Public consultation on the methodology, hypotheses and data sources for the dimensioning of the volumes of strategic reserve needed for winter 2021-2022

Consultation period:

From 03/06/2020 to 01/07/2020

Contents

1 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' – for more information on the legal framework see Appendix A). The analysis by Elia concerns the need for the winter 2021-22 and an indication for the winters 2022-23 and 2023-24 (note that the mechanism is only approved until winter 2021-22).

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.

1.1 Structure of this document

This document aims to provide 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.

As this is the eighth iteration of the strategic volume need determination, both law and methodology have been refined and become stable. Therefore, this document has been restructured, moving more general descriptions to the appendices whilst focussing on changes & improvements in the main text.

This main text is divided into two parts:

- The first describes the methodological changes;
- The second provides an overview of the main hypotheses and data sources that are proposed to be used for the analysis.

Additionally the methodology for market response developed by E-Cube and the methodology for the short-term consumption scenario by Climact will be both attached as separate documents.

1.2 Timing

This document is published on Elia's website from **June 03, 2020** onwards. The different reactions from stakeholders should be addressed via the form on the link of the public consultation;

Stakeholders have a period of four weeks to provide their various comments. The reactions should be sent at the latest by **July 01, 2020 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 and will also be explained in the Task Force "Implementation of Strategic Reserve".

It is important to note that all the non-confidential comments received will be published at the end of the consultation.

1.3 Subsequent consultations

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.

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.

2 Methodology

The methodology and assumptions are based on the latest published European adequacy assessment performed by ENTSO-E. Some of the elements of this methodology were further improved by Elia.

2.1 Improvements

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. As this concerns the eighth iteration of the volume determination, the methodology and assumptions have become quite stable.

Nevertheless, some methodological improvements in the assessment for winter 2021-22, compared to the assessment performed for winter 2020-21 are foreseen.

Here below, an overview of the main improvements and its related documentation:

2.1.1 Flow-Based modelling

To build market models where market exchanges adhere to the rules depicted in a flow-based coupled market, multiple approaches are possible. For short-term forecasts and analyses, a framework relying on the flow-based domains conceived in the SPAIC process was developed [2]. This framework however leans heavily on historical data. Elia has therefore developed a flow-based framework which does not rely on historical domains, but instead aims to mimic the operational flow-based capacity calculation workflow, for which the required inputs are forecasted for the targeted time horizon. As the market design and rules are expected to change considerably, Elia prefers this flow-based framework over the SPAIC domains as this framework does not rely on historical flow-based data and allows mimicking the foreseen market condition for a target horizon. This framework was already used in the 10-year Adequacy and Flexibility study 2020-30 [1] and created domains were re-used by the latest PentaLateral Energy Forum (PLEF) Generation Adequacy Assessment (GAA) report that was published in May 2020.

For a more in depth explanation on flow-based modelling, please refer to Appendix C.

2.1.2 Total Demand Growth

Over the past few years, Elia relied on forecasts provided by IHS Markit (CERA) for the domestic total demand growth rate for Belgium. Given several comments received in the past in the framework of the strategic reserve volume evaluation, Elia took the initiative to improve the demand forecasting process by developing a methodology/tool in collaboration with Climact. This new methodology aims to be more detailed, transparent and better integrate policy/macro-economic changes in the demand forecasting process. The "Total Electricity Demand Forecasting" project was introduced to stakeholders in the beginning of 2020, the final methodology proposal for the consumption scenario was presented on the 02/06/2020.

For a more in depth explanation on the demand forecasting methodology, please refer to the attached document "Total Electricity Demand Forecasting".

2.1.3 Market Response

In the context of the strategic volume determination analysis for winter 2018-19, key market stakeholders agreed upon a design for the most adequate methodology to determine the volumes of Market Response in Belgium.

Upon request from stakeholders, the methodology has been be adapted to cope with multiple NEMO as well as complex bids.

For a more in depth explanation on the market response evaluation, please refer to the attached document "Market Response Methodology".

3 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 2021-22. The hypotheses and data sources are in line with the European methodology developed and the data gathered from the latest Mid-Term Adequacy Forecast study [9].

Section 3.1 focuses on the general hypotheses and data sources, while section 3.2 provides the details for Belgium in specific. The hypotheses and data sources for the other countries considered in the analysis are given in section 3.3.

3.1 General hypotheses and data sources

3.1.1 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 21 different countries, is shown in Figure 1.

Figure 1

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), Poland (PL) and Finland(FI).

3.1.2 Climatological data

Climatic variability is modelled using historical climate data of 34 historical winters. The concerned winters are those between 1982 and 2016. Data related to hydro inflows, irradiation, wind speed and temperature among others are consolidated in the ENTSO-E Pan-European Climate Data set (PECD). This study will be based on the latest published methodology and data from the MAF study[9].

3.1.3 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 [6]('Electricity Act', translated from Dutch):

"***Winter period***": *period from 1st of November until 31st of 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. 2021-22. 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. 2022-23 and 2023-24. The different indicators will be calculated for these periods.

3.1.4 Base case and sensitivities

The base case will be developed with the hypotheses and data sources as they are described in this document. For the sensitivity Elia will use a "low probability – high impact" scenario, this scenario was approved by the European Commission's DG Energy within the context of a state aid review of the strategic reserve mechanism [4]. An historical analysis will determine the amount of generation volume that should be considered unavailable in Belgium & France (although other countries or events could be considered, if relevant).

3.2 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 3.2.1**, the data sources and modelling techniques used with regard to **Belgian electricity supply** are detailed. Next, **section 3.2.2** 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 2020 (this step will happen earlier so it can be submitted to public consultation end of August). The information received from the FPS Economy will be integrated in the report and will be taken into account in the analysis.

3.2.1 Hypotheses on the Belgian electricity supply

3.2.1.1 Onshore wind, offshore 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. The forecasts for installed capacity are combined with the historical production profiles to obtain 34 different time series for the winter period and for onshore wind, offshore wind and photovoltaic production separately. This process is illustrated in Figure 2.

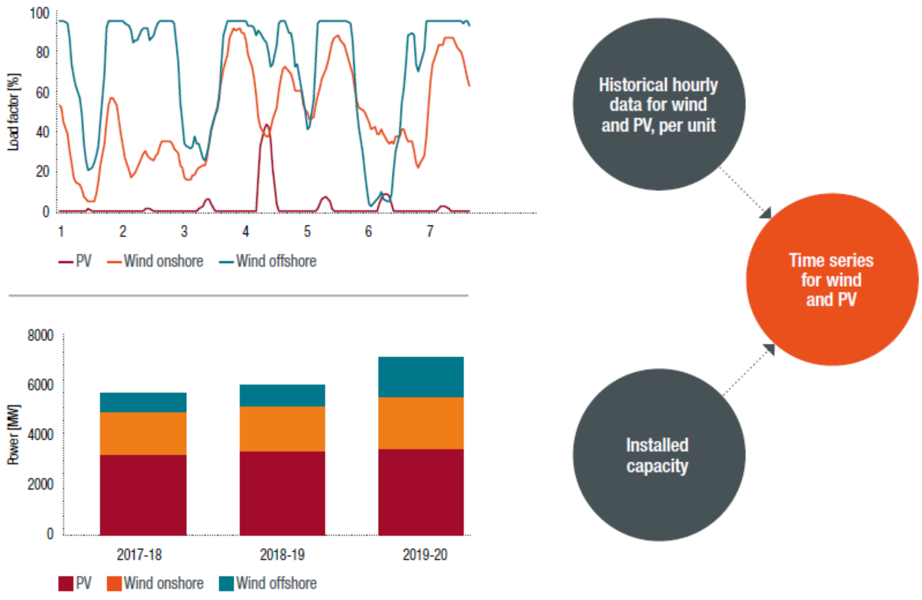


Figure 2

3.2.1.2 Biomass, waste, combined heat & power facilities and small production units

Installed capacity consolidation

In the same way as for onshore wind and PV, the FPS Economy will consolidate a forecast for the installed **biomass** production capacity after consultation with the regions.

For **CHP, waste**, and smaller production units 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.

<u>Elia generation database</u>

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[1] 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, often units with an installed capacity smaller than 0.4 MW are also reported, either individually or aggregated. The database contains both information concerning units that are in service, but also projects that are currently under development.

[1] 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.

Modelling approach

In the ANTARES model, production units subject to a CIPU contract are modelled differently from those for which no CIPU contract applies.

The thermal production units with a CIPU contract are discussed more in detail in section 3.2.1.3.

For non-CIPU thermal production, an extensive analysis was done to identify the main drivers for their production profile. It was shown that the output of these units (green house CHP's, public building heating CHP, process heating …) was closely correlated to the outside temperature. Additionally, very little difference in behaviour was found when looking at fuel type (biomass, waste, gas …). Therefore, these units were combined into a single, more resilient, category with a temperature-dependant production profile. For this year's analysis, the same approach will be applied for the non-CIPU thermal units.

3.2.1.3 Thermal production with a CIPU contract

Installed capacity of the thermal production with a CIPU contract

The installed capacity of the Belgian thermal production fleet 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 of **nuclear** electricity production will be aligned with the law on the nuclear phase out (latest version).

Modelling approach

Thermal units under CIPU contract are modelled as individually dispatchable units. Additionally, more complex technical characteristics, such as outage rates, must run obligations, minimum up & down times are taken into account (but those do not impact the adequacy results).

Availability of the thermal production with a CIPU contract

The individual availability of each CIPU unit is determined by a probabilistic draw for each 'Monte Carlo' year, 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**

As was done last year, the latest available data on planned outages from the transparency websites of the generation unit owners will be taken into account for Belgium. This will be incorporated into the model for winter 2021-22. For the subsequent winters 2022-23 and 2023-24, no planned outages information is available, therefore, no maintenance will be considered in the course of those winters.

- **Unplanned unavailability**

On top of the planned unavailability this study will take into account unplanned or forced unavailability. Each year, the analysis is updated for each production type (e.g. CCGT, gas turbine, turbojet...), based on the historical unplanned unavailability incorporating the latest data. These updated unplanned unavailability rates will be communicated in the input consultation of this summer.

Furthermore, "low probability, high impact events", as observed during the last winters, need to be considered in a scenario on Belgian and French nuclear availability (note that other events could be considered as well if relevant). This approach has been agreed upon by the EC (DG competition [1]) to be used as 'dimensioning' scenario for the strategic reserve volume.

3.2.1.4 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 Plate 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, and notably the Black-start service. 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 therefore 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. When the model encounters periods of structural supply shortage, 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 will be taken into account in the model by using 34 historical profiles relevant for the winter period. Elia will update the installed capacity of the run-of-river power stations taking into account the information received from the FPS Economy.

3.2.1.5 Balancing reserves

In the context of its legal obligations, Elia is obliged to contract ancillary services to ensure a secure, reliable and efficient electricity grid [7]. As part of the ancillary services, the 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 restoration reserves is taken into account in the simulations as a reduction of available capacity to cope with adequacy (the reserve requirements for BRPs that have production units which a capacity larger 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 amount of reserves to be used in the context of this study will be included.

3.2.2 Hypotheses on the Belgian electricity demand

3.2.2.1 Process for constructing demand curves

The hourly total electrical load is forecasted for the next three winters. This is done for all the simulated countries. The construction process can be divided in 3 steps as shown in Figure 3.

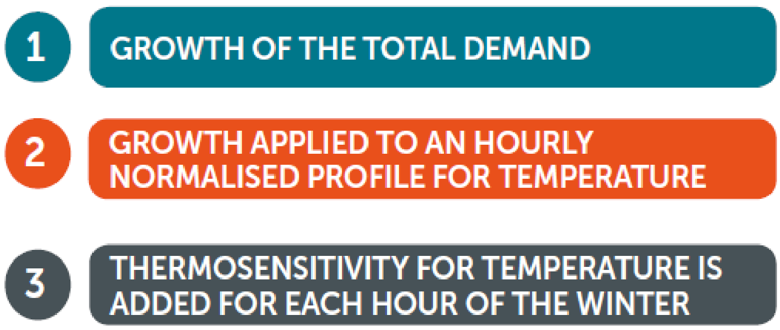


Figure 3

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

The total electrical consumption takes into account all the loads on the Elia grid 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 as a separate load connected to Belgium.

What is published on Elia's website?

Two load metrics 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 [8]

3.2.2.2 Growth in total Belgian load

The first step consists in forecasting the yearly total electrical demand for a given country. After the normalisation of the total demand 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). Over the past few years, Elia has worked with the IHS MARKIT consultancy bureau as the data provider for the domestic demand growth rate.

As stated in the introduction, taking into account several remarks made by stakeholders, Elia took the initiative to improve the demand forecasting process in collaboration with Climact. This new methodology aims to be more detailed, transparent and better integrate policy/macro-economic changes in the demand forecasting process.

3.2.2.3 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 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 2020-21 is shown in Figure 4 by means of example.

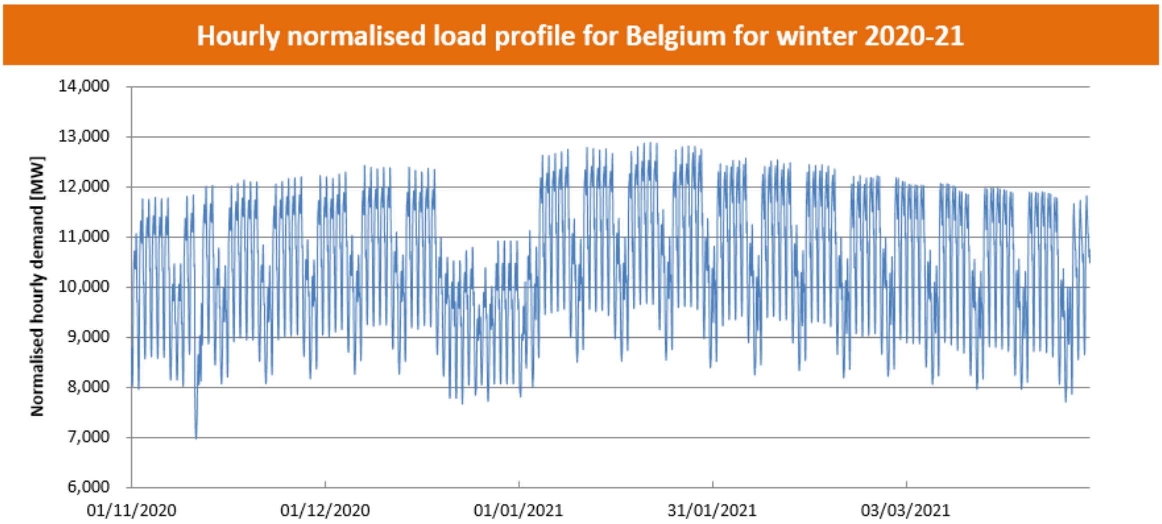


Figure 4

From Figure 4 one can clearly see the effects of week/weekend and the holiday effect (around New Year) 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 higher peak consumptions in case of lower temperatures.

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.

3.2.2.4 Sensitivity of the load to temperature

The last step consists in applying the temperature sensitivity to the hourly normalised profile. For each of the 35 historical climate years, an hourly profile for consumption is created. This will allow the analysis to be carried out using 34 different hourly load profiles for the analysed winters.

Up until today, this operation was performed using an application developed by ENTSO-E. This application, applied in many studies such as MAF, PLEF, etc., uses a cubic relationship between temperature and load, in contrast to older, linear models.

Last year ENTSO-E introduced a new way of creating the final load profiles for the various climatic years for all European countries. This software is called TRAPUNTA and will be used in Elia's studies in order to keep consistency with the European adequacy assessments.

3.2.3 Market response

As agreed in the context of the "Implementation Strategic Reserve" task force during 2017, and to take into account the future evolutions of the Market Response volumes, quantification of the volume will be updated yearly, in order to obtain most 'up-to-date' representative results every year. This assessment will therefore be rerun, including the methodology improvement allowing to cope with multiple NEMO as well as complex bids.

For a more in depth explanation on the market response evaluation, please refer to the attached document "Market Response Methodology".

3.3 Hypotheses for the other simulated countries

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

3.4 Hypotheses for interconnectors

The interconnections have been modelled as they are used in the day-ahead market coupling mechanism. The countries within the flow-based perimeter are therefore modelled using the flow-based (FB) methodology (more detail in Appendix C). 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 flow-based perimeter, the interconnectors will be modelled on the basis of values of the bilateral 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.

3.4.1 Flow-based domains

Belgium is currently electrically interconnected to France, the Netherlands, Great-Britain (through Nemo Link®) and Luxembourg (part of the Elia control zone for the Sotel/Twinerg grid).

By winter 2020-21 also the ALEGrO HVDC interconnector with Germany will be operational.

In order to comply with the Clean Energy Package and to fully assess the adequacy situation of Belgium, given these changes, a flow-based framework has been set up, which is described more in detail in Appendix C. Additionally, the same systematic approach as used in previous assessments will be followed, linking specific combinations of climate conditions for wind and load with the representative flow-based domains to be considered in the simulations.

3.4.2 FB domain impact related to the evolution of the 380kV grid in Belgium

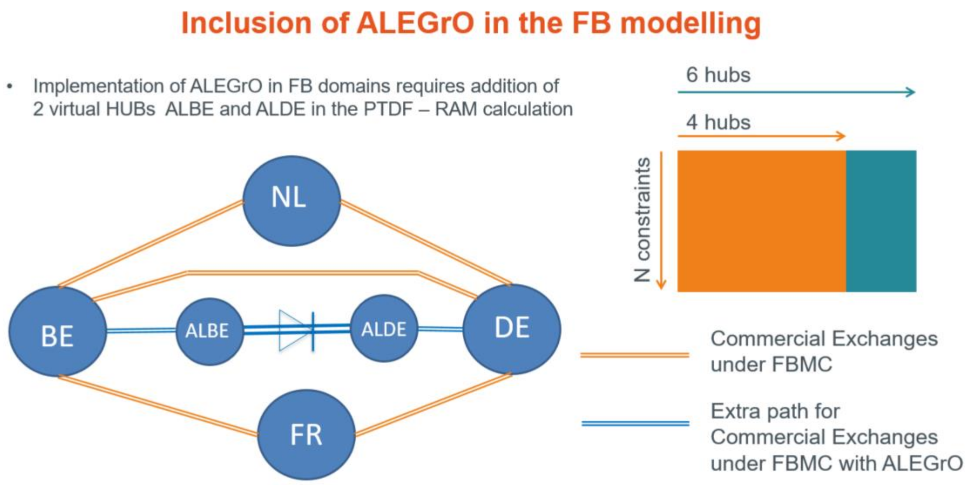
The following considerations regarding upcoming investments in Belgium’s 380kV grid will be taken into account in the assessment of the volume for strategic reserve:

3.4.2.1 NEMO Links ®

The Nemo Link® HVDC connection came online early 2019. As was done last year, this interconnector with Great Britain will be taken into account for all winters in the assessment. This interconnector will be modelled as an NTC link.

ALEGrO

The planned HVDC interconnection with Germany (ALEGrO project [10]) will also be considered for winter 2021-22 in this assessment.



3.4.2.2 Evolution simultaneous import capacity restriction

Taking into account NEMO & ALEGrO a simultaneous import capacity restriction of 6500 MW over all Belgian borders is defined and applied in capacity calculation. This limitation is applied to ensure adequate voltage regulation capability of the Belgian system at high import levels.

It is important to note that adequacy-related issues in Belgium mainly arise when both Belgium & France are in simultaneous scarcity. In these situations, the import levels that Belgium can obtain in the market do not reach the maximal import restriction. In other words, generally the binding CNEC in adequacy stress situations is not the external constraint.

3.4.2.3 HTLS upgrades (Avelin-Avelgem-Horta & Horta-Mercator)

The classic AMS conductors (Aluminium-Magnesium-Silicon) will be replaced by high-performance HTLS conductors (High Temperature Low Sag) for these parts of the 380kV grid. The latter type has a higher transport capacity and sags less. Evolutions of the HTLS deployment will be followed in the assessment for each of the considered winters. Changes to the historical domains will be applied when relevant in order to consider the increase in capacity that these upgrades will bring.

3.4.3 HVDC outages

Availability of the HVDC system elements will be included in the simulation as random outages.

Random outages are represented by the parameter Outages Rate (OR), which in this case defines the annual rate of outage occurrences of HVDC lines. Those situations are simulated by random occurrences of outages within the probabilistic Monte Carlo scheme, while respecting the annual rate defined.

An average unavailability rate for each HVDC interconnector will be used as benchmark value, following the latest ENTSO-E's MAF report. It should be noted that this value includes both unexpected outages of HVDC lines as well as planned outages of interconnectors. This assumption is relevant for the adequacy assessment, since the focus is on considering the impact of availability (planned or unplanned) of interconnectors on adequacy.

Additionally, it should be noted that new assets do not necessarily show lower outage rates. A good example of this is the bathtub curve, which is widely used in reliability engineering as a model for asset reliability by age. This curve starts off with an early failure section.

3.4.4 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 [11].

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[2] 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), Poland (PL) and Finland (FI).

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.

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

Appendix A Legal framework and process

A.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 5):

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[3] 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.*

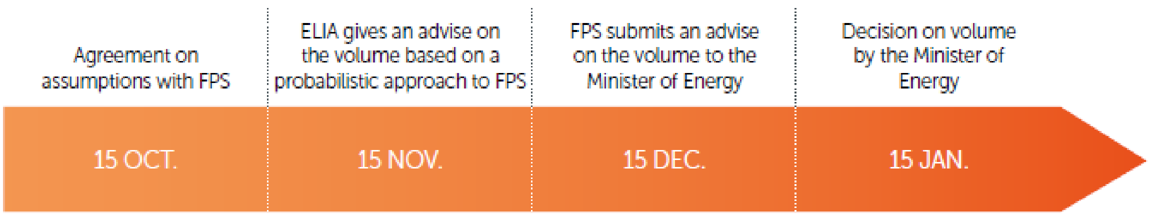


Figure 5

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:

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

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.*

A.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.'

A.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 6). The model Elia uses for the probabilistic assessment enables the calculation of both indicators.

LOLE < 3 hours

LOLE95 < 20 hours

Figure 6

- *"**LOLE**[4]": 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[5], even taking into account interconnectors, for a statistically normal year.*
- *"**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, for a statistically abnormal year[6].*

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[7]) and generation capacity (SGR[8]):

- 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).

[4] LOLE: Loss Of Load Expectation

[5] Load: Demand for electricity

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

[7] SDR: Strategic Demand Reserve
[8] 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.

Appendix B Proposed methodology

The volume of strategic reserve is determined in three steps. 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 based on historical data regarding meteorological conditions (wind, sun, temperature, precipitation) and power plants' unavailability.

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[9] 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.** An iterative process is used to determine the total strategic reserve volume.

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

Figure 7

B.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.

B.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.** These correlations are captured by use of synchronized hourly time series, namely:

- hourly time series for **wind energy generation;**
- hourly time series for **PV**[10] **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.

---

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

[10] PV: photovoltaic

- 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.

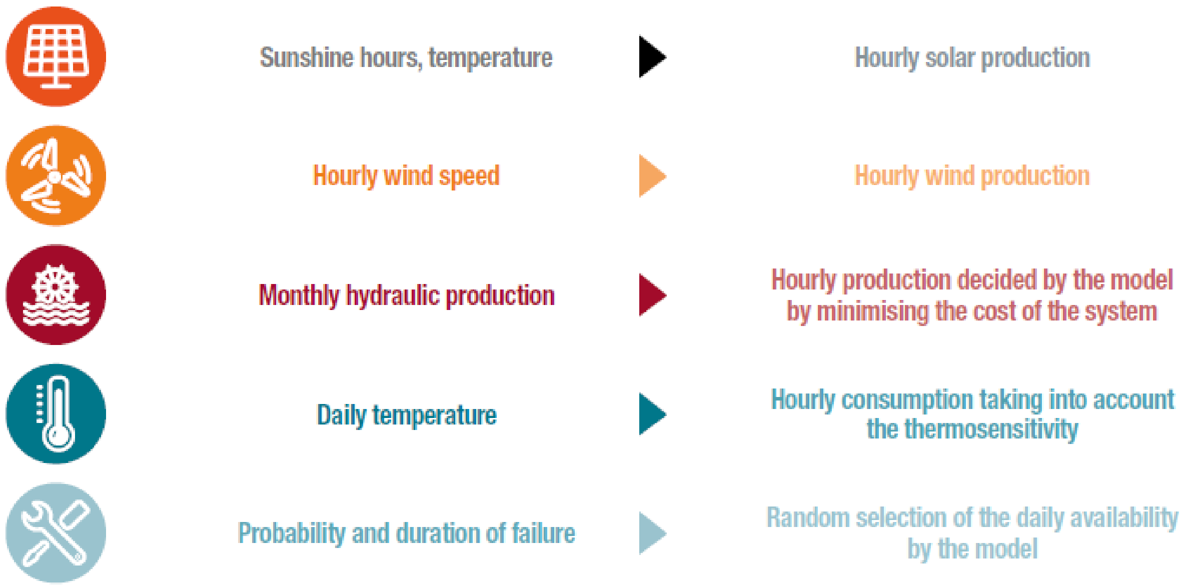


Figure 8

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.).

B.1.2 'Monte Carlo' sampling and composition of climate years

These variables 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.

Figure 9

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.

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.

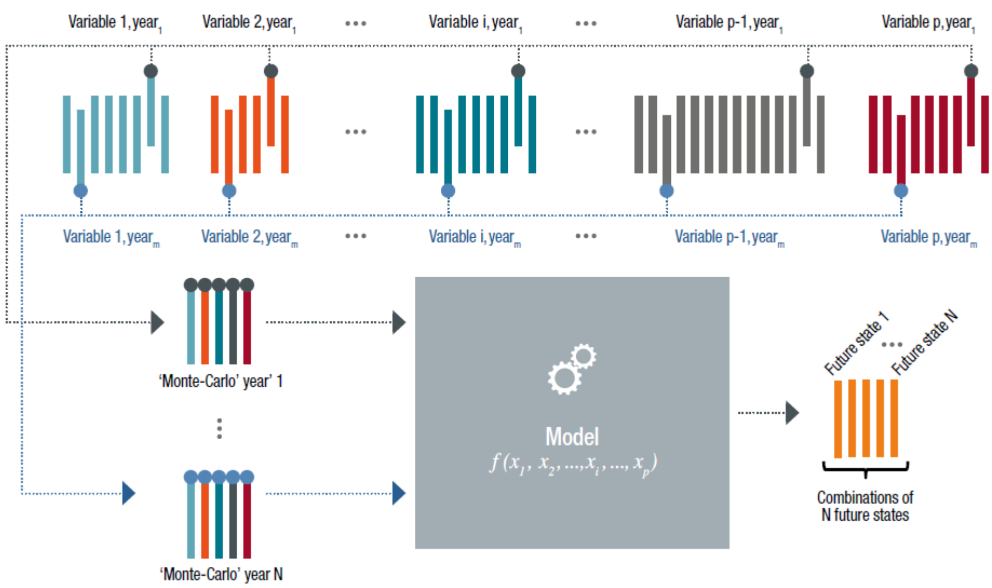


Figure 10

B.1.3 Number of future states

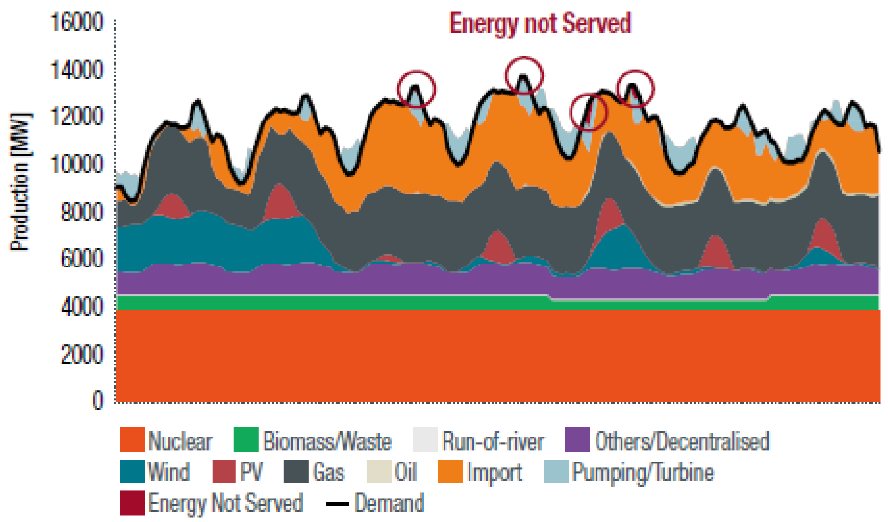
The number of future states that need to be calculated by the model to ensure the convergence of the results depends, among other things, on the variables, the simulated perimeter and the variability of the generation facilities. For the volume determination of strategic reserve the focus is on the two 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.

Hundreds of future states are required to achieve convergence of the indicators. This means that all 34 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.

B.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 11 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 11 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 11

B.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.

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 12). Using the economic dispatch enables the pumped-storage power plants and hydroelectric reservoirs to be appropriately modelled (see section 3.2.1.4).

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. Additionally, market response to high prices is also taken into consideration.

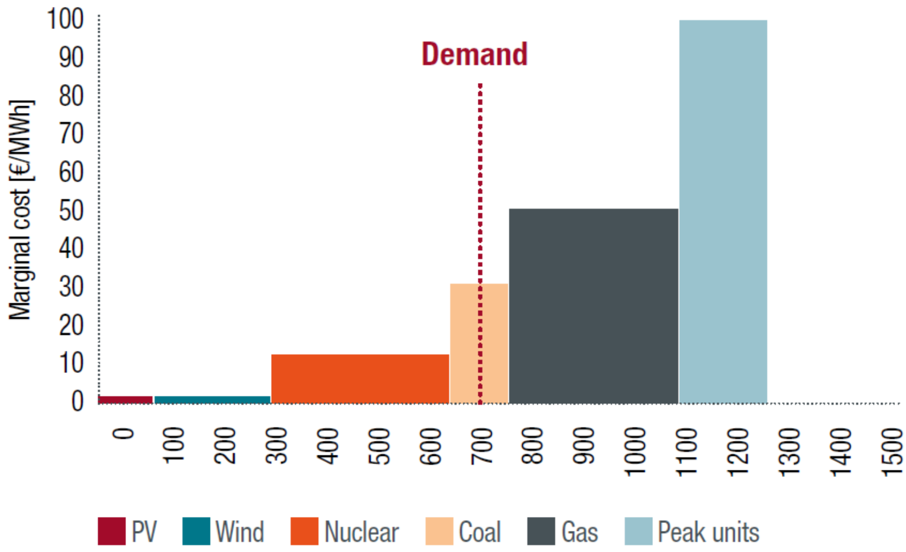


Figure 12

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 13 represents a schematic overview of the model's input and output.

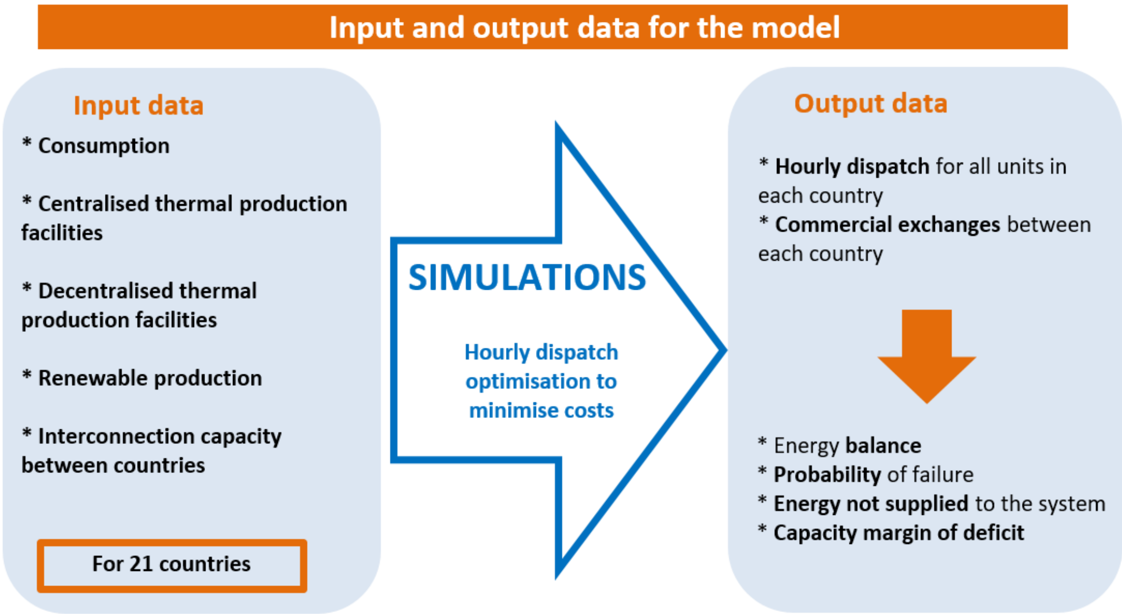


Figure 13

B.2.2 Model used to simulate the electricity market

The market simulator used in the scope of this study is ANTARES[11], 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.

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

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. The main process behind ANTARES is summarised in Figure 14.

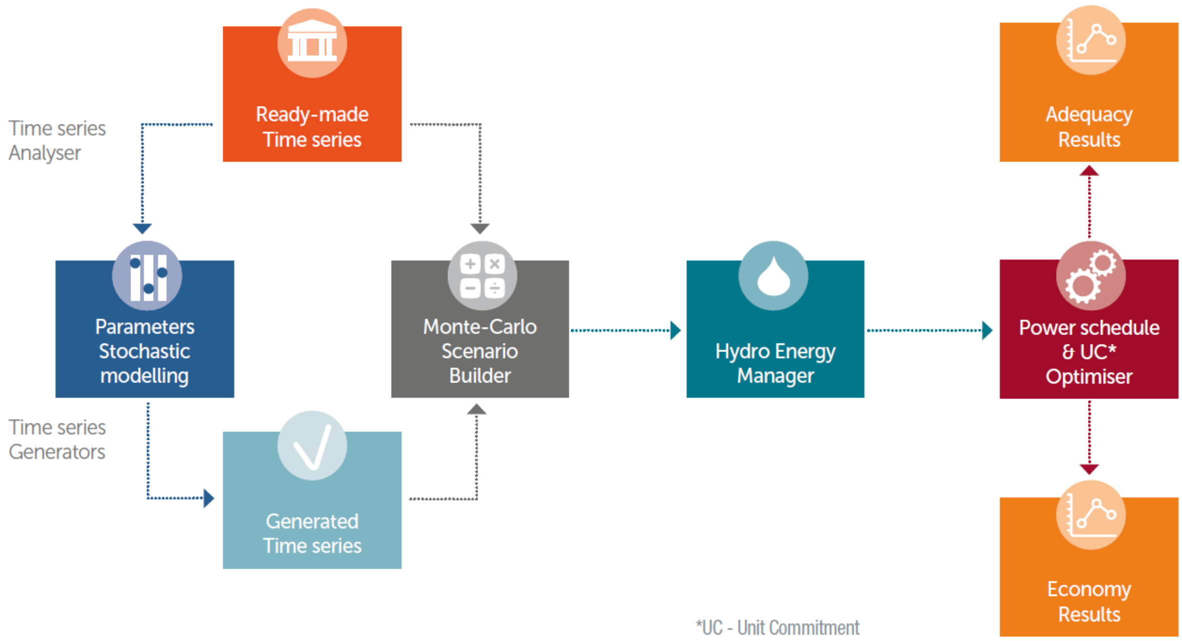


Figure 14

The model is used in many European projects and national assessments such as the PLEF adequacy study, the RTE French Generation Adequacy Report, the TwenTies project, e-Highway2050, ENTSO-E's TYNDP[12], ENTSO-E's MAF and many more;

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

[12] TYNDP: Ten Year Network Development Plan

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.

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.

B.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 15). 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 hundreds of future states.

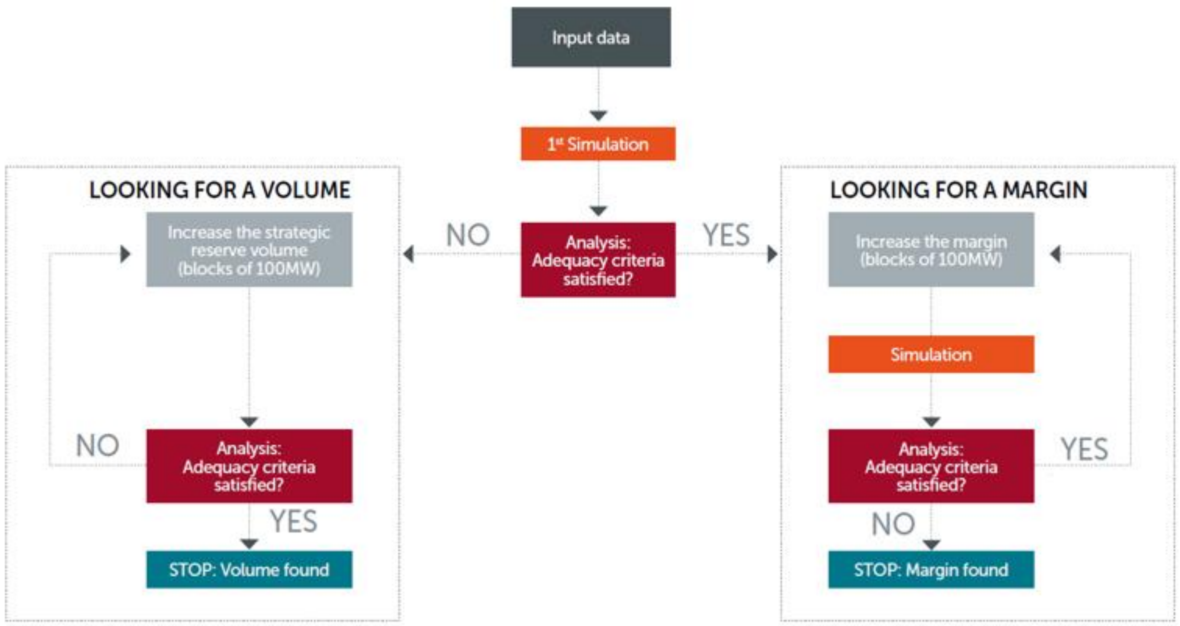


Figure 15

Appendix C Flow-based method applied

C.1 Why use a flow-based methodology?

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 exchange capacities at the borders.

Market simulation tools and methods are being 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.

As Belgium is in the COREMOD flow-based perimeter (see Section C.2.2), the country's import and export capabilities at the day-ahead timeframe 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 flow-based perimeter 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 16 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).

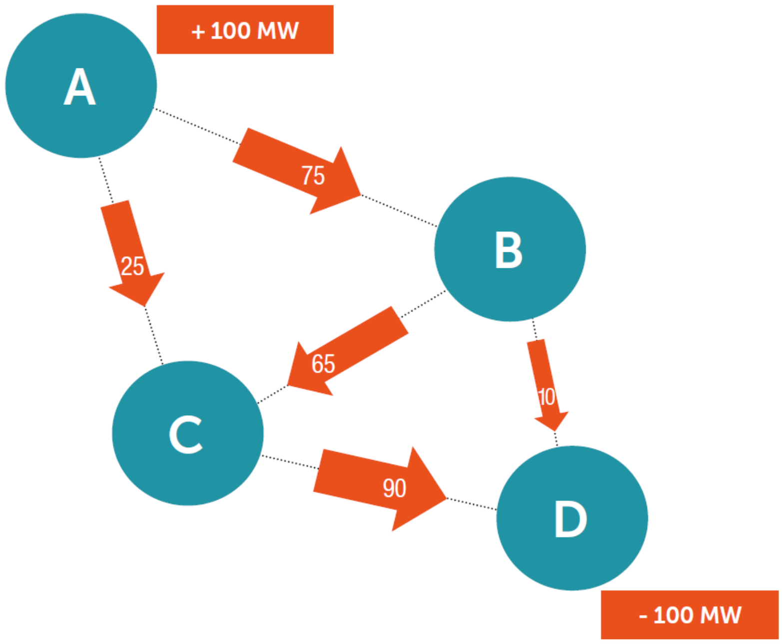


Figure 16

C.2 How are flow-based domains established?

As described in the previous section, the flow-based capacity calculation is a complex process involving many parameters. To build market models where market exchanges adhere to the rules depicted in a flow-based coupled market, multiple approaches are possible. For short term forecasts and analyses, a framework relying on the flow-based domains conceived in the SPAIC process was developed [2]. This framework however leans heavily on historical data, and becomes more complex and less accurate when multiple parameters and inputs are expected to change between the historical data and the targeted time horizon. Elia has therefore developed a flow-based framework which does not rely on historical domains, but instead aims to mimic the operational flow-based capacity calculation workflow, for which the required inputs are forecasted for the targeted time horizon.

C.2.1 Calculation of PTDFs

The first step of the mid-term flow-based framework is the definition of a set of PTDFs[13]. To obtain these, a European grid model is built, which is for this study based on the TYNDP 2020 reference grid, upon which grid modifications for Belgium are applied at the 2021 target horizon. This grid model is then used to calculate the PTDFs.

A PTDF matrix consists of lines/rows representing the different CNEC's that are taken into account, and columns representing the variables in the flow-based domain.

- Each CNEC refers to the combination of a Critical Network Element and a Contingency.
- The variables can represent the net positions of the market nodes under consideration, the HVDC[14] flows, PST positions, etc; depending on the degrees of freedom that are given to the market coupling algorithm.

Aside from a PTDF matrix, the flow-based mid-term framework also requires the capacity of each Critical Network Element. These correspond to the steady-state seasonal ratings of the network elements.

C.2.2 Flow-based perimeter

The perimeter describes the zone in which flow-based market coupling is in effect. In 2015 the first European flow-based market coupling was established in the CWE region (BE+DE/LU/AT+FR+NL). In 2018 the Germany-Luxembourg-Autria bidding zone split into separate Germany-Luxembourg and Austria bidding zones.

Today, in 2020, the perimeter thus contains 5 bidding zones: BE, DE/LU, FR, NL and AT. A project to launch flow-based capacity calculation on the CORE region (Figure 4) has been launched. The go-live date of a CORE-wide FBMC is expected to happen mid-2021.

An ongoing project is investigating how to incorporate CH grid limitations into the CORE FB capacity calculation between 2022 & 2025. Similarly, ACER has asked TSOs to do an analysis if it makes sense to move the bidding zone borders between Europe and UK from the Channel CCR into the Core CCR. Next, a merger between CORE, HANSA & Italy North may be investigated.

For the 2021-2022 target horizon, a CORE approximation is used called COREMOD. The difference is visualised in the image below. COREMOD takes into account Switzerland and the Italy North Bidding Zone in the flow-based perimeter, while it excludes CORE countries Slovakia, Hungary, Romania and Croatia.

---

[13] A PTDF coefficient for a CNEC & zone represents the change in flow on the CNEC related to the change in net position of the zone

[14] An HVDC link is a controllable device by nature. Power electronics allow to completely control the flow on the link, therefore not making it subject to Kirchhoff laws.

Switzerland and Italy were included in the MOD version because they have a bigger impact on France and by consequence on Belgium. Eastern European countries are omitted in this representation because of their reduced impact on Belgium.

This results hence in taking into account 11 dimensions instead of the 6 dimensions of CWE (including ALEGrO): FR, BE, DE, NL, AT, CZ, PL, SI, CH, IT and ALEGrO.

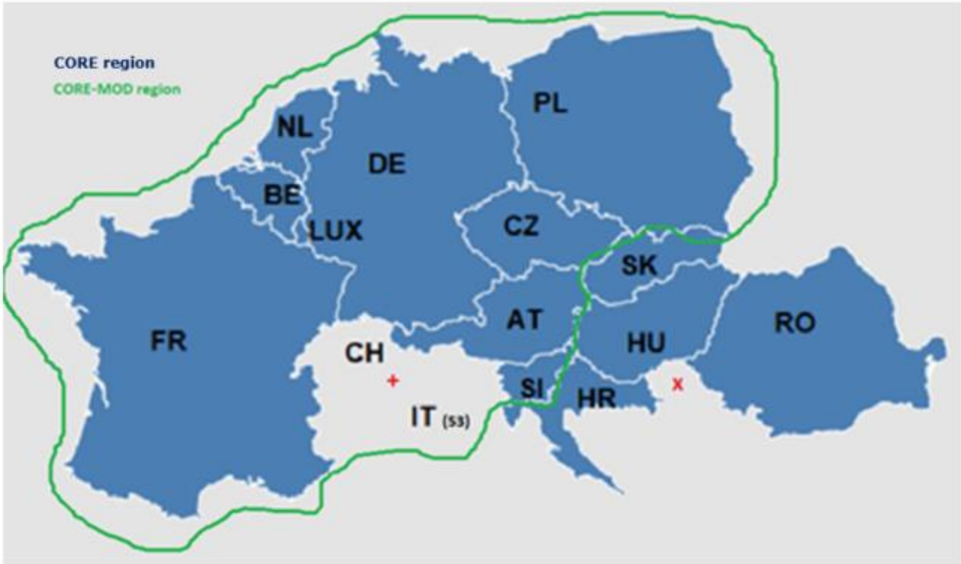


Figure 17

Note that this is a major evolution with regards to the methodology used in the 10-year Adequacy and Flexibility study 2020-30 [1]. Including additional zones significantly increases the complexity of the domain and by consequence the calculation.

C.2.3 Calculating the initial loading of each CNEC

For this study, to be in line with current market operations, only COREMOD is modelled as a flow-based region. The variables are the net positions of the countries[15] (FR, BE, DE (and LU), NL, AT, CZ, PL, SI, CH, IT) toward COREMOD with the addition of ALEGrO as extra dimension. Flows outside of COREMOD are subject to NTC constraints, and the interaction between the flow-based region and flows on external borders to COREMOD are modelled using standard hybrid coupling. ALEGrO is modelled using 'evolved flow-based', introducing a 11th variable in the PTDF matrix.

Once fully set up, the mid-term flow-based framework first performs a market dispatch simulation to determine the initial loading of each CNEC. In this simulation, around 1/2 of the PST tap ranges are allowed to be used to optimize initial flows in order to maximize welfare of the system. The flows from this simulation determine the "Reference Flows". These flows are then scaled back to zero-balance flows per Bidding Zone through the use of GSKs. This procedure mimics the CACM CC process and allows for a good estimation of the pre-loading on CNECs.

C.2.4 Calculating the FB capacity domain

European legislation requires minimum margins to be made available to the market. For this reason, every time a CNEC's margin after preloading is less than the required minimum margin given to the market, the minimum margin is guaranteed.

C.2.5 Clustering of domains

A first market simulation creates an estimation of the dispatch and corresponding initial loadings within CWE for each hour of the simulated year, this would result in 8760 different flow-based domains.

Each flow-based domain is a 11 dimensional shape, one dimension for each of the 11 variables (which can be reduced to 10 using the zero sum constraint). The clustering of the 8760 domains is based on their geometrical shape. For this it is important to define a good distance metric between domains. Next, one needs to define the number of clusters to retain. Pre-clustering data split will be tested (seasonal split, week-end vs week days) to assess potential representative trends. After defining the number of groups, a representative domain per group is chosen. This is done by means of a k-medoid algorithm. Here the medoids are elements which are part of the initial domains, and therefore have physical meaning.

C.2.6 Approximating the domains for computational efficiency

In general, the amount of CNEC's from the real world operational framework domains are too high to be of practical use in market simulations. A flow-based domain is defined by a certain number of inequality constraints depicting the critical branches taking place at a certain time. A flow-based domain is hence a complex polytope. In order to keep the problem size manageable, the flow-based domain can be simplified by approximating it with a regular polyhedron. This is called the Bucky ball approach and allows limiting the number of sides while respecting the characteristics of the flow-based domain.

C.2.7 Stochastic choice of domain depending on climate conditions

The flow-based domains are now ready to be applied to the final market model. The flow-based constraints are transferred onto the model as additional constraints of the global optimisation problem. For each 'Monte Carlo' year, the related climatic year will define the French load & German wind. To perform this matching a correlation between the typical days and specific climatic conditions is examined. For this purpose, a probability matrix is calculated as a function of daily energy ranges (high/medium/low) of wind and load. This calculation provides the correlation of each typical day (24 hourly domains) to given climatic combinations (eg. low wind, high load). For each climatic group, the probabilities of finding a specific cluster are defined as mentioned above, and so a sample of the centroids is drawn adhering to these probability rates.

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 (represented by the day-ahead price reaching the day-ahead price cap) 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 (represented as explained above), 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.

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

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[9] https://www.entsoe.eu/outlooks/maf/Pages/default.aspx

[10] https://www.elia.be/en/infrastructure-and-projects/infrastructure-projects/alegro?clang=en

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