recent years, several **thermal units** have been taken out of the market due to negative economic conditions. Some of these units were contracted in the context of the strategic reserve. For this analysis, it is assumed that all units currently participating in the strategic reserve will not return to the market.

Availability of the thermal production with a CIPU contract

The Belgian thermal production units with a CIPU contract are modelled individually in the ANTARES model. Their individual availability is determined by a probabilistic draw for each 'Monte Carlo' year (see section 4.1.2), based on historical availability rates. This way, a very high set of different availabilities can be drawn for each unit to be used in the simulations.

The analysis takes into account two types of unavailability for the CIPU production units:

- **Planned unavailability**, in general for maintenance, and;
- **Unplanned unavailability**, usually caused by an unexpected malfunctioning of the unit.

Planned unavailability

In recent years, less and less maintenance is planned during the course of winter. Together with the producers, Elia aims at scheduling all planned unavailability outside of the winter period. For 2018, a maintenance planning will be available at the start of the analysis. This planning will be taken into account in the analysis for winter of 2018-19. For this winter, the maintenance planning of 2019 is not yet known, and no planned unavailability of units for which a CIPU contract applies is considered. Similarly, for the analysis of winters 2019-20 and 2020-21, no planned outages will be considered in the course of the winter.

Unplanned unavailability

On top of the planned unavailability this study will take into account unplanned or forced unavailability. An analysis has been done for each production type (e.g. CCGT, gas turbine, turbojet,...), based on the historical unplanned unavailability for the period 2006 to 2015. The analysis is done using the availability information of the production units that are nominated in the day-ahead market and the result is shown in Figure 15. An update of this analysis will be performed taking into account the availability of the units in 2016.

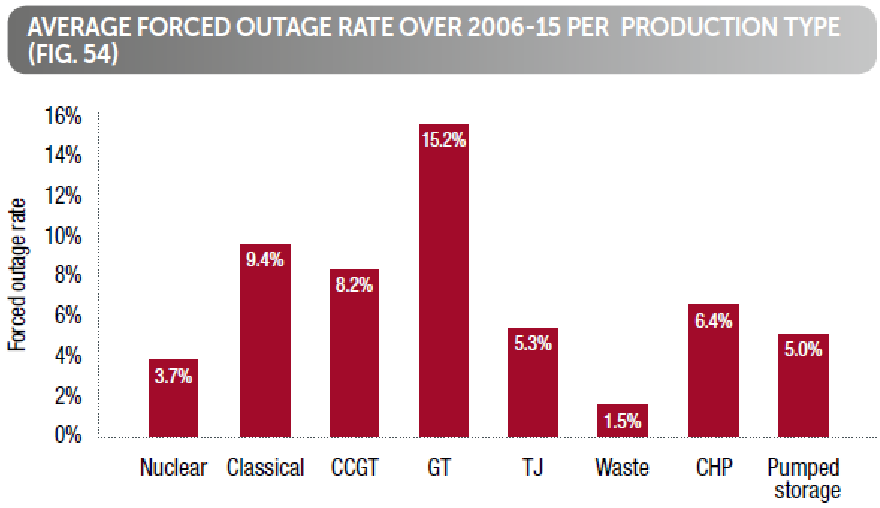


Figure 15

On top of the analysis regarding the frequency at which unplanned outages happen, the length of these outages has also been studied. For unavailability with a limited duration (i.e. intra-day outages), the balancing reserves can be used, see also section 5.2.1.5. Therefore, these outages do not have to be taken into account in the calculation of the necessary volume of strategic reserve.

For each production unit type, the probability given to the duration of an unplanned unavailability has been modelled separately. The analysis of the historical length of the forced outages has shown that unavailability of a limited number of days is more common. However, unplanned unavailability of longer duration can also occur, as is illustrated in Figure 16.

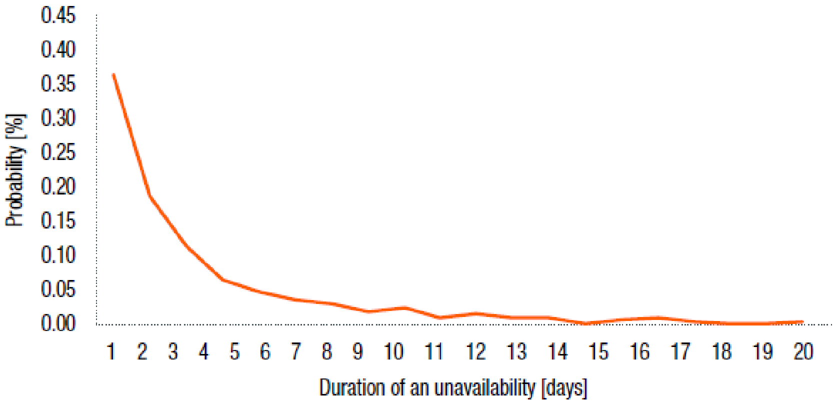


Figure 16

5.2.1.4 Hydroelectric power stations

The Belgian power system has two types of hydroelectric power stations:

- Pumped-storage units;
- Run-of-river units.

Belgium has ten **pumped-storage** units, six at the Coo power station and four at the La Platte Taille power station. The total installed turbining capacity amounts to 1308 MW, with the combined storage capacity equalling approximately 5800 MWh. Pumped-storage units are typically used to provide ancillary services. Therefore, the total reservoir capacity used for economic dispatch in this analysis is de-rated by 500 MWh. The available reservoir capacity for economic dispatch is equal to 5300 MWh.

In the ANTARES model, the ten Belgian pumped-storage units will be modelled individually which allows taking into account planned and forced outages on these units. The model determines the dispatching of the units using a daily cycle, taking into account the hourly electricity price (optimal economic dispatch, see section 4.2.2). When the model encounters periods of structural supply shortage (with prices reaching up to 3000 €/MWh), the pumped-storage units will be used at maximum capacity. In case the supply shortage lasts for longer periods of time, the model will dispatch the pumped-storage units in order to flatten peaks in the electricity use.

Run-of-river power stations in Belgium have an installed capacity of 114 MW at the end of 2015. Run-of-river power stations will be taken into account in the model by using 34 monthly historical profiles. Elia will update the installed capacity of the run-of-river power stations taking into account the information received from the FPS Economy.

5.2.1.5 Balancing reserves

In the context of its legal obligations, more specifically in accordance with article 8, §1 of the Electricity law, Elia is obliged to contract ancillary services to ensure a secure, reliable and efficient electricity grid [12]. These ancillary services, also called balancing reserves, are agreements with certain producers and consumers to increase or decrease production or demand of certain sites when needed. Using the balancing reserves, Elia can restore the balance between production and demand when an imbalance occurs. Such imbalances can be caused for example by the unforeseen loss of a production unit or renewable forecasting errors.

Since it has to be possible to deploy the balancing reserves to restore deviations independently from the strategic reserve, the volume contracted on production capacity for frequency containment reserves and frequency restauration reserves is taken into account in the simulations as a reduction of available capacity to cope with adequacy (the reserve requirements for BRP that have production units higher than the standard production unit capacity is also included). **Based on the latest available volume report of the balancing reserves, an update of the required capacities of reserves to be used in the context of this study will be done.**

5.2.2 Hypotheses on the Belgian electricity demand

The hourly total electrical load is forecasted for the next three winters. The construction of the consumption profile is also made for all the simulated countries and can be divided in 3 steps as shown in Figure 17.

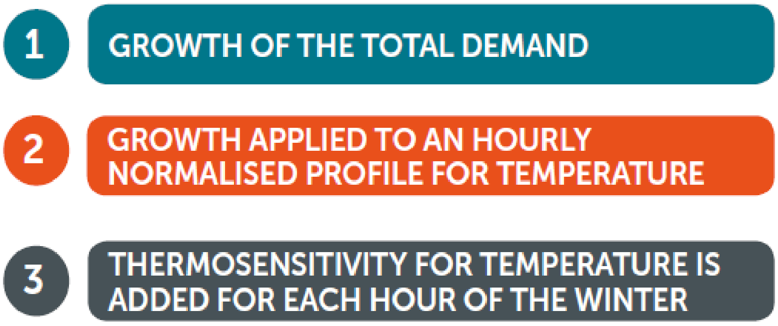


Figure 17

This results in 34 hourly total load profiles for each country. Figure 18 gives a more detailed overview of the construction process. The three steps are detailed in the upcoming sections.

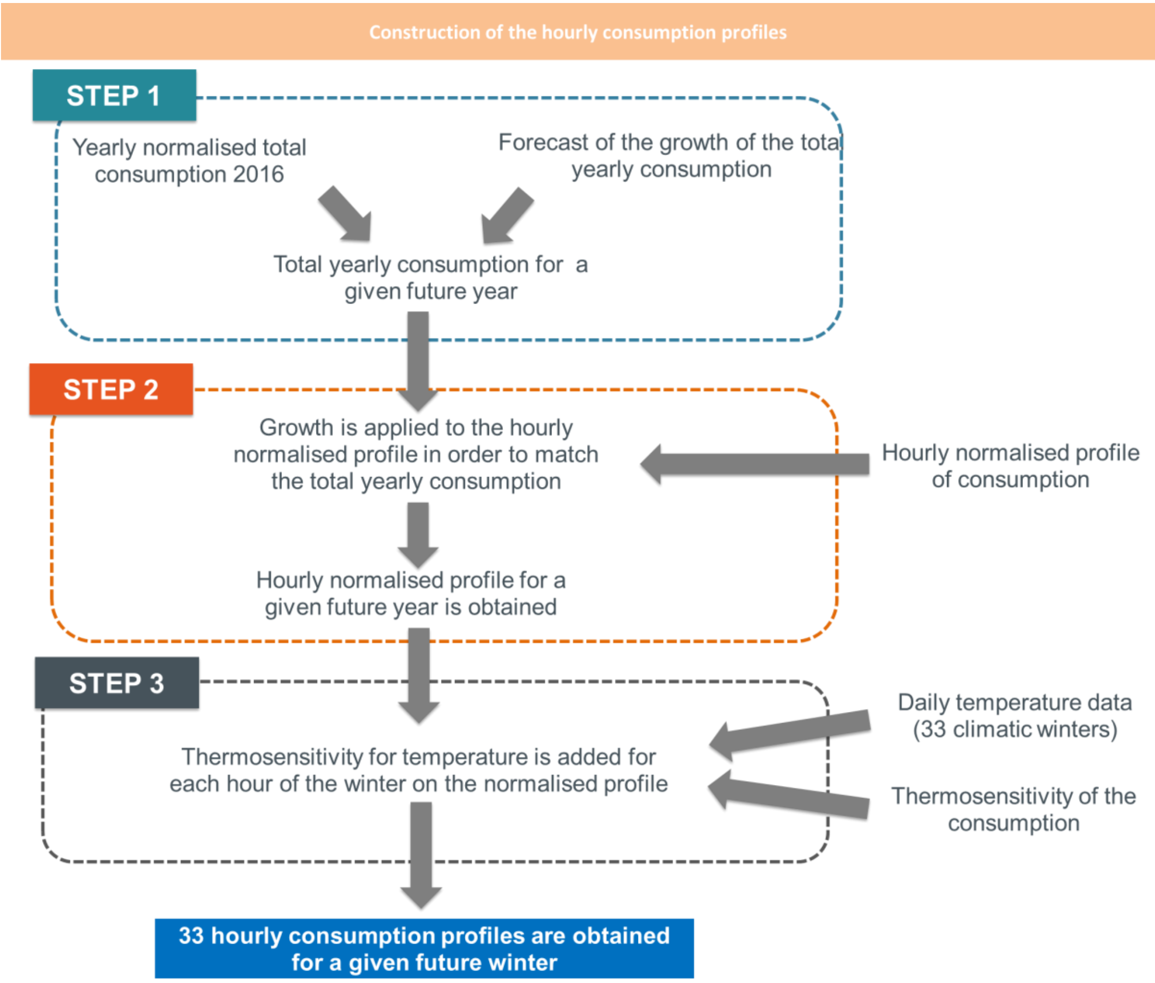


Figure 18

What is the total electrical consumption ('Total load')?

The total electrical consumption takes into account all the loads on the Elia net and all the loads on the distribution grid (including losses). Given the fact that quarter-hourly measurements are rare on the distribution grids, this load is estimated with a combination of computations, measurements and extrapolations.

What are the differences with the Elia consumption ('Elia grid load')?

The Elia-grid load is a calculation based on injections of electrical energy into the Elia grid. It incorporates the measured net generation of the (local) power stations that inject power into the grid at a voltage of at least 30 kV and the balance of imports and exports. Generation facilities that are connected at a voltage of less than 30 kV in the distribution networks are only included if a net injection into the Elia grid is being measured. The energy needed to pump water into the storage tanks of the pumped-storage power stations connected to the Elia grid is deducted from the total.

Decentralised generation that injects power at a voltage less than 30 kV into the distribution networks is not entirely included in the Elia-grid load. The significance of this last segment has steadily increased during the last years. Therefore Elia decided to complete its publication with a forecast of the total Belgian electrical load.

The Elia-grid comprises networks of at least 30 kV in Belgium plus the Sotel/Twinerg grid in the south of Luxembourg.

How is the consumption of the Sotel/Twinerg in Luxembourg taken into account?

The Elia grid includes grids with voltages of at least 30kV in Belgium but also in the grid of Sotel/Twinerg in the South of the Grand Duchy of Luxembourg. In this study the total load of Belgium excludes the consumption of the Sotel/Twinerg grid. This consumption is modelled a separate load connected to Belgium. More information can be found in section 5.3.5.

What is published on Elia's website?

Two load forecasts can be found on Elia's website: Elia grid load and Total load.

The Elia grid load and the total load as published on Elia's website include the load of the Sotel/Twinerg grid (this is not the case for the total load calculated in this study). The full explanation can be found on the website [17].

5.2.2.1 Growth in total Belgian load

The first step consists in forecasting the yearly total electrical load for a given country. After the normalisation of the 2016 total load for temperature, an estimation of the growth of the total demand is taken. Yearly normalised demand fluctuations are mainly due to economic indicators (GDP, growth of population, industry...), energy efficiency improvements and electrification (new usage of electricity, switching between energy sources).

For the analysis of the winter 2017-18, the latest forecast available at the time of the IHS CERA[14] consultancy bureau was taken as reference. A high sensitivity to this value was also evaluated taking into account the average yearly growth (2015-2020) of the demand from the EU reference scenario 2016. For the analysis of the winter 2018-19, the latest forecast available of IHS CERA will be used.

The growth in total Belgian demand will be taken into account in the total Belgian demand for the analysed year. The values used in the analysis for winter 2017-18 are shown in the chart in Figure 19. Given the fact that the year 2015 was warmer than the average, it leads to a normalised consumption that is higher than the historical observed value. On top of the total Belgian demand normalized for temperature, a climatic range due to the temperature sensitivity of the load will be applied.

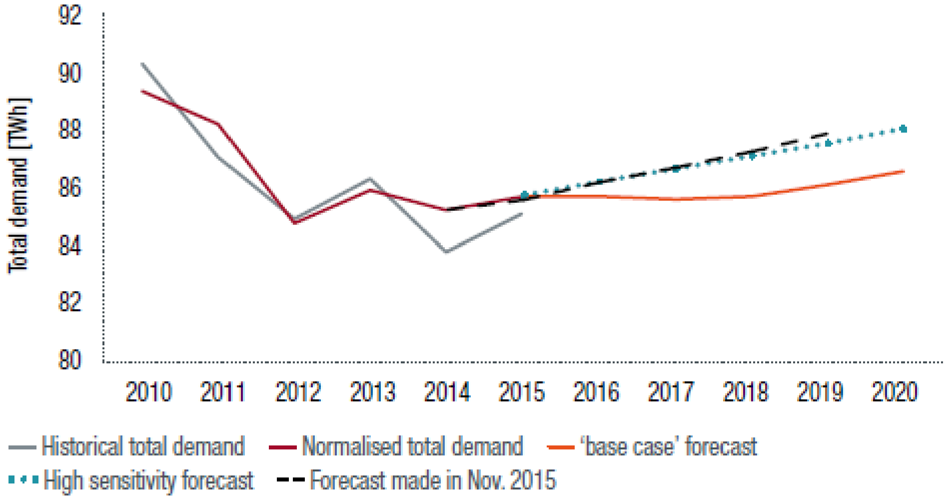


Figure 19

5.2.2.2 Load profile normalized for temperature

Once the total yearly normalised demand is forecasted for the future years, an hourly consumption profile can be constructed. In order to compute it, a normalised profile of the Belgian consumption is taken.

This so-called "normalized profile for temperature" should be understood as the typical profile of the expected demand for every hour of the year, corresponding to temperatures in normal climate

[14] IHS CERA: Information Handling Services Cambridge Energy Research Associates

conditions, so-called "normal" temperatures. Normalized profiles are constructed by statistical analysis of historical data on demand and on the average historical temperatures observed.

The growth identified in step 1 is applied to this normalised profile in order to match the total demand forecasted. The hourly normalised profile used for the analysis of winter 2017-18 is shown in Figure 20.

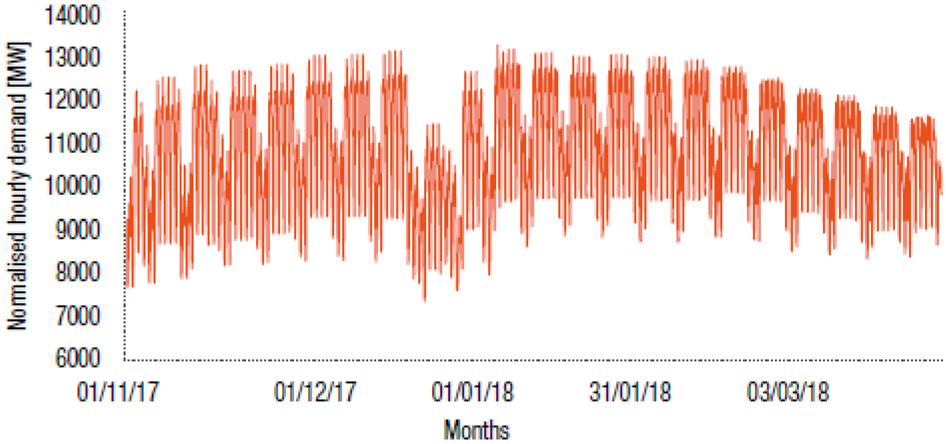


Figure 20

From Figure 20 one can clearly see the effects of week/weekend and the holiday effect on the consumption. Based on that profile, the peak demand is observed the second week of January. This peak demand is only valid for a normalised temperature. Applying temperature sensitivity to this profile will lead to very different hourly profiles with most of the time much higher peak consumptions.

The consumption of pumped-storage units is not taken into account in this profile. The dispatching of these units is optimised by the model, and their consumption comes on top of this profile. The impact of **market response** is taken into account up to some extent, as discussed more in depth in section 5.6.

In order to construct the normalised profile for consumption, historical data are used. Special days are flagged so that they are not taken into account in this analysis in order to avoid wrong forecasting of the total load (for example: strikes which lowered the consumption, balancing reserves activation or when market response in extraordinary conditions was present in the market).

This normalized profile will be updated with the latest information available to Elia.

5.2.2.3 Sensitivity of the load to temperature

The last step consists in applying the temperature sensitivity to the hourly normalised profile. For each of the 34 historical climate years, an hourly profile for consumption is created. This will allow the analysis to be carried out using 33 different hourly load profiles for the analysed winters. Figure 21 shows the impact of temperature on the total hourly profile for Belgium for one of the historical years used as climatic year for the analysis on the winter 2017-18.

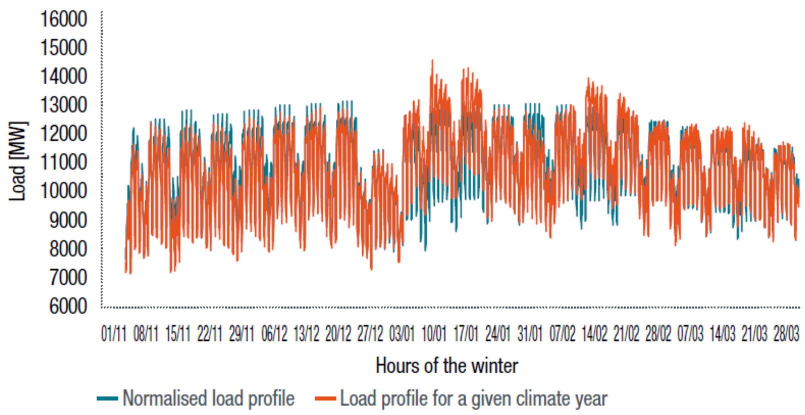


Figure 21

For the analysis of the winter 2017-18, the temperature sensitivity of the load was modelled using a linear relationship between the equivalent day temperature[15] and the average daily demand. For Belgium, based on an analysis of historical data, this relationship was determined at an increase of approximately 110 MW/°C (see Figure 22).

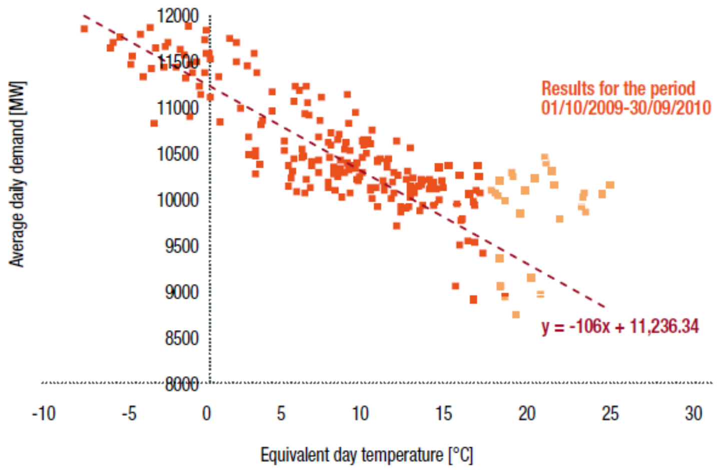


Figure 22

In the context of the ENTSO-E MAF study [20], a new methodology for incorporating the temperature sensitivity of the load has been developed. This new method relates the daily minimal and maximal power to the daily temperature (average over 24 hours). Furthermore, instead of a linear relationship, a cubical relationship is used which allows to capture in systematic way effects like saturation, while preserving the level of accuracy of the linear method previously used.

Elia has chosen to implement this new method, developed in the context of ENTSO-E, for the analysis of winter 2018-19. This allows the volume determination of strategic reserves to be more consistent with the methods developed at the European level.

[15] The equivalent day temperature takes into account the average day temperature of the two preceding days in the following way: 0.6 D + 0.3 (D-1) + 0.1 (D-2).

5.3 Hypotheses for the other simulated countries

This section elaborates on the hypotheses that will be used for the other simulated countries. For France, The Netherlands, Germany, Great Britain and Luxembourg these assumptions are constructed through detailed analysis and bilateral contacts. Consistency with European adequacy studies [20] is ensured as well.

5.3.1 France

The hypotheses for France that will be used in this study will be based on the most recent adequacy report ('Bilan Prévisionnel' [19]) issued by the French transmission system operator (RTE). RTE uses the same probabilistic method as well as the same model (ANTARES) to simulate the European electricity market. As the French adequacy is of the uttermost importance to the results of this analysis, assumptions and methods are aligned through frequent bilateral contacts between Elia and RTE.

5.3.2 The Netherlands

The assumptions that will be used in this study for the Netherlands, will be collected through bilateral contacts with the Dutch TSO TenneT. They will be in line with those used for the Dutch national adequacy study ('Rapport Monitoring Leveringszekerheid' [23]), which is usually published in July.

5.3.3 Germany

The assumptions that will be used in this study for Germany are a compilation of bilateral contacts with German TSOs, market data from transparency platforms (EEX, ENTSO-E), adequacy studies performed by the German regulator and other various data.

5.3.4 Great-Britain

For Great-Britain, the assumptions that will be used in this study will be based on the 2017 version of the Future Energy Scenarios (FES), for which the stakeholder feedback has already been published [13]. The FES are constructed on a yearly basis by the British TSO National Grid, describing a set of scenarios up to 2050. These scenarios are subject to a wide stakeholder consultation, and are used amongst others in the National Grid Electricity Capacity Report (ECR) and the National Grid Network Options Assessment (NOA).

One of the four FES 2017 scenarios will be chosen to be used in this analysis upon the publication of the FES documents in July 2017. For the period 2018-19 up to 2020-21 however, the variations amongst scenarios will be relatively small. Therefore the choice of this scenario will not be very impacting on the results of this analysis.

5.3.5 Luxembourg

The modelling of Luxembourg is important for Belgium as a part of the country is connected to the Belgian control zone (this is indicated as the 'LUb' zone in Figure 23). In 2016, the CCGT located in Luxembourg but belonging to the Belgian regulation zone was closed definitively [14]. Following this closure, the 'LUb' zone includes only consumption. The consumption of that zone is therefore taken into account as part of Belgian load. The 2 other electrical zones of Luxembourg are:

- a part connected to France (LUf in Figure 23) that only contains load;
- the rest of the country is connected to Germany. This zone includes all the hydro, wind, PV and the remaining load of the country;

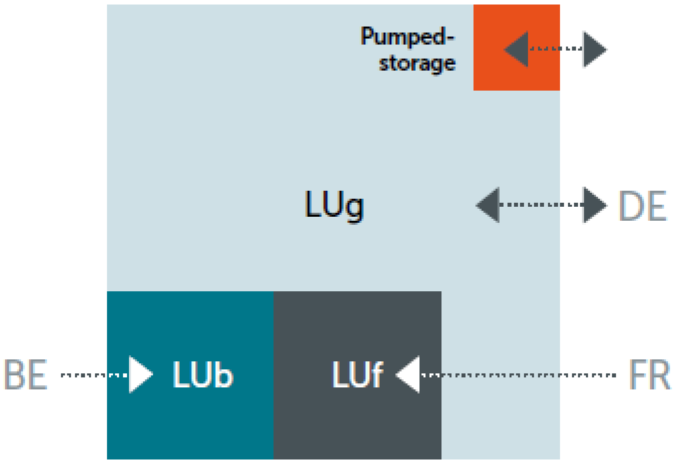


Figure 23

5.3.6 Other countries modelled

In total twenty countries will be modelled in this study. For each country, hypotheses will be made in terms of non-renewable generation facilities, demand and renewables. Most of these hypotheses will be taken from pan-European adequacy studies such as the 'Mid Term Adequacy' forecast [20], ENTSO-E transparency platform [9], ENTSO-E statistics [8], bilateral contacts, PLEF adequacy study [24], national reports and other statistics.

5.4 Hypotheses for interconnectors

In previous studies (assessment for winter 2016-17 and earlier) interconnections between countries were modelled using fixed values for the maximum commercial capacity available for commercial exchanges between two interconnected countries. The actual commercial exchange of energy per hour for a given year situation is the result of an economic optimization of the market model. In moments of structural deficit in one area, commercial exchange should always go in the direction of the area which has a production shortfall and correspondingly the relative higher electricity price.

As of the analysis for winter 2017-18, the interconnections have been modelled between the countries, as in the day-ahead market coupling mechanism. France, Netherlands, Germany (linked to Luxembourg and Austria) and Belgium are therefore modelled using the flow-based (FB) methodology (see section 5.5 on this methodology). Thanks to the more detailed description of the network within the flow-based methodology, use of the interconnections and price convergence can be improved without compromising the level of security of supply.

For countries outside of the CWE FB zone, the interconnectors will be modelled on the basis of values of the commercial exchange capacity between countries. The import and export capacity available for commercial exchanges, also referred as Net Transfer Capacity (NTC), is calculated by the Transmission System Operators (TSOs). The NTC values are calculated based on the technical characteristics of the lines and the internal limitations of each TSO.

Figure 24

5.4.1 Belgium's import and export capacity

Belgium is currently electrically interconnected to France, the Netherlands and Luxembourg (part of the Elia control zone for the Sotel/Twinerg grid). This allows the country to export or import energy depending on market conditions in Europe.

Interconnection capacity, import capacity, import saldo and net position

Available interconnection capacity considers a safe state (N-1) of the network in real operating conditions. Consequently, not all capacity can be released in advance.

This does not necessary means that maximum import capacity will be available in all cases as it is linked to total availability of the grid and without taking into account market conditions. If there are restrictions on the domestic or foreign grids or if the physical flows resulting from market conditions imply export at one of the borders or if energy abroad is not available, the maximum capacity might not be used fully. The actual usable capacity is called the '**import saldo'**.

Since exchanges are determined by market conditions (demand and supply in each country), Belgium's actual import depends on the situation of the European market. The country's net position is the sum of exports minus imports that are determined by market conditions (based on demand and supply curves).

Belgium is in the heart of the interconnected European grid. It is surrounded by France, the Netherlands and Germany, which, depending on the situation of their respective grids and markets, can each import or export large amounts of electricity. Given the fact that the European electricity grid is meshed (like a spider web composed of many loops where electricity can flow via different paths), any transaction between two countries will flow partially through the grid of neighbouring countries and generate so-called 'non nominated physical flows'. For Elia, those flows are an uncertainty factor in the computation of the commercial exchange capacity with its neighbours. With the massive rise of renewable energy, mainly in Germany, this variability has increased significantly in the last years.

The flow-based methodology allows to better take into account the impact of trade exchanges between countries.

Maximum simultaneous import capacity on the AC grid

The simultaneous maximum import capacity of Belgium is the maximum power that the country can import under normal grid operation conditions, meaning without either planned or forced outages of the grid infrastructure (in Belgium and in the neighbouring countries) and without knowing the electricity flows in advance. This capacity depends on available resources for voltage regulation, short-circuit power, and inertia that are normally offered by the countries' internal production. It is an input into the flow-based domain calculation. In practice, the maximum possible simultaneous import capacity for Belgium as determined by the flow-based domain will also depend on seasonal effects, availability of the grid in Belgium and neighbouring countries, and market conditions. Due to unknown events that can take place at any moment, this capacity is given to the market with yearly, monthly, day-ahead and intraday portions.

For the analysis of winter 2018-19, a maximum import capacity via the AC grid will be considered in the simulations by considering the effect of the current planned investments, past observations and knowledge at Elia about the operation of the BE grid.

In the future, reinforcements of the Belgian backbone grid and cross-border lines are planned as detailed in the Federal Network Development Plan [25]. In particular new connections with Germany and Great Britain in HVDC are being built and will reinforce and increase the country's current export and import capacity.

The actual import saldo availability is subject to two essential conditions:

– market conditions must be favourable for import;

– network operating conditions must be in a normal state.

Regarding the specific market conditions, international flows may imply that the available import balance will be significantly lower than average in some hours. The flow-based modelling approach makes possible to take these effects into account.

5.4.2 HVDC forced outages

Availability of the HVDC system elements will be included in the simulation as forced outages. *The incorporation of outages of (selected) HVDC lines in the simulations is a new methodological improvement compared to previous assessments.*

Forced outages are represented by the parameter Forced Outages Rate (FOR), which in this case defines the annual rate of forced outages occurrences of HVDC lines. Forced outages are simulated by random occurrences of outages within the probabilistic Monte Carlo scheme, while respecting the annual rate defined. Simulated random forced outages of HVDCs allow to consider the impact of availability of interconnectors in the adequacy assessment.

An unavailability rate for each HVDC interconnector of 6% will be used as benchmark value, following the ENTSO-E's MAF report [20]. It is noted that 6% is only the average value, but assuming the same unavailability for each interconnector is a pragmatic approach and would not overestimate the unavailability of HVDC links.

5.4.3 Fixed commercial exchange capacity on the borders of the countries outside the CWE region

Assumptions

Countries outside the CWE region and the interconnections between the countries of the CWE region and the rest of Europe are modelled using a commercial exchange capacity also referred to as Net Transfer Capacities (NTC). These values are from studies conducted within ENTSO-E and from bilateral and multilateral contacts and take into account grid investments planned for future winters.

The NTC's also vary from day to day depending on the conditions of the network, availability of lines and other network elements. As such they are provided by TSOs on annual and monthly values and are regularly updated on weekly and daily basis. In this study, a single reference is used for a particular interconnection in a certain direction throughout the simulated period.

Historical exchange capacities can be found on the respective TSOs website and transparency platform of ENTSO-E [9].

Exchange with the non-modelled countries

No exchanges between the countries that are modelled and those that are not modelled are considered. This is a conservative assumption because these exchanges do exist and could contribute to power supply of the CWE region. The modelled countries besides the CWE countries[16] are: Spain (ES), Portugal (PT), Great-Britain (GB), Ireland (IE), Northern Ireland (NI), Switzerland (CH), Slovenia (SI), Czech Republic (CZ), Slovakia (SK), Hungary (HU), Norway (NO), Denmark (DK), Sweden (SE) and Poland (PL). Since the geographical perimeter considered around Belgium is significant, the effect of the above mentioned assumption has little impact on the adequacy situation in Belgium.

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[16] Germany (DE), France (FR), Belgium (BE), The Netherlands (NL), Luxembourg (LU) and Austria (AT)

5.5 Flow-based method applied for the CWE-zone

5.5.1 Why flow-based methodology is included in this study?

As Belgium is in the centre of the CWE zone, the country's import and export capabilities are currently entirely defined by the flow-based methodology used at regional level for the day-ahead markets. Belgium's net position is therefore linked to the net position of the other countries in the CWE zone and to the flow-based domain defining the possibilities of energy exchange between those countries. It is therefore critical to replicate market operation in order to quantify the country's loss of load expectation.

The flow-based method allows to properly take into account interactions between market outcomes and the transmission grid. For instance, at moments when both France and Belgium are in structural shortage, the import saldo of Belgium can be significantly reduced if large flows are running through Belgium towards France. The use of the flow-based method in this assessment, makes it possible to calculate the likelihood and impact of a reduced import saldo on adequacy as a result of market conditions in neighbouring countries.

Figure 25 shows the flows between four fictitious zones when 100 MW is exchanged from zone A to zone D. The resulting flows follow the path of least impedance. This will result in flows between zones not participating in this energy exchange (zones B and C for example).

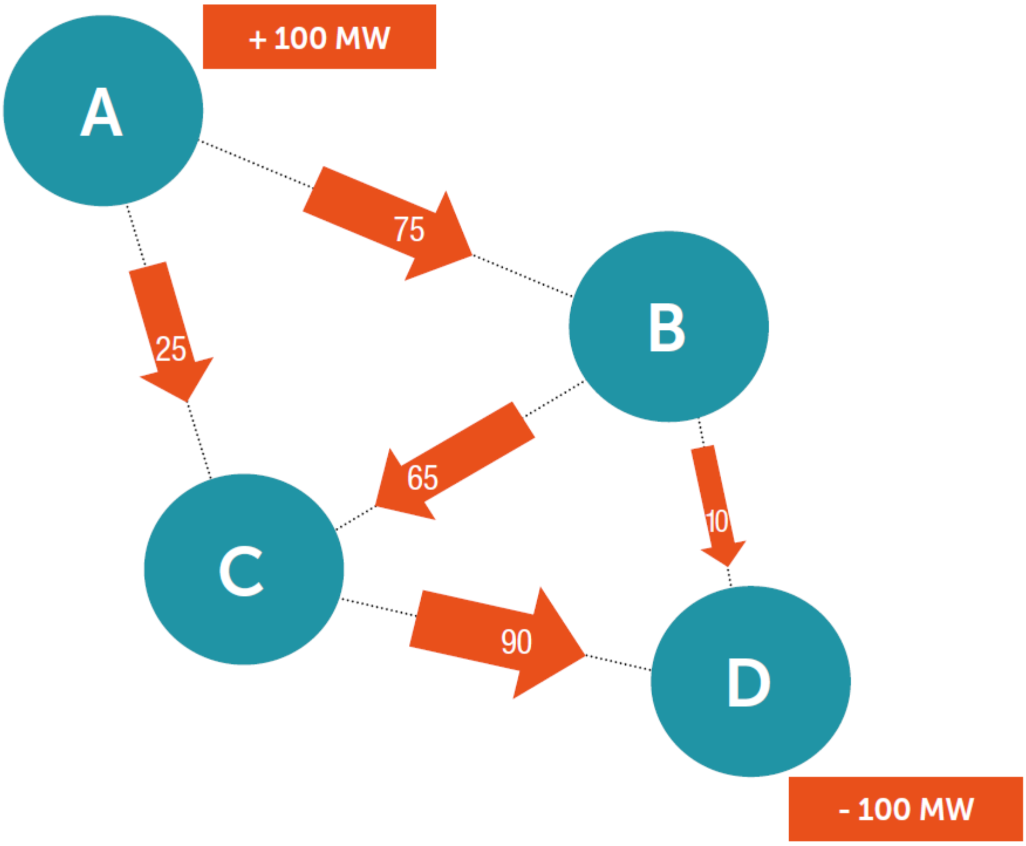

Figure 25 Example: Commercial exchanges between two countries can generate physical flows through other borders (resulting physical flows from an energy exchange of 100 MW between 2 zones).

5.5.2 How will flow based be taken into account in the study for winter 2018-19?

To date, most market simulations that calculate the economically optimal energy dispatch ensuring the balance of the demand and supply in interconnected systems, are mainly based on fixed values of commercial exchanges at the borders.

Market simulation tools and methods are developed to allow for various distribution factors and integration of various flow-based domains for each hour of the year, which makes it possible to achieve market modelling results closer to the ones observed in flow-based market coupling.

For details on the flow-based method and calculation of flow-based domains see Appendix 6.

The adequacy patch

The CWE flow-based algorithm includes a so-called adequacy patch defining rules for sharing energy exchanges in scarcity situations.

If a country has a structural deficit (day-ahead price reaches 3000 €/MWh in that country) the maximum import capacity will be allocated to that country independently from the market conditions in the other countries.

When two or more countries simultaneously have a structural deficit, imports will be allocated to those countries in proportion to their respective needs, on the basis of a quadratic function defined in the Euphemia market coupling algorithm [18].

For the purposes of the adequacy study, the adequacy patch is taken into account in the results from ANTARES in post-processing.

5.5.2.1 Improved method for determination of flow based domains for winter 2018-19

Building on the experience of previous assessments for winters 2016-17 and 2017-18, several flow-based domains will be used for the winter 2018-19 assessment. The planned grid reinforcements to be commissioned before winter 2018-19 will be taken into account in the calculation of the relevant flow-based domains.

How will the representative domains be chosen and for which situations?

Three main steps (see Figure 26) will be followed to define and implement the relevant flow-based domains for winter 2018-19:

1. Selection of "typical" days.
2. Determination of the correlation between the typical days and specific climatic conditions.
3. Assignment of the flow-based domains to the hourly market simulation based on the correlation determined in step 2.

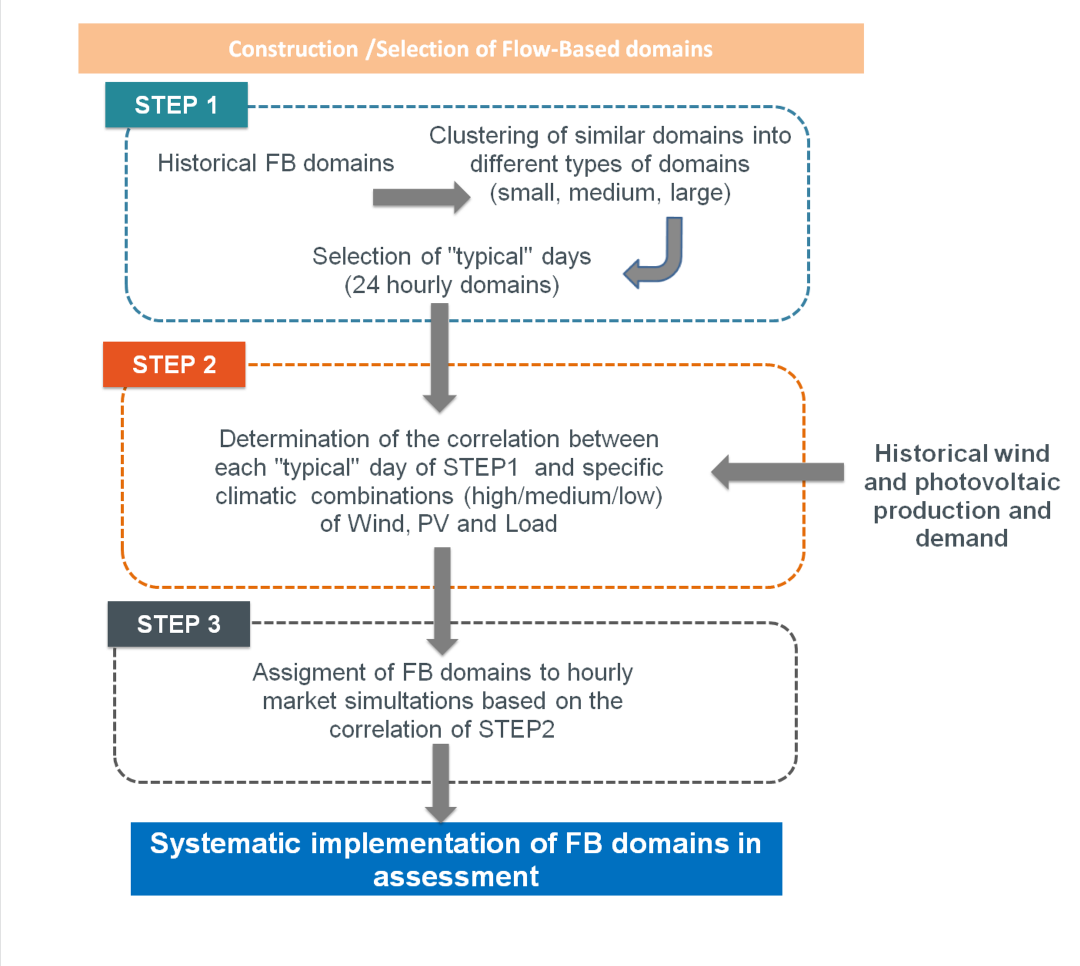

Figure 26 Implementation of FB domains in market simulations

Step 1: Selection of "typical" days

- Statistical analysis of the geometrical shapes of available flow-based domains is performed on historical records of domains from the FB CWE operational tool [18].
- Historical days are therefore clustered in families defined by the size of their 24 hourly domains, *i.e.* typically "large", "medium" and "small" families of domains are clustered. Each typical day consists of 24 hourly domains (one for each hour).
  - ➢ Small domains correspond to situations with a highly congested network and therefore with small values for the maximum power exchanges possible between the different market areas considered by the given domain (related to the small volume inside the domain).
  - ➢ Large domains correspond to situations with a less congested network and therefore relatively higher values of maximum possible power exchanges between the market nodes considered by the given domain (larger volume).
  - ➢ Then a typical day is the historical day within a given family or cluster of domains which provides the best representation of all the other days in the cluster.
  - ➢ Flow-based domains being hourly, this typical day is selected by comparing its domain at every hour to the other day's equivalent domain (at the same hour).

Step 2: Correlation between each "typical" day and specific climatic combinations

- Twelve typical days will be found by the analysis of Step 1: 4 typical days for winter, 4 typical days for summer and 4 typical days for the inter season.
- A probability matrix will be calculated as a function of daily energy ranges (high/medium/low) of wind, PV and load. This calculation provides the correlation of each typical day (24 hourly domains) to given climatic combinations (eg. low wind, medium PV, high load).

Step 3: Assignment of FB domains to hourly market simulations

- The typical days for winter of Step 1 are used as *proxies* for the relevant domains expected during next winter 2018-19 and will be assigned to hourly simulations by the correlation found in Step2.
- Each hourly simulation of the interconnected power system presents different expected climatic, generation and demand situations during next winter.
- Such systematic approach allows to link specific combinations of climate conditions expected next winter e.g. high /low wind infeed in Germany, high /low temperature and demand in France and Belgium etc..., with representative domains for these conditions.

Data comprising observations of the previous two winters: winter 2015-16 and winter 2016-17 will be analysed for this purpose.

The method sketched above and to be used in the determination of the volumes of strategic reserve needed for winter 2018-2019 is consistent with the method developed by RTE and to be used in the Bilan Prévisionnel 2017.

5.5.2.2 What changes will be made to the "representative operational domains"?

Recent and upcoming investments in Belgium on the 380kV grid already operational or scheduled to be operational before the start of winter 2018-19 and which are considered relevant for the calculation of flow-based domains to be used on the assessment are:

Winter 2018-2019

- BRABO I: 380.26 Doel-Zandvliet + 2nd PST at Zandvliet
- Split of the line 380.73 (Doel – Horta) in two segments: 380.53 (Doel – Mercator) and 380.73 (Mercator – Horta)
- 2nd 380kV circuit Lixhe-Herderen + new GIS substation 380kV at Lixhe
- The margin given by installations for monitoring the lines ('Dynamic Line Rating: Ampacimons') will be integrated where available.
- Stevin project

Changes to the historical domains will be applied in some cases in order to match for these upcoming investments. Furthermore, all nuclear units will be set to maximum output in the historical day files that are used to construct the flow-based domains.

Furthermore, note that the flow-based domains are computed with the current operational rules and include an N-state and N-1 state computation. The starting N-state taken into account for this computation is the one of the historical day. Therefore maintenance or outages known when the domains where computed as well as the topology of the grid are taken from the historical days.

Note on planned investments for winter 2019-20 & winter 2020-21

Investments in Belgium on the 380kV grid beyond the ones above are under consideration for the adequacy assessment by Elia within the timeline of winter 2019-20 and winter 2020-21. Updates of the CWE FB operational tool are planned in order to take into account these new investments in the calculation of FB domains, when relevant/impacting the CWE market coupling area.

On one hand, Nemo Link® [21], the HVDC connection with Great Britain, will be taken into account for winter 2019-20 in the 'base case', modelled as an NTC link without impact on the flow based domains, as the current date of finalisation is in 2019. This connection has an exchange capability of 1000 MW between Belgium and Great Britain.

The planned HVDC interconnection with Germany (ALEGrO project [22]) has a target commissioning date of 2020. Given the uncertainty regarding the integration of the ALEGrO project in the flow-based operations however, this interconnection will not yet be part of the base case analysis. Elia will be performing tests on the correct integration of the ALEGrO interconnector in its adequacy assessments and, depending on the results of its analysis, could analyse a sensitivity on the ALEGrO implementation in the flow-based method for its adequacy assessment.

IC BeDeLux project

The IC BeDeLux project will not be included in the simulations, since the one year technical trial phase for this interconnector has not started yet and the commercialization of this connection between the Belgian and Austrian/Luxembourg/German market hub is only foreseen after this one year trial phase.

Assessing the impact of the long-term loss of a grid element on the representative flow based domains

The long term unavailability of a grid element is not taken into account in the calculations of the volume of strategic reserve in the 'base case'. The impact of such a loss will be assessed as sensitivity in this study. Given the very low probability of such an event and taking into account the fact that various actions could be taken by the TSOs to maximise market exchanges (topology changes, remedial actions, emergency lines, etc.), it can be considered as a stress test.

5.6 Integration of the Market Response in Belgium 2017[17]

Market Response is a crucial market dynamic during difficult situations on the electricity grid, especially in tough conditions, when adequacy problems arise. European (2009/72/CE and 2012/27/CE) and national policy makers as well as regulators are pushing for an increased development of Demand Side Response (DSR) and Market Response (MR)[18]. This effort is mirrored by market stakeholders' demands (FRP, BRP, producers, suppliers, third party aggregators and customers) to fine-tune the methodology used to identify the volume of Market Response in Belgium in the context of the volume determination of strategic reserve.

In 2015, Elia has launched a questionnaire to the BRPs, Elia grid users and/or aggregators to estimate the Market Response in moments of systems stress. In 2017, key stakeholders on the market have expressed their willingness to be involved with the development of a new methodology to determine Market Response in Belgium in the scope of the volume determination of strategic reserve. In the context of the "Implementation Strategic Reserve" task force, a subgroup "Demand Response Study" was created in January 2017 to design the most adequate methodology for determining these volumes of Market Response. The methodology was designed based on interactions with stakeholders, over the course of four workshops and bilateral interviews.

Market Response, as used in the context of the volume determination of strategic reserve, encompasses all market reaction in the energy-only market to extraordinarily high prices. Market reaction in normal price conditions (prices < 150€/MWh) is already considered in the normalized load profile constructed by Elia for its adequacy study. The newly developed methodology allows determining the volume of Market Response that is available when extraordinarily high prices (> 150€/MWh) occur. It was concluded that the method can estimate the market response across all different consumer segments.

Based on close workshops and inputs of consultants, it was concluded that all available Market Response can be taken into account with the following three-fold approach: the global market response volumes will be estimated based on the analysis of the aggregated demand and supply curve of the day-ahead market of EPEX Belgium (section 5.6.1). This analysis will be complemented with a qualitative questionnaire (section 5.6.2) to assess the activation details and finally verified with a sanity check (section 5.6.3).

5.6.1 Aggregated curves analysis: global volume estimation

The aggregated curves methodology enables to estimate the total volume of Market Response for the contract based, price based MR and voluntary MR categories. In the aggregated curves, Market Response volumes can be valued as a demand decrease or as an offer increase. These two elements are discussed in the following paragraphs.

5.6.1.1 Demand decrease

The demand decrease due to a price increase is directly present in the aggregated curves by studying the volume decrease associated to the price increase from 150€/MWh (bottom price limit of the market response volumes) to 3000€/MWh (maximum day-ahead price). Since, the aggregated curves are provided for each hour, this volume comparison is computed hourly.

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[17] The full report "**Market response study 2017**" will be made available as soon as possible at http://www.elia.be/en/users-group/Working-Group_Balancing/TF_Strategic_Reserves_Implementation/Agenda

[18] In general, DSR is seen as the reduction of consumption (not including generation or storage technologies), while MR should be understood in a broader sense making abstraction of the technology (including generation or storage technologies).

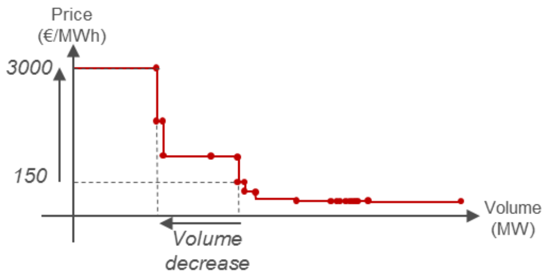

Figure 27: market response in the demand curve

On the demand side, the output is the volume of market response for each given hour.

As an example, if 400 MW are above the limit of 150€/MWh, the estimated volume of market response for that particular hour is estimated to be 400MW.

5.6.1.2 Offer increase

Instead of a demand decrease, suppliers can value market response as a new offer in the market. This volume would appear in the supply curve. These curves cannot be analyzed as such since they may not only integrate only demand behaviors. Indeed, contrary to demand curves where the presence of bids representing generation is very limited above 150€/MWh, the supply curves can integrate this type of bids. Indeed, generation bids higher than 150€/MWh can be justified by extraordinary variable costs like, for example, a foreign sourcing.

To refine the analysis of the supply curve, we consider two price thresholds:

- **150€/MWh**: it is generally considered as the limit bid for generation assets, even if some generation assets can justify higher bids in specific cases
- **500€/MWh:** Above this value, it is considered very difficult to justify the price, and we can consider that only demand response bids appear in the curves

The analysis of the supply aggregated curves indeed provides us a range with:

- **a low estimation** of the offer side: this estimation doesn't take into account the potential value under 500€/MWh but definitely excludes generation
- **a high estimation**: this estimation integrates the adequate market response perimeter but possibly takes into account additional volumes of generation assets

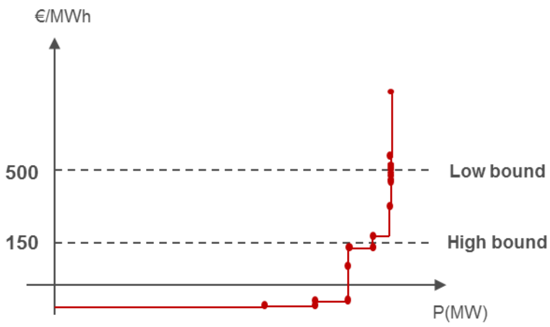

Figure 28: analysis of the supply aggregated curve

In the aggregated curves, the smart orders[19] are not taken into account. This reduces the total volume estimated. Though, the volumes of Market Response smart orders are very limited, most of it being from generation assets. The impact for the Market Response volumes assessment is very limited.

The OTC bids are implicitly taken into account in the curves. If not in the curves, it would correspond to irrational behavior of the stakeholders, which is not to be taken into account in this study.

As an example, if the volume above 150€/MWh is 150MW and the volume above 500 €/MWh is 100MW, it can be considered that the volumes of Market Response valued in the supply curve will be in the range [100-150] MW.

The output volume of the methodology will indeed correspond to the adapted perimeter for the contract based and price based MR categories, but also the voluntary MR foreseen by the BRPs. Indeed, if there are some volumes in the voluntary MR category, the BRPs will anticipate such events. In theory, their anticipation will be reflected in their bidding behaviors if they are considered as firm by the BRPs, voluntary MR being then implicitly taken into account in this methodology.

5.6.2 "Objective qualitative Q&A": qualitative content to complement the aggregated curves analysis

The aggregated curves analysis provides a capacity estimation and not an hourly volume to integrate in the model. For the integration into the adequacy assessment of Elia, it is required to obtain the number of activations per week and the maximum activation duration.

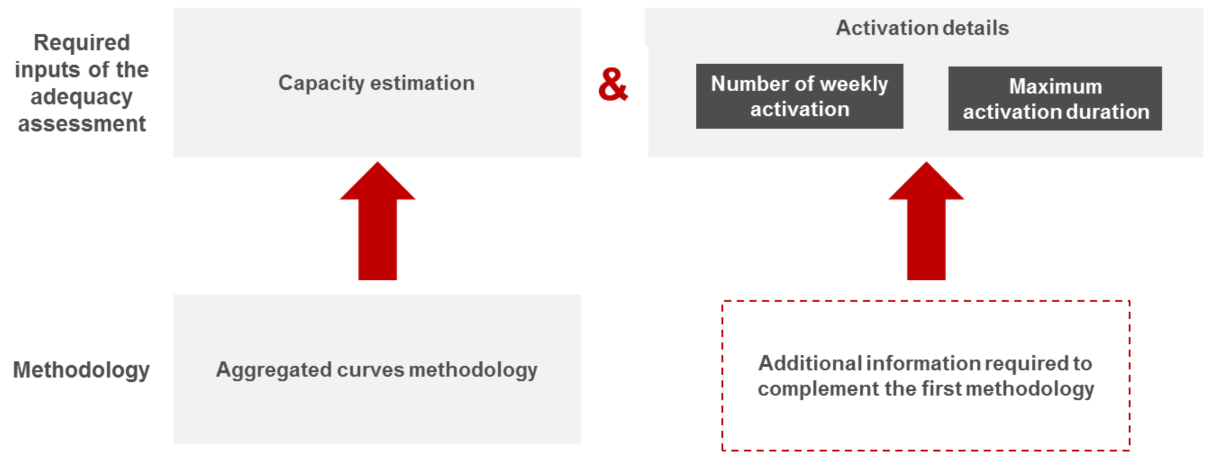

Figure 29: integration of the methodology into the adequacy assessment

The details on the activation will be obtained by means of a Q&A. This questionnaire will be **objective**, to avoid unrealistic and non-answerable questions. It will also be **qualitative**, focused on gathering the required information on the activation in order to establish a correct link between the adequacy and the methodology, i.e. the activation details.

According to the discussion conducted with the stakeholders, the Q&A must be simple, intuitive, and have questions anchored in the reality. Its main objective will be to obtain qualitative

[19] Smart orders are linked block orders (one block is executed if the other is also) or exclusive block orders

information to complement the aggregated curves methodology. The key information being the number of possible activation per week and the duration of the activation.

A specific questionnaire will be developed for each type of player (suppliers, aggregators and customers), in order to take their specificities into account. The questionnaire will be developed in close cooperation with the respondents so as to ensure useful answers.

5.6.3 Global sanity check

To conduct a sanity check, the questionnaire can provide an estimation of the volumes currently valued. This would enable to avoid the main limit of the questionnaire raised by the stakeholders: the hypothetical situation description.

An international comparison point will also be formalized, putting the market response volumes in proportion of the maximum peak load in the electric system.

These volumes will then be compared to the volumes previously established so as to assess the global coherence of the volumes.

5.6.4 Integration in the adequacy assessment

The output of the aggregated curve analysis will be hourly values of Market Response volumes. To integrate the results in a pertinent manner into the adequacy assessment, the statistical distribution of the results will be analyzed to provide confidence intervals and go beyond a simple average calculation. The impact of different parameters will also be assessed to reveal specific patterns, if present. The impactful parameters could be the day types (week day vs weekend), the time (peak hours), the temperature or the season. If specific patterns appear, they will be taken into account when integrating the results in the adequacy assessment.

Also, the methodology should provide volumes estimation for the three following winters. The output of the methodology, valid for next winter, will indeed be extrapolated based on the evolution of Market Response volumes during the three previous years, provided by the aggregated curves analysis. This extrapolation could also be validated by inputs provided by the qualitative questionnaire. Also, a correction factor will be applied due to the volumes of ancillary services. This correction factor will be based on the projections of ancillary services needs, conducted by Elia and on the historic MR contribution.

The methodology will then provide a volume estimation of Market Response for the three following winters.

6 Appendix

6.1.1 How does flow-based work in reality?

The flow-based method implemented in day-ahead market coupling uses Power Transfer Distribution Factors (PTDF) factors that make it possible to model the real flows on the lines based on commercial exchanges between countries. PTDF[20] division factors allow to estimate the real flow that are to be expected in the different grid lines/elements as a function of the commercial exchanges to be settle in the market between countries. The example in Figure 16 above shows that energy flows are unevenly distributed over the different paths between the different areas considered when there is a commercial exchanges 100 MW considered between A and C areas. The PTDF factors of this example determine that:

- **75% of the injection from A goes to B and 25% of the injection from A goes to C**
- **65% of the injection from B goes to C and 10% of the injection from B goes to D**
- **Finally the total injection coming into C is 25% + 65% = 90% which goes to D**

Since the commercial exchange of 100 MW is a between A and D in the case above, exchange (A→ D), the PTDFs for each grid lines/elements is referred as $PTDF_{(A \rightarrow D)}$:

Commercial Exchange (A → D)	Grid Element 1	Grid Element 2	Grid Element 3	Grid Element 4	Grid Element 5
$PTDF_{(A \rightarrow D)}$	25%	75%	65%	90%	10%

A matrix of exchanges vs grid elements can be therefore defined (only A → D numbers shown for simplicity)

PTDF	Grid Element 1	Grid Element 2	Grid Element 3	Grid Element 4	Grid Element 5
$PTDF_{(A \rightarrow B)}$	-	-	-	-	-
$PTDF_{(A \rightarrow C)}$	-	-	-	-	-
$PTDF_{(A \rightarrow D)}$	25%	75%	65%	90%	10%
$PTDF_{(B \rightarrow C)}$	-	-	-	-	-
$PTDF_{(B \rightarrow D)}$	-	-	-	-	-
$PTDF_{(C \rightarrow D)}$	-	-	-	-	-

For each hour of the year, the impact of energy exchanges on each critical element (also called critical 'branch' and/or critical 'outages') is calculated taking into account the N-1. A critical 'branch' is a physical element of the grid line/element, which has reached its maximum transmission capacity and therefore constrains the total flow of the system around it.

[20] PTDF: Power Transfer Distribution Factor

Typically energy exchanges lead to many constraints. Those constraints form a domain of possible maximum energy exchanges between the CWE countries (this is called the flow-based domain).

Looking at the system above, and e.g. at the possible commercial exchanges between $A \rightarrow B$ and $A \rightarrow C$, the basic equation defining **the condition <u>of each of the interconnections</u> in the system above as critical branch** is given by the following type of equation.

<u>For each of the 5 interconnections shown above</u>:

$$PTDF(A \rightarrow B) * Exchange(A \rightarrow B) + PTDF(A \rightarrow C) * Exchange\ (A \rightarrow C) \leq RAM$$

, where RAM is the Remaining Available Margin (RAM) of each line.

Each CB can be drawn on the plane defined by the relevant exchanges between any two areas of the system considered (in this case the plane of $Exchange(A \rightarrow B)$ vs $Exchange(A \rightarrow C)$ **<u>as a line</u>** (each of the dotted lines in Figure 1 below). The set of all CBs relevant for the $Exchange(A \rightarrow B)$ vs $Exchange(A \rightarrow C)$ plane defines a polygon (connected grey lines) or so-called FB domain, as depicted schematically in the Figure 2 below. The coloured squares in correspond to the so-called Available Transfer Capacity (ATC) domains, which provide the Available Transfer Capacity considering long-term nominated power flows and NTCs in a traditional NTC non flow-based scheme.

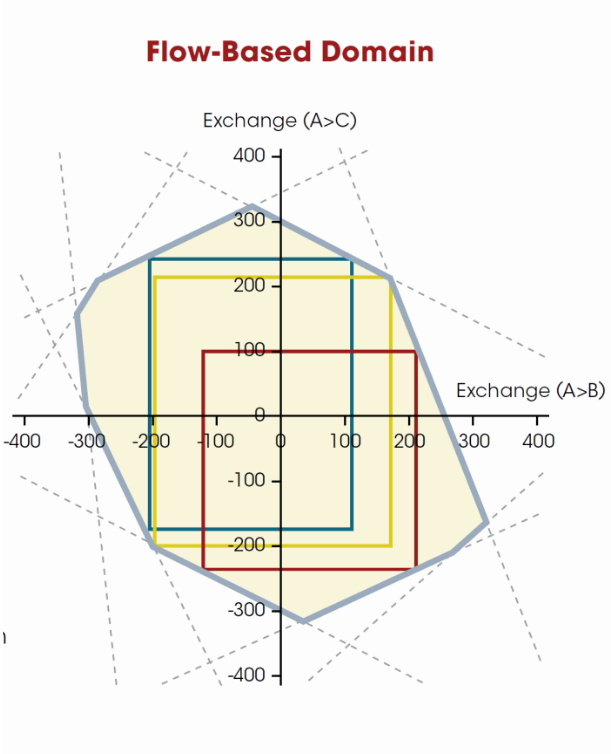

Figure 30 Example of flow-based domain (see CWE Flow-Based [18])

These flow-based domains are typically constructed based on 'critical branches' (lines or grid elements – hereafter referred as CBs), taking account: 1) the impact of an outage on these CBs, 2) a flow reliability margin (FRM) on each CB and possibly 'remedial actions' that can be taken after an outage to unload part of the concerned CB.

Those actions make it possible to maximise exchanges thanks to changes in the topology of the grid or the use of phase shifting transformers. The various "remedial actions" that are used to form these domains are typically coordinated and approved by the other TSOs in the framework of the Regional Coordination Centre Coreso. It is important to note that Elia has no guarantee that the other TSOs will always be in a position to accept these "remedial actions" in situations where Belgium is facing a risk of structural deficit, such these other TSO also face risk of structural deficit simultaneously to BE.

The domains are assessed in a full availability state of the grid since no planned maintenance are scheduled during the winter period. However, unforeseen outages are always possible and could affect the domain and the available capacity between the CWE countries

Different assumptions are made for the calculation of these flow based domain, such as the expected renewable production, consumption, energy exchanges, location of generation, outage of units and lines, etc.

For every hour there might be a different flow-based domain because:

- the topology of the grid can change;
- outages or maintenance of grid elements can be scheduled or happen;
- the location of available production units can vary significantly from hour to hour.

The flow-based domain is calculated two days before real-time operation and is used to define the limits of energy exchange between countries for the day-ahead market.

6.1.2 The N-1 security criteria of the grid

The interconnection capacity takes into account the reserve margins that transmission system operators must maintain to follow the European rules ensuring the security of supply. The loss of a line or a grid element can occur at any time. The remaining lines have to be able to cope with the increased electricity flow due to any outage.

In technical terms, this is called the N-1 rule: for a given number N of lines that are transporting a given amount of energy, there cannot be an overloaded line in case of the outage of one of the lines. The flow-based domain is calculated taking into account all possible N-1 cases.

Note, however, that European rules stipulate that this criterion has to be fulfilled at each moment, including in the event of grid maintenance or grid repair work. In such cases, it is possible that the import capacity has to be reduced. Wherever possible, maintenance and repair work is avoided during the most critical periods, e.g. around the peak consumption times of the year, but cannot be ruled out, especially after winter weather conditions. The representative flow-based domains used in this study do not cover such situations of grid maintenance.

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