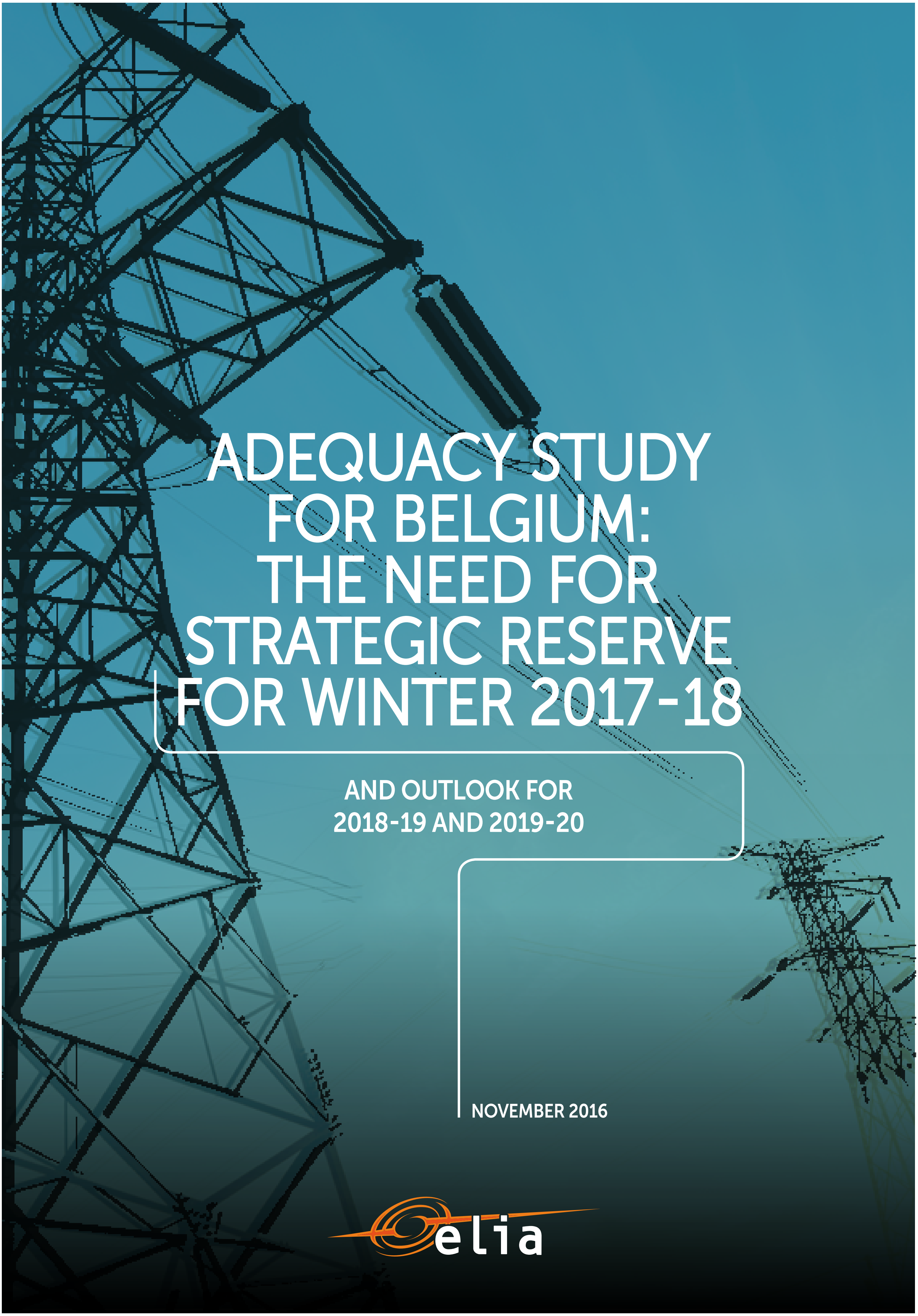


ADEQUACY STUDY FOR BELGIUM: THE NEED FOR STRATEGIC RESERVE FOR WINTER 2017-18

AND OUTLOOK FOR 2018-19 AND 2019-20

NOVEMBER 2016

FOREWORD

Dear reader,

While the winter period 2016-2017 announced itself as a quiet winter in terms of security of supply, recent developments in Belgium and France reminded us that the energy landscape is undergoing continuous change and unexpected evolutions. Even though this report provides an outlook for the future, such recent developments cannot be neglected and therefore I briefly highlight these and some other key features of the report in this preface.

As foreseen by the federal electricity law, Elia provides each year a probabilistic analysis of the situation of the security of supply of the country for the coming winter periods. This analysis is an important element for the federal Minister of Energy when taking the decision if an instruction to Elia is necessary to constitute a volume of strategic reserves. This decision is to be taken no later than 15 January 2017.

Building on the improvements of last year, Elia has further enhanced its transparency and the interaction with stakeholders. In that respect, two public consultations were organised prior to the realisation of this study; the first on the methodology and assumptions and a second on the input data to be used for the calculations. In addition, in agreement with the federal Minister of Energy and its administration, the study is published already in beginning of December, advancing by six weeks the legal foreseen publication date.

The report is elaborated around a 'base-case' scenario which was developed in collaboration with the energy administration and for which the assumptions were set in the middle of October. As some of these assumptions are subject to an almost daily change, Elia has calculated multiple sensitivities in addition to the base-case scenario in order to anticipate the widest range of likely situations as possible for the winter period 2017-18.

However, it is widely known that since mid-October a number of unforeseen and significant developments have taken place on the energy markets. On the one hand there is the increasing uncertainty about the availability of the French and Belgian nuclear generation facilities, on the other hand it became apparent that the French government will not introduce a 'carbon tax'. These events were not covered by the different sensitivities but have a direct impact on the security of supply of Belgium. Therefore, in addition to the 'base-case' scenario and its sensitivities, an alternative scenario was developed, combining these recent developments.

Since it is the responsibility of the Federal Minister of Energy to finally decide upon the most likely scenario and the resulting need of strategic reserves, Elia can only recommend the Minister to consider the latest available information when taking her decision. Elia remains fully at the disposition of the Minister to perform any additional analysis.

I wish you an interesting and pleasant reading experience.

Chris Peeters
CEO Elia

CONTENTS

EXECUTIVE SUMMARY

Under the Electricity Act, Elia is required to submit by November 15 of every year a probabilistic analysis of Belgium's adequacy for the following winter. This analysis is an important element the Federal Minister of Energy must take into account when making the decision regarding the need for a volume of strategic reserve. The deadline for the latter decision concerning winter 2017-18 is 15 January 2017.

This report provides a probabilistic assessment of Belgium's security of supply under several hypotheses and the corresponding need for strategic reserve for winter 2017-18. It also gives a preliminary indication on the need for subsequent winters 2018-19 and 2019-20.

The first scenario, which the study calls the 'base case' scenario, was defined on the situation mid-October 2016 and comprises the following elements:

- a stable total demand forecast with annual growth close to 0%;
- the trend in installed renewable generation capacity as forecast by the regional authorities;
- full availability of Belgium's seven nuclear reactors (5919 MW), except for a historically standard rate of forced outages;
- the trend in thermal generation capacity, based on planned closures announced under the Electricity Act for winter 2017-18 and on market information for subsequent winters;
- a maximum of 4500 MW of import capacity under the grid's normal operating conditions and favourable market conditions;
- the best available estimates for installed generation capacities in neighbouring countries at the time the assumptions were compiled. For France, in particular, this means a standard availability of French nuclear power plants and the closure of some 4 GW of thermal plants expected as a result of uncertain market conditions and the likely introduction of a 'carbon tax'.

Belgium remains dependent on imports for its energy supply. Therefore, any change in assumptions in neighbouring countries has a potential impact on Belgium and on the related strategic reserve volume. In particular, recent developments in France deserve specific attention and have an impact on the need for strategic reserve in Belgium. On the one hand, the French government announced that it will not pursue the introduction of a 'carbon tax'. On the other hand, on average nine nuclear reactors (totalling 8.1 GW) are expected to be unavailable over winter 2016-17 in France. This follows the exceptional extension of some maintenance by the producer, as well as additional shutdowns at the request of the French nuclear safety authority. At this time, the potential consequences beyond the current winter are not known. In addition, in the first few weeks of winter 2016-17, the CWE region experienced a number of situations with limited simultaneous import capabilities for Belgium and France. The root causes of these recent events are currently under investigation in close cooperation with CWE TSOs.

Multiple sensitivity analyses were run to evaluate the impact of potential alternative assumptions and recent developments on generation in France and Belgium. They include:

- the exceptionally low availability of the French nuclear power fleet, as is currently the case for winter 2016-17;
- the recent announcement by the French government that the 'carbon tax' would most likely be abandoned and the implications thereof as anticipated in RTE's forecasts, i.e. 3 GW of extra thermal capacity;
- the long-term unavailability of nuclear reactors in Belgium;
- a higher-than-standard forced outage rate for Belgian power plants.

In total, 15 sensitivity analyses were run for all three winters in order to give an extensive picture of current uncertainties compared to the base case assumptions. In addition, for complete information, an alternative scenario inspired by experience of the first few weeks of winter 2016-17 was run for winter 2017-18; in practice, a combination of some of the above-mentioned sensitivity analyses.

The first scenario, which the study calls the 'base case' scenario, leads to a margin of 800 MW, with an average LOLE of 45 minutes and a LOLE95 equal to one hour.

Under the assumptions of this first scenario, the analysis does not identify a need to contract strategic reserve for winter 2017-18 in order to meet the legal criteria.

From the sensitivity analyses, it can be deduced that:

- In a situation where nine nuclear reactors (in addition to a historically standard unavailability rate) are unavailable in France for the entire winter, partially counterbalanced by a larger available thermal fleet due to abandonment of the 'carbon tax', the margin would be reduced to a much smaller value (100 MW) and would not lead *per se* to a need to contract strategic reserve. This sensitivity reflects the currently expected situation of the French nuclear fleet for winter 2016-17;
- A similar result is observed in case of the unavailability of 1 GW (e.g. nuclear) production in Belgium for the whole winter, which would lead to a margin of 600 MW;
- However, covering a combination of those two events, i.e. the unavailability of 1 GW of (nuclear) capacity in Belgium for the whole winter period, combined with a historically low availability of the French nuclear production (comparable to winter 2016-17), would lead to a need to contract a strategic reserve volume of 900 MW.

These two unavailability hypotheses have a major impact on the results and evolve almost daily. In view of this rapidly changing context, Elia recommends taking a decision based on the latest available information known on 15 January 2017. Concretely, if by that date the above-mentioned units do not receive approval from the competent authorities to restart and/or do not have the perspective on their full availability for winter 2017-18, Elia suggests considering this last scenario and its conclusions, i.e. a need for 900 MW of strategic reserve.

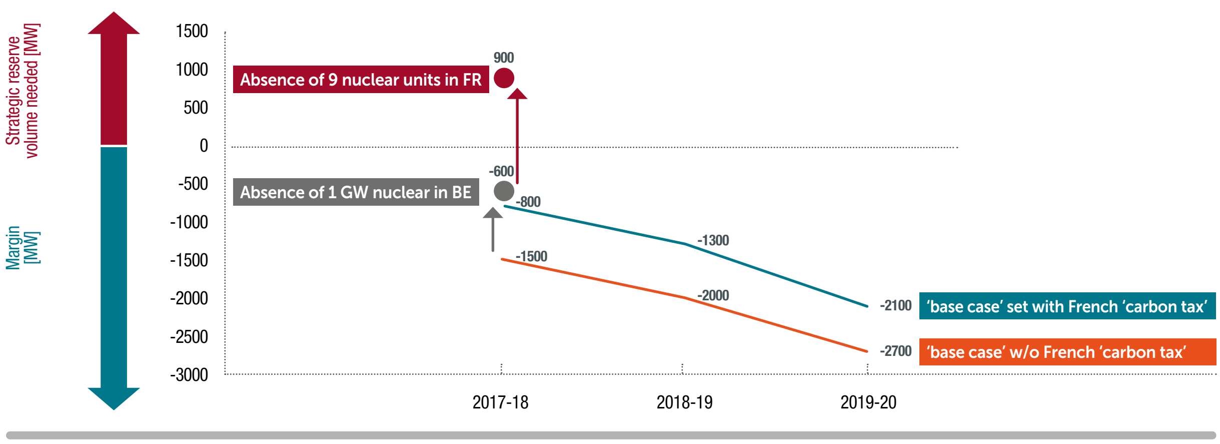
Concerning winters 2018-19 and 2019-20, new developments are expected to increase the margin on the system, in particular: the new biomass 400 MW power plant in Langerlo in 2018-19 and the commissioning of the Nemo Link® interconnector by winter 2019-20. These events show, for the base case scenario, an increased margin of up to 1300 MW for winter 2018-19 and 2100 MW for winter 2019-20. The LOLE average always stays below one hour. The LOLE P95 reaches 0 hours in 2018-19 and 2019-20 as the probability of having a structural shortage hour is less than 5%. Again many assumptions (in particular those analysed in the sensitivity analyses) may impact those indicative results.

Finally, when interpreting the results, the following key assumptions should be taken into account:

- The calculated volume does not distinguish between reductions in demand or production capacity. The volume is calculated on the assumption that this volume is available for 100%;
- The volume is calculated without taking into account the possibility of being able to find this volume effectively in Belgium;
- The margin or deficit (need for strategic reserve volume) is calculated so as to meet both legal criteria (LOLE average and LOLE P95).

Elia wishes to emphasise that the conclusions of this report are inseparable from the assumptions that are mentioned in this report. Elia cannot guarantee that these assumptions will be realised. In most cases, these are developments beyond the direct control and responsibility of the system operator.

RESULTS FOR 'BASE CASE' WITHOUT FRENCH 'CARBON TAX' AND IMPACT OF THE ABSENCE OF 1 GW BELGIAN AND 9 FRENCH NUCLEAR UNITS DURING THE WHOLE WINTER



01

INTRODUCTION

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 the assessment for the winter period 2017-18 that Elia is required to conduct by 15 November 2016.

Elia has already carried out previous assessments for the winters of 2014-15, 2015-16 and 2016-17. These documents are publicly available on the website of the Directorate-General for Energy of the FPS Economy [1].

The current report builds further upon the major elaboration and expansion that has been introduced since last year. As such, the same structure is applied, covering the following six chapters.

Chapter 1 presents the relevant background and context, an overview of the roles and responsibilities of the various parties involved and describes the communications and consultations that have taken place with the stakeholders regarding this report.

Chapter 2 sets out the methodology that is used and the framework for the probabilistic assessment. The application of this is covered by **Chapters 3 and 4**, which take an in-depth look at the assessment's key parameters and assumptions. The focus here is on available generation resources, consumption in Belgium and situation in the neighbouring countries.

Chapter 5 presents the assumptions regarding the interconnections capabilities for Belgium and neighbouring countries.

Chapters 6 sets out the results of the assessment for the winters of 2017-18, 2018-19 and 2019-20. On top of the 'base case' scenario, several sensitivities are extrapolated to capture the risks around various key assumptions, such as the availability of the nuclear generation units, grid elements, outage probabilities or the situation in neighbouring countries. A more in-depth analysis of the 'base case' scenario for winter 2017-18 is revealed and explained in detail.

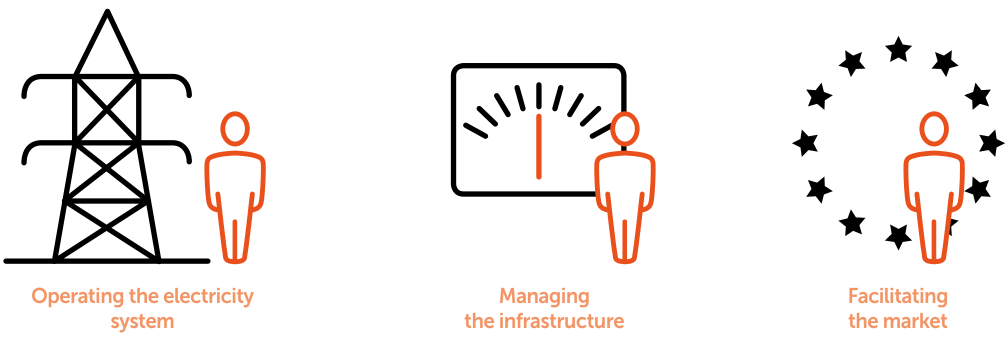
The study ends with **Chapter 7** setting out the conclusions of this report.

THE ANALYSIS FOCUSES ON THE NEXT 3 WINTERS (FIG. 1)

1.1 ROLES AND RESPONSIBILITIES

Elia is Belgium's transmission system operator for the high-voltage grid (30 to 380 kV) and plays a crucial role for society. Through its **three core activities** (see Figure 2), Elia ensures the reliable transmission of electricity both now and for the future.

MAIN ACTIVITIES OF ELIA (FIG. 2)



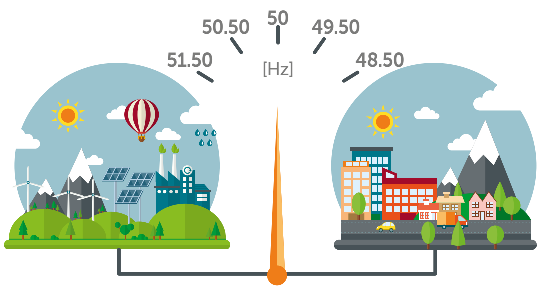
Elia's three core activities are:

1. OPERATING THE ELECTRICITY SYSTEM

This task is facing increasing challenges. Accordingly, sophisticated tools and processes and special competencies are needed to maintain the balance on the system 24 hours a day, all year round. As electrical energy cannot be stored (in high volumes), this balance has to be maintained in real time with a view to ensuring a reliable supply and efficient operational management of the high-voltage grid. The new role of managing the strategic reserve is part of this task.

BALANCE BETWEEN SUPPLY AND DEMAND (FIG. 3)

In an electricity system, the generated energy must always match the consumption. If there are any differences, the grid's frequency will rise (overproduction) or fall (consumption exceeding generation). Elia's role is to maintain this balance at all times.



2. MANAGING THE INFRASTRUCTURE

In the past, power plants were built near cities and industrial areas. However, since the advent of renewable energy sources, the distances between production sites and centres of consumption have increased substantially, one example of this being offshore wind farms. Integrating these sources into the energy mix and ensuring flows from north to south and west to east will require expansion of both the distribution and the transmission grids.

3. FACILITATING THE MARKET

Elia makes its infrastructure available to the market in a transparent, non-discriminatory way, develops new products and services to improve the liquidity of the European electricity market and builds new connections in order to provide the market with new options. Through these efforts, Elia promotes competition between market players and encourages more efficient use of the energy sources available in Europe with a view to boosting the economy and welfare for all.

Besides Elia, many other players contribute to the organisation of the Belgian electricity market. Here is a brief overview of some key players:

- The **generators/suppliers** are committed to meeting their customers' energy needs. They see to it that they have adequate generation or import capacity to fulfil their obligations to their customers;
- The **Balance Responsible Parties** (BRPs[1]) ensure quarter-hourly balance between all their customers' injections and offtakes;
- The **distribution system operators** (DSOs) manage the distribution grids and as such pass on the electricity to the SMEs and private individuals connected to their grid;
- The **federal government** determines general policy, including on the security of the energy supply;
- The **federal regulator** (CREG[2]) has both the duty of advising the public authorities on the organisation and operation of the electricity market and the general task of supervising and monitoring the application of the relevant laws and regulations.

1. BRP: Balance Responsible Party. This is also called an access responsible party (ARP). This may be a generator, a major consumer, an electricity supplier or a trader, among others.
2. CREG: Commission for Electricity and Gas Regulation.

1.2 LEGAL FRAMEWORK AND 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 4 –:

This law 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.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.*

The following texts are taken from the Electricity Act and are not available in English (only in French and Dutch). It was translated from those languages for reading purposes. 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.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.*

PROCESS DEFINED BY ART. 7 OF THE ELECTRICITY LAW (FIG. 4)

Agreement on assumptions with FPS	ELIA gives an advise on the volume based on a probabilistic approach to FPS	FPS submits an advise on the volume to the Minister of Energy	Decision on volume by the Minister of Energy
15 OCT.	15 NOV.	15 DEC.	15 JAN.

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

1.3 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 5). The model Elia uses for the probabilistic assessment enables the calculation of both indicators.

ADEQUACY CRITERION (FIG. 5)

LOLE < 3 hours

LOLE95 < 20 hours

ART.2, 52° - 53°

– *"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[7]"**: 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[8]"**: the probability that at a given time a loss of load situation will occur, expressed in %.

LACK OF HARMONISED STANDARDS FOR SECURITY OF SUPPLY AT EUROPEAN AND REGIONAL LEVELS

In 2014, CEER[9] published a report giving an overview of the adequacy assessments in various European countries [2]. This report reveals the lack of harmonisation in the methodology and in the adequacy criteria used in these countries and are still valid for this analysis.

In seven countries (Great Britain, France, the Netherlands, Finland, Hungary, Belgium and the Republic of Ireland), the indicators are based on a probabilistic adequacy assessment. However, the criteria differ (LOLE of three hours per year in Belgium, France and Great Britain, four hours per year in the Netherlands, and eight hours per year in the Republic of Ireland). By contrast, Sweden and Spain work with a quantitative methodology based on power balance (capacity margin).

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[10]) and generation capacity (SGR[11]):

– 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).
– 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 in included in the contracts.

Further information about the strategic reserve product and the operating modalities can be found on Elia's website [3].

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. ENS: Energy Not Served.
8. LOLP: Loss Of Load Probability.
9. CEER: Council of European Energy Regulators.
10. SDR: Strategic Demand Reserve.
11. SGR: Strategic Generation Reserve.

HOW TO INTERPRET THE ADEQUACY CRITERIA?

The following indicative figure (see Figure 6) shows how to interpret the adequacy criteria. A large amount of future states are calculated for a given winter in a probabilistic assessment (see section 2.1). For each future state, the model calculates the LOLE for the winter. The distribution of the LOLE for each future state can be extracted.

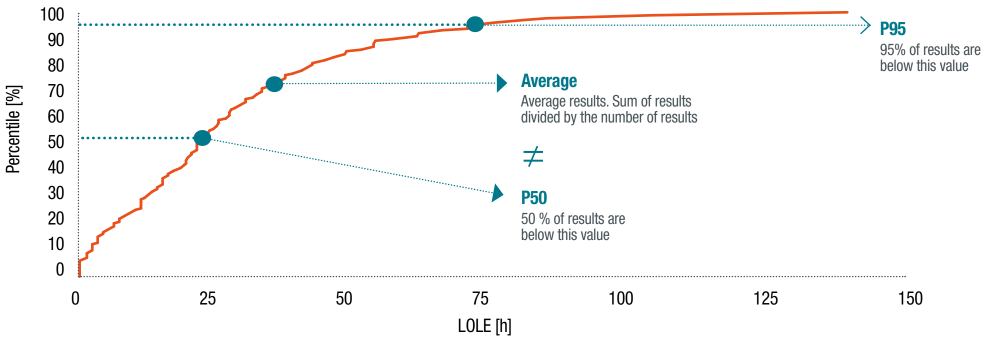
For the first criterion, the average is calculated from all these LOLE results[12]. For the second criterion (95th percentile), all the LOLE results are ranked. The highest value, after that the top 5% of values have been disregarded, gives the 95th percentile (1 chance in 20 of having this amount of LOLE).

Common best practice across Europe is to use the average Loss of Load in a given country in order to assess the adequacy. This is for example the case in France and the Great Britain.

On top of the two criteria from the Electricity Act, the 50th percentile is also shown for all the results. This indicator shows the 1 chance in 2 of having a given amount of LOLE. The figure below also includes this 50th percentile, which is not the same as the average LOLE, except in some rare cases.

Depending on the values of these indicators, 4 situations can be derived from the results as represented in the table below (see Figure 7).

EXAMPLE OF A CUMULATIVE DISTRIBUTION FUNCTION OF LOLE (FIG. 6)



INTERPRETATION OF THE LOLE INDICATOR (FIG. 7)

LOLE average	LOLE P95	LOLE P50	Situation
0	0	0	No LOLE observed in any of the future states
>0	0	0	LOLE in less than 5% of the future states
>0	>0	0	LOLE in more than 5% of future states but less than 50%
>0	>0	>0	LOLE in more than 50% of the future states

12. The average of a series of numbers (LOLE for each status) is calculated by adding up the numbers and then dividing the total by how many numbers there are in the series.

1.4 CURRENT SITUATION AND BACKGROUND CONCERNING THE STRATEGIC RESERVE

Since the introduction of the strategic reserves in winter 2014-15, there has been a strategic reserve volume for each winter period (see Figure 8). More specifically, the strategic reserve contracted for **winter 2014-15** comprised:

- 750 MW of generation capacity, contracted for three years;
- 96.7 MW of load-shedding capacity, contracted for one year.

The strategic reserve for **winter 2015-16** was partly made up of the capacity contracted since 2014 (three-year contracts) and partly of new reserve capacity. On 1 November 2015, the following capacity was comprised in the strategic reserve:

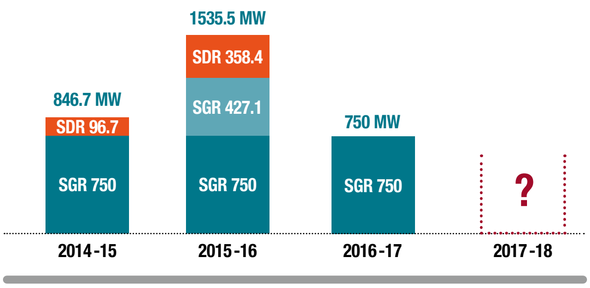
- 750 MW of generation capacity, contracted since 2014;
- 427.1 MW of additional generation capacity, contracted for one year;
- 358.4 MW of load-shedding capacity, contracted for one year.

For **winter 2016-17**, no additional volume was contracted. However, there was still 750MW of generation capacity under contract (three-year contracts as of 2014). Therefore, on 1 November 2016, the following capacity was comprised in the strategic reserve:

- 750 MW of generation capacity, contracted since 2014;

For **winter 2017-18**, no capacity was previously contracted. The decision on contracting capacity for this winter will be taken no later than of 15 January 2017 by the Federal Minister of Energy.

STRATEGIC RESERVE VOLUME CONTRACTED FOR PREVIOUS WINTERS (FIG.8)



1.4.1 HOW IS A RISK TO SECURITY OF SUPPLY IDENTIFIED?

The potential risk to security of supply in Belgium is assessed each day for the seven days ahead. Various items are brought together in a deterministic assessment to work out whether there is an increased risk:

- renewable energy production forecasts;
- the most recent information at Elia's disposal regarding the availability of the conventional generation units;
- an assessment of the potential levels of imports;
- forecasts of Belgium's total electricity consumption.

These assessments are repeated, with the accuracy of the forecasts increasing as the time approaches real-time. As the potential risk is determined on the basis of assumptions and forecasts, it is not absolutely certain that a shortage will actually occur.

1.4.2 WHAT WILL BE COMMUNICATED IF A RISK TO SECURITY OF SUPPLY IS IDENTIFIED?

If the assessments point to a potential risk to the security of supply in Belgium, this will be communicated to the relevant authorities and the general public. Elia's 'Power indicator' on the website and the 'Elia4cast' app were specially developed with a view to communicating information [4] to the general public (see Figure 9).

At the same time, when a structural shortage[13] is identified, this may lead to the activation of the strategic reserve. Notification of any such activation is published on Elia's website [5]. The strategic reserve may be activated by an economic or a technical trigger. Further information about these triggers can be found in the rules governing the functioning of the strategic reserve [6].

The strategic reserve is distinct from the usual balancing mechanisms involving a balancing reserve which tackle immediate and unexpected imbalances and so maintain the balance of the Belgian control area at all times (see section 3.1.5).

Activation of the strategic reserve does not necessarily mean there is or will be a power outage. The strategic reserve is simply an extra means to avoid any interruption in the power supply.

POWER INDICATOR: 7-DAY FORECAST (FIG. 9)

Green
There is enough electricity to cover consumption – no need to worry!

Orange
The amount of electricity generated may not be enough to meet our needs. Let's all make an effort to reduce our consumption mainly at peak times (in principle between 5.00 pm and 8.00 pm) and prevent an outage!

Red
There is not enough electricity to meet our needs at all time. The authorities have decided to take prohibitive measures to cut consumption further.

Black
If not possible otherwise, some consumers will temporarily have their power cut to prevent a widespread, uncontrolled, long-term blackout.

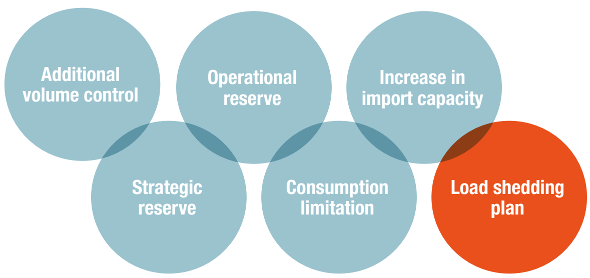
1.4.3 WHAT MEASURES WILL BE TAKEN IF A RISK TO SECURITY OF SUPPLY MATERIALISES?

If a situation arises in which Belgium's supply margins are drastically reduced (maybe even to zero), a number of measures can be taken to tackle the problem (see Figure 10):

- A request to supply potential **extra uncontracted reserve volumes** will be sent to all balance responsible parties. This will allow Elia to call on any remaining capacity at any available power plant or on extra means of controlling electricity consumption. Elia does this by using an RSS1[14] feed to send out a balancing warning on the web [7].
- If appropriate, Elia will use its **contracted balancing reserve volumes**. This involves such wide-ranging measures as activating special quick-start gas units, using contracts with aggregators[15], reducing the consumption of industrial customers and requesting assistance from neighbouring transmission system operators.
- If the situation requires so, Elia will assess whether special measures are possible in coordination and collaboration with the other transmission system operators in the CWE area[16] to further increase Belgium's **import capacity**.
- An economic or technical trigger may give rise to activation of Belgium's **strategic reserve**.
- If the market mechanisms and the reserves are proving insufficient, the authorities may decide to restrict **electricity consumption**. Awareness-raising steps, possibly coupled with prohibitory measures, can be taken first to ensure grid balance for the hours or days ahead.
- The final means of avoiding an uncontrolled general blackout across Belgium is the controlled deployment of the **load-shedding plan**. The decision to roll out this plan is taken the previous evening by the ministers responsible for energy and economic affairs.

These measures will not necessarily be taken consecutively and may possibly be taken by different entities (TSO, Ministry, etc.).

MEASURES IF A SHORTAGE OCCURS (FIG. 10)



13. A structural shortage as defined in the rules governing the functioning of the strategic reserve is a situation in which the total consumption within the Belgian control area cannot be covered by the available generation capacity in this area, excluding balancing reserves and bearing in mind potential imports and energy available on the market [6].
14. RSS: Really Simple Syndication.
15. An aggregator is a demand service provider that combines multiple short-duration consumer loads for sale or auction in organised energy markets.
16. CWE: Central West Europe.

1.4.4 IN WHAT CIRCUMSTANCES WILL THE LOAD-SHEDDING PLAN BE IMPLEMENTED?

The load-shedding plan is a very last resort action that can be used if all the other mechanisms to ensure adequacy are not enough to balance supply and demand. The load-shedding plan is in fact an emergency plan determined for the years ahead, which – like any other plan of this type – applies at any time of the year, whether it is winter or summer. This measure aims to prevent the power grid from completely collapsing, leading to a general blackout in which every consumer in the country would be cut off. This is done by disconnecting specifically targeted areas from the grid for a limited period in order to reduce electricity consumption.

Further practical details of the load-shedding plan (for example, regarding a specific street, length of the intervention and communications at the time of the outage) can be found on the website of the FPS Economy [8].

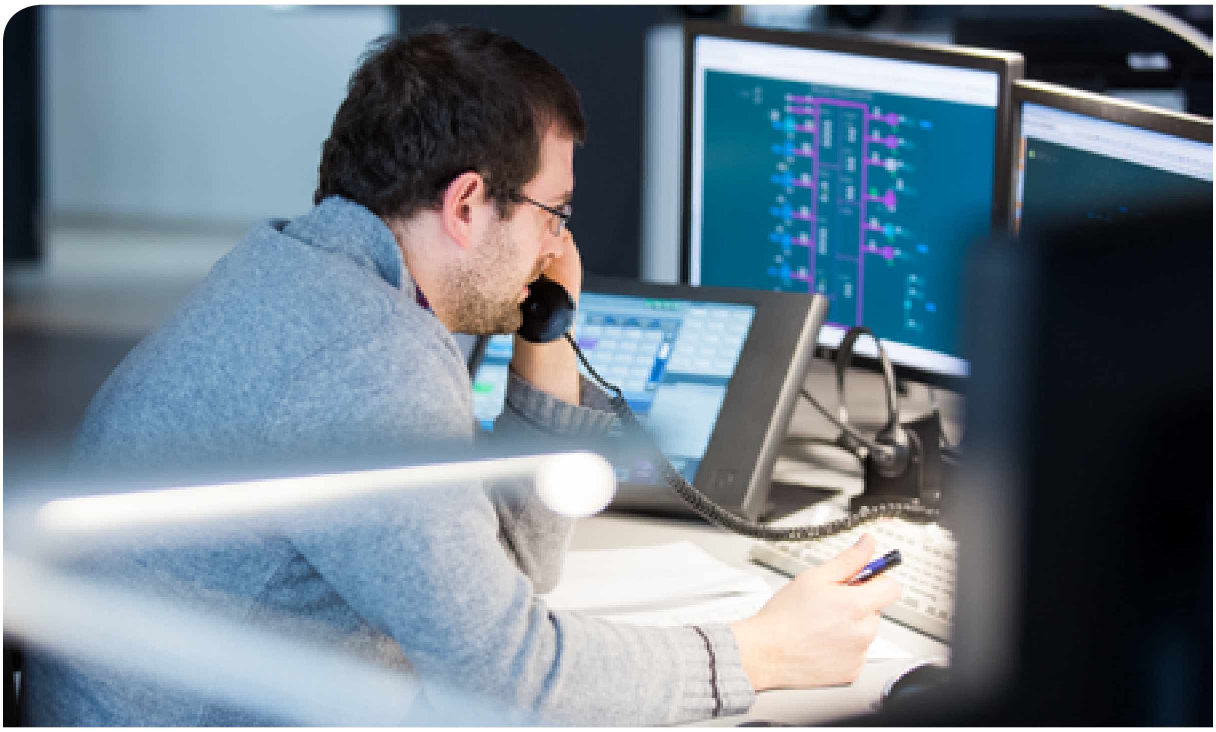
WHAT IS A LOAD-SHEDDING PLAN?

Elia has devised a comprehensive load-shedding plan that can be implemented both automatically, in case of a sudden problem with the frequency on the high-voltage grid, or manually, for example in the event of an anticipated shortage. Such an outage involves disconnecting DSO substations from the grid to maintain system balance and prevent Belgium as a whole from suffering a general blackout (i.e. losing its electricity supply).

In such an outage situation, various high-voltage substations will have to be disconnected. This action affects a number of high-voltage substations, namely those belonging to a single load-shedding group, simultaneously. The load-shedding plan was updated in 2015 and Belgium now has eight such groups (as opposed to six previously), each of which corresponds to 500 to 750 MW. In total, they account for about 40% of total peak consumption. The new load-shedding plan arising from recent adjustments has been operational since 1 November 2015.

The eight groups do not correspond to regional or local geographical areas. Municipalities from various parts of the country can belong to the same group, and a single municipality – or even one street – may be supplied by a number of distribution points that are not even part of the same group. The situation may change further depending on specific factors, such as work on the distribution grid.

The **legal framework** for the load-shedding plan is provided by the Ministerial Decree of 3 June 2005 on the establishment of the load-shedding plan for the electricity transmission network, which forms part of the Defence Plan pursuant to Article 312 of the Royal Decree of 19 December 2002 establishing a grid code for the management of the electricity transmission grid and access thereto.

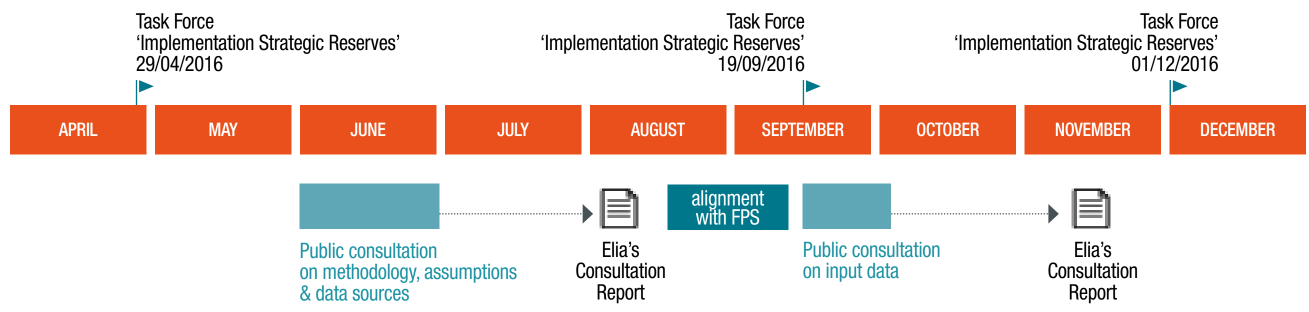


1.5 CONSULTATION REGARDING STRATEGIC RESERVE VOLUME CALCULATIONS

The problems Belgium faces in winter as well as the adequacy and the strategic reserve mechanism are increasingly moving to the fore in energy-related discussions. In the context of the roles and responsibilities that have been assigned to Elia, in particular in relation to the strategic reserve mechanism, Elia is responding to the market players' demand for a better understanding of and more input into the strategic reserve volume calculations.

In this context, Elia launched **two public consultations** in 2016: the first on methodology, assumptions, and data sources, and the second on the raw input to be used for determining the volume. Figure 11 gives an overview of when these consultations took place.

TIME-FRAME OF 2016 (FIG. 11)



The consultations were announced in the meetings of the Task Force 'implementation Strategic Reserves' respectively on 29 April 2016 for the first consultation and on 19 September for the second consultation. They were explained in a presentation [9].

Both consultations were announced on Elia's homepage and each time e-mails were sent out to all the members of the Task Force 'Implementation Strategic Reserve', to the contractual contact points known at the customer relations department and to the regulator, CREG.

1.5.1 FEEDBACK FROM STAKEHOLDERS

Following the two consultations Elia received, respectively, eight and seven (two of which were confidential) responses from stakeholders during the consultation period. These responses can be found on Elia's website [10].

Elia replied to each response. Its replies were aggregated and grouped by subject into two separate consultation documents [10]. The answers were orally explained at the Task Force 'Implementation Strategic Reserve' meeting on 19 September 2016 for the first consultation and 1 December 2016 for the second consultation [10].

FEEDBACK FROM STAKEHOLDERS ON PUBLIC CONSULTATIONS IN 2016 (FIG. 12)

PUBLIC CONSULTATION 1

- **Content**: methodology, assumptions, data sources
- **Consultation Period**: 31 May to 28 June 2016 at 18:00
- **Responses received**: 8
- **Subjects**: market response, flow-based domain, model, data, assumptions, forced outage rates, transparency
- **Consulted document and Consultation Report**: [89]

PUBLIC CONSULTATION 2

- **Content**: raw input data
- **Consultation Period**: 19 September to 3 October 2016 at 18:00
- **Responses received**: 7 (of which 2 were confidential)
- **Subjects**: consultation period, data, sensitivities, market response, flow-based domain, final input data
- **Consulted document and Consultation Report**: [90]

1.5.2 FOLLOW-UP TO THE CONSULTATION

Elia examined the various suggestions and different actions were taken to publish additional data and to perform additional sensitivity analyses on the volume calculations.

It was also decided to take into account more than one flow-based domain in the analysis. Some responses received requested only additional clarifications of the used principles employed, which, consequently will be further clarified in this volume report for winter 2017-18.

Concerning the remarks on market response, it was decided to perform in the short term (during summer 2016) an update on the study conducted in 2015. However in the longer run a different methodology to assess market response will be set up (see also section 3.2.4).

The methodological improvements are explained in more detail in this report. This report has also been expanded to properly address the aspects raised in the consultation. Specifically, this involves providing further information about the assumptions and more background concerning the results.

1.6 METHODOLOGY AND MODELLING IMPROVEMENTS FROM THE PREVIOUS ASSESSMENT

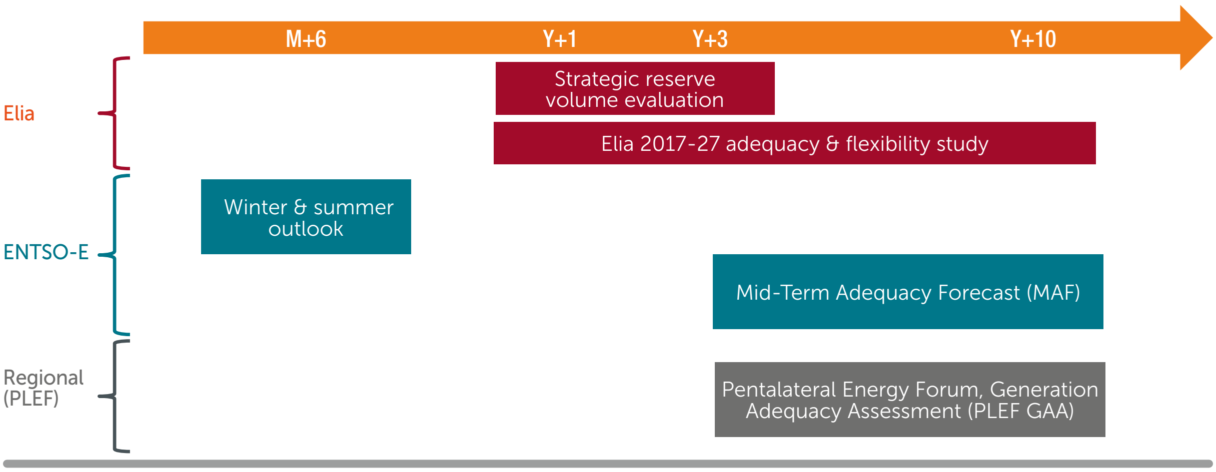
Following public consultations on methodology and new developments in the tools, several improvements in the modelling were implemented for this assessment:

1. The **use of multiple flow-based domains**, making it possible to better model the import capability of Belgium. This is further explained in section 5.1;
2. The use of **random forced outage draws** on the availability of **Belgian pumped-storage units**. The unavailability was previously taken as a derating of the installed capacity of those units. This is further explained in section 3.1.4;
3. **Improved modelling of non-CIPU units** (CHPs, biomass and waste). Modelling via normalised production profiles is complemented with random draws of units' availability. This is further explained in section 3.1.2.2.

1.7 OTHER ADEQUACY STUDIES WITH RESULTS FOR BELGIUM

In addition to this report, there are other, similar reports that deal with the same subject, even though each of them has its own special focus, methodology and time horizon. Figure 13 provides the general overview, after which each bloc/study is detailed further in the text below.

MID AND LONG-TERM ADEQUACY STUDIES WITH RESULTS FOR BELGIUM (FIG. 13)



1.7.1 ELIA'S 2017-2027 ADEQUACY AND FLEXIBILITY STUDY

Elia adequacy and flexibility study 2017-27

LINK:	CLICK HERE [12] [13]
METHOD:	Probabilistic
TIME-FRAME:	2017-2021-2023-2027
PUBLICATION:	04/2016 and 09/2016
SCOPE:	19 countries
COUNTRY RESULTS:	Belgium
FREQUENCY OF PUBLICATION:	ad hoc request by Belgian authorities

Based on Elia's expert knowledge in security of supply analysis, the Belgian Federal Minister of Energy assigned Elia with two specific missions for 2016.

The first mission was to produce a long-term analysis (period 2017-2027), examining the adequacy of electricity generation in relation to consumption and assessing the need for flexibility in the electricity system.

Elia conducted the study, which is essentially a quantitative analysis of Belgium in the context of the European market. While the study scope comprises 19 European countries, the findings focus only on Belgium.

Given the broad scope of such an analysis, the methodology and assumptions were developed in close collaboration with DG Energy and the Federal Minister of Energy. In addition, full transparency was ensured for the report and its findings. Accordingly, special workshops and presentations were held and the full report is available on Elia's website [12].

The second mission was a follow-up to the first one. More specifically, following the publication of the first study, DG Energy organised a public consultation, open to all market actors and institutions in Belgium.

This public consultation led to Elia being requested to analyse an additional scenario ('addendum') with regard to the need for adequacy and flexibility in the Belgian electricity market for the period 2017-2027.

This addendum is based on the same methodology but with some changes to the initial assumptions, as determined by the Federal Minister of Energy. This addendum was also presented to and shared with market parties and is publically available on Elia's website [13].

1.7.2 ENTSO-E: OUTLOOK REPORTS

ENTSO-E Winter and Summer outlooks

LINK:	CLICK HERE [17]
METHOD:	Deterministic
TIME-FRAME:	next winter/summer
PUBLICATION:	every 6 months
SCOPE:	all pan EU perimeter
COUNTRY RESULTS:	all pan EU perimeter
FREQUENCY OF PUBLICATION:	Twice a year

Every year, ENTSO-E publishes a report entitled *Winter Outlook and Summer Review*. One of the focal points of this short-term adequacy report is the main adequacy risks for the winter ahead. The report considers various uncertainties such as climatic conditions, outages of generation units, load prospects and load management and stability issues affecting the electricity grid. The report also summarises the main events from the previous summer. The document aims to establish a platform where transmission system operators can exchange information, create transparency and inform stakeholders of potential risks for the winter ahead.

The report presents for the winter period an overview on a weekly basis of the national and regional power balances between available generation capacity and load forecast. ENTSO-E gathers the information to compile this deterministic assessment using a qualitative and quantitative questionnaire completed by all the individual transmission system operators. The same report is also issued every year for the next summer period ahead.

1.7.3 ENTSO-E: MID-TERM ADEQUACY FORECAST

ENTSO-E Mid Term Adequacy Forecast

LINK:	CLICK HERE [16]
METHOD:	Probabilistic
TIME-FRAME:	2020 - 2025
LATEST PUBLICATION:	07/2016
SCOPE:	all pan EU perimeter
COUNTRY RESULTS:	all pan EU perimeter
FREQUENCY OF PUBLICATION:	Yearly

Each year, until 2015, ENTSO-E[17] published the *Scenario Outlook & Adequacy Forecast* (SO&AF[18]). This report was based on a deterministic method. In 2016, the first Mid-Term Adequacy Forecast (MAF) was published following a probabilistic method such as used at Elia for the assessment of the volume of strategic reserve. The study gives stakeholders in the European energy market an overview of the national and European adequacy situation. The assessment uses bottom-up scenarios and focuses on the LOLE and ENS as adequacy indicators. The report published in 2016 includes an assessment for 2020 and 2025 covering all European countries. MAF study is the first pan-European adequacy assessment using several probabilistic models but the same methodology.

Several improvements in the methodology and data are planned for subsequent editions, such as:

- the inclusion of demand side response;
- the extension of the climate database to more years (from 13 to 34);
- the migration towards a flow-based methodology;
- the assessment of more generation scenarios.

Elia contributed and will contribute towards improving the methodology and modelling for subsequent editions as most of the planned improvements are already included in Elia's adequacy assessment.

1.7.4 PENTALATERAL ENERGY FORUM (PLEF[19]): REGIONAL GENERATION ADEQUACY ASSESSMENT

PLEF Generation Adequacy Assessment

LINK:	CLICK HERE [18]
METHOD:	Probabilistic
TIME-FRAME:	2018-19 - 2023-24
LATEST PUBLICATION:	01/2015
SCOPE:	19 countries
COUNTRY RESULTS:	AT,BE,CH,DE,FR,LU,NL
FREQUENCY OF PUBLICATION:	ad hoc request by PLEF Ministries

The transmission system operators belonging to the PLEF (BE, DE, FR, LU, NL, AT and CH) region published a regional adequacy study in early 2015, based on a methodology enabling such a regional probabilistic adequacy study (same as used at Elia). This study assesses the main adequacy indicators (LOLE and ENS) for both the various countries and the entire region. The study analysed both winter 2015-16 and winter 2020-21 and was published in March 2015.

The next PLEF adequacy assessment is planned for late 2017 and will cover winters 2018-19 and 2023-24.

17. ENTSO-E: European Network of Transmission System Operators for Electricity organisation representing 42 TSOs from 35 European countries.
18. SO&AF: Scenario Outlook and Adequacy Forecast
19. The Pentalateral Energy Forum has been expanded to include the Swiss and Austrian TSOs.

1.8 DISCLAIMER

This report provides a probabilistic assessment of Belgium's security of supply and the need for strategic reserves for winters 2017-18, 2018-19 and 2019-20. The assessment takes into account the following key assumptions:

- Within the calculated volume, no distinction is made between load shedding and generation capacity. The calculated volume is considered to be 100% available;
- The volume calculation disregards the possibility of actually being able to find this volume in the Belgian market.

Elia would like to stress that the conclusions of this report are inextricably linked to the initial assumptions set out in this report. Elia is not liable for these assumptions being realised, as in most cases they relate to developments falling outside the direct control of the grid operator.

02

METHODOLOGY

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 section 2.1).

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[20] in its adequacy studies for France, by other TSOs in the PLEF for regional adequacy studies and in the ENTSO-E Mid-Term Adequacy Forecast (see section 2.2).

The **last step** is to determine the strategic reserve volume considered necessary to **meet the legal adequacy criteria** (see section 2.3). 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.

1 DEFINITION OF FUTURE STATES

2 IDENTIFICATION OF PERIODS OF STRUCTURAL SHORTAGE

3 EVALUATION OF STRATEGIC RESERVE VOLUME OR MARGIN

2.1 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.

2.1.1 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[21] solar generation;
- daily time series for temperature (these can be used to calculate the hourly time series for electricity consumption);
- monthly time series for hydroelectric power generation.

However, **one variable is not correlated with the others**, namely:

- parameters relating to the availability of the thermal generation facilities on the basis of which samples can be taken regarding power plants' unavailability.

20. RTE: Réseau de Transport d'Electricité, the French transmission system operator.
21. PV: photovoltaic.

CORRELATION OF CLIMATIC CONDITIONS

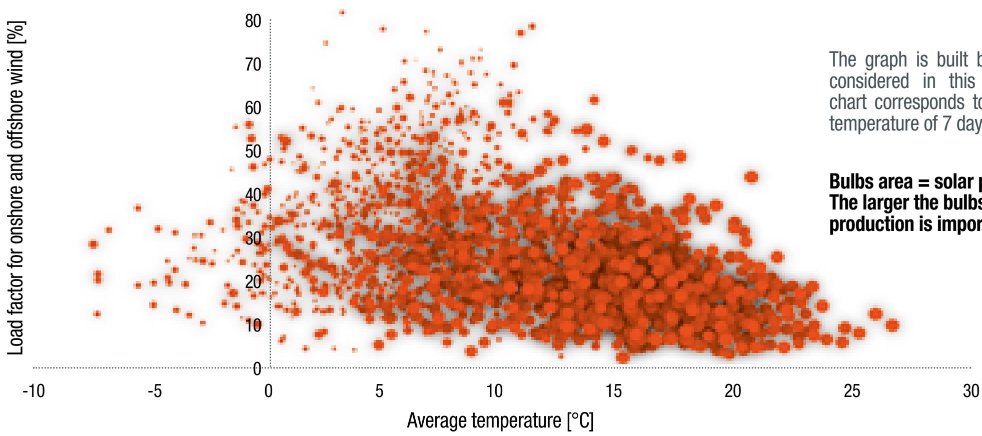
The various meteorological conditions having an impact on renewable generation and electricity consumption are not independent of each other. Wind, solar radiation, temperature and precipitation are correlated for a given region. In general, high-pressure areas are characterised by clear skies and little wind, while low-pressure areas have cloud coverage and more wind or rain. Given the very wide range of meteorological conditions that countries in Europe can experience, it is very hard to find clear trends between meteorological variables for a given country. Figure 14 tries to show the non-explicit correlation between wind production, solar generation and temperature for Belgium. The graph presents the seven-day average for these three variables for Belgium based on 40 climatic years. The hourly or daily trends cannot be seen as the variables were averaged by week but various seasonal and high-level trends can be observed:

- The higher the temperature, the lower the level of wind energy production. During the winter there is more wind than in the summer;
- The higher the temperature, the higher the level of PV solar generation. This is a logical result from the fact that more solar generation goes on during the summer and inter-season months (see Figure 18);
- When the level of wind energy production is very high, the level of PV solar generation tends to fall;
- In extremely cold periods, wind energy production falls while there is a slight increase in PV solar energy generation. This is a key finding that will affect adequacy during very cold weather.

The various meteorological data are also geographically correlated as countries are close enough to each other to be affected by the same meteorological effects. A typical example of this is a disturbance first spreading over western France, then over Belgium and after that over Germany. It is essential to maintain this geographical correlation between countries in terms of climate variables.

Given the high amount of renewable energy from intermittent sources that is installed each year in Europe and the high sensitivity to temperature of some countries' electricity demand, maintaining the various geographically and time-correlated weather conditions is essential.

CORRELATION BETWEEN WIND PRODUCTION, SOLAR PRODUCTION AND TEMPERATURE (AVERAGE OF 7 DAYS) (FIG. 14)



The graph is built based on the climatic years considered in this study. Each bulb on the chart corresponds to the average production or temperature of 7 days for Belgium.

Bulbs area = solar production. The larger the bulbs, the more solar production is important.

The climatic variables are modelled on the basis of 40 historical winters, namely those between 1975 and 2015. The historical temperature and precipitation[22] data come from the NCDC[23] database in the United States [19]:

- The hydroelectric power generation data come from ENTSO-E and cover the years from 1991 to 2015. The data for the other years, so from 1975 to 1990, are reconstructed on the basis of the historical precipitation data for each country (NCDC);
- An evaluation of the various meteorological stations in each country is used to calculate the average temperature there (NCDC).

The hourly wind energy production and solar generation data are used as the historical data for ENTSO-E studies. These data cover the years from 2000 to 2015. A statistical method is used to reconstruct data for 1975 to 1999. This method considers the correlation with other climatic conditions.

The availability data for Belgian thermal generation facilities come from a historical analysis based on the years from 2006 to 2015 (see section 3.1.3.2). For the other countries, the unavailability data from the ENTSO-E studies or from bilateral contacts are used.

The climatic conditions are modelled using 40 (historical) climatic winters.

VARIABLES (FIG. 15)

Sunshine hours, temperature	▶	Hourly solar production
Hourly wind speed	▶	Hourly wind production
Monthly hydraulic production	▶	Hourly production decided by the model by minimising the cost of the system
Daily temperature	▶	Hourly consumption taking into account the thermosensitivity
Probability and duration of failure	▶	Random selection of the daily availability by the model

22. Data from a number of meteorological stations in each country
23. NCDC: National Climatic Data Centre

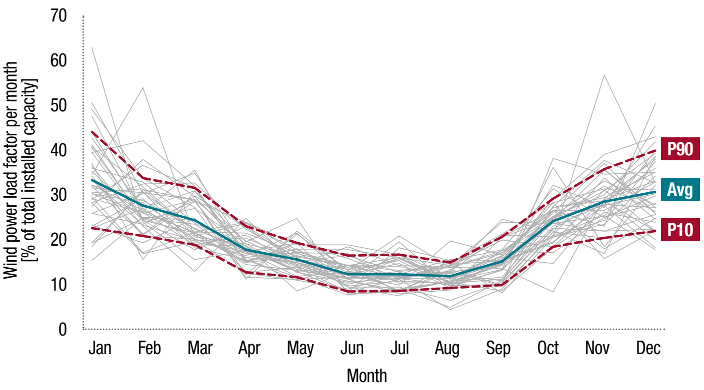
VARIABILITY OF WIND ENERGY PRODUCTION

Wind energy production depends on the wind speed where the wind turbines are located. Figure 16 shows the wind power load factor each month[24] for the 40 historical years used in the assessment. Here the average value, the 10th percentile (P10) and the 90th percentile (P90) are marked for each month in the graph. The graph shows that the level of wind energy production is higher in the winter than in the summer.

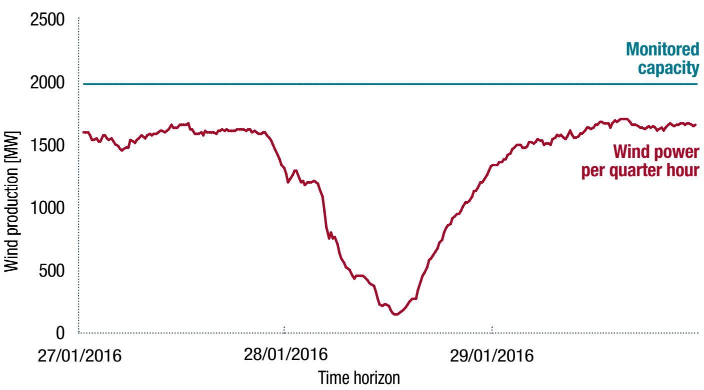
As well as the variability depending on the month, wind energy production may fluctuate considerably across the same day, as illustrated in Figure 17.

The greater the installed capacity of the wind farm, the more wind energy contributes to helping ensure system adequacy. If there is little or no wind, other generation units will have to be activated to meet the electricity demand. In other words, a lack of wind hampers security of supply.

VARIABILITY OF ONSHORE WIND POWER PER MONTH IN BELGIUM ON THE BASIS OF 40 HISTORIC YEARS (FIG. 16)



HISTORIC EXAMPLE OF THE WIND GENERATION VARIABILITY PER DAY (FIG. 17)



VARIABILITY OF PV SOLAR GENERATION

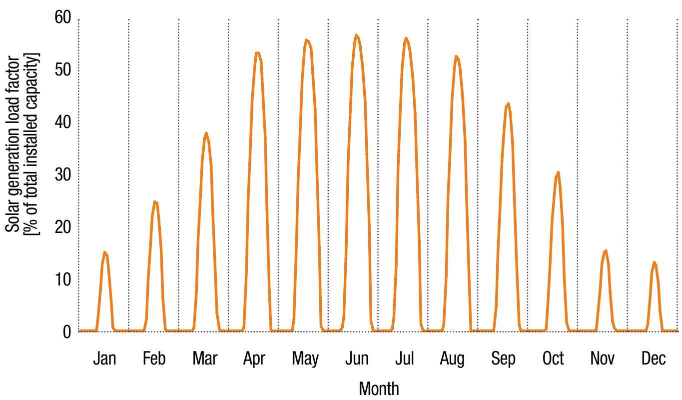
PV solar generation is subject to the variability of the sunshine. The average level of generation is higher in the summer than in the winter:

- the hours of solar radiation rises in the summer (reaching a peak at summer solstice around 21 June and a low at winter solstice around 21 December);
- the incident solar radiation is greater at summer solstice than at winter solstice (as the sun is higher in the sky);
- the weather (for example cloud cover) has a major impact on solar generation;
- the performance depends on, among other things, the outside temperature, meaning that the performance level is higher in cold weather.

Figure 18 shows the solar generation load factor for an average day in each month of the year in Belgium.

As PV solar generation levels are low during the winter, solar generation's contribution to security of supply is fairly limited. Furthermore, the level of generation is zero during the winter peaks because by then the sun has already gone down.

AVERAGE HOURLY LOAD FACTOR PER MONTH FOR BELGIUM (FIG. 18)



24. The load factor is the ratio between the electrical energy actually generated during a given period and the energy which would have been generated if the facility had been operating at nominal capacity during the same period.

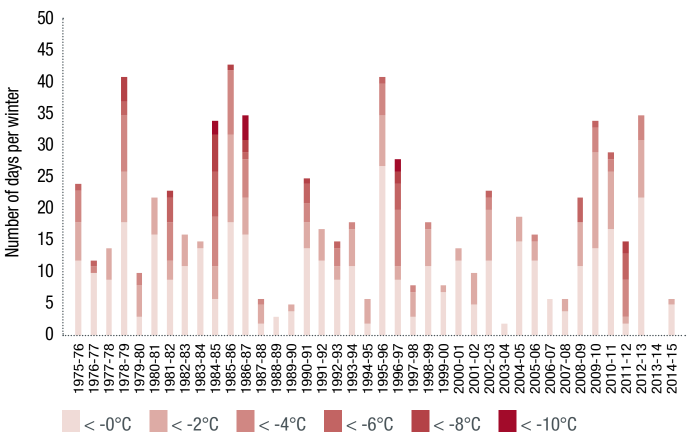
VARIABILITY OF TEMPERATURE

The temperature is decisive in determining the risk of a structural shortage due to the sensitivity of the demand for electricity to temperature. The colder the weather, the higher is the level of electricity consumption (see section 3.2.3) for Belgium.

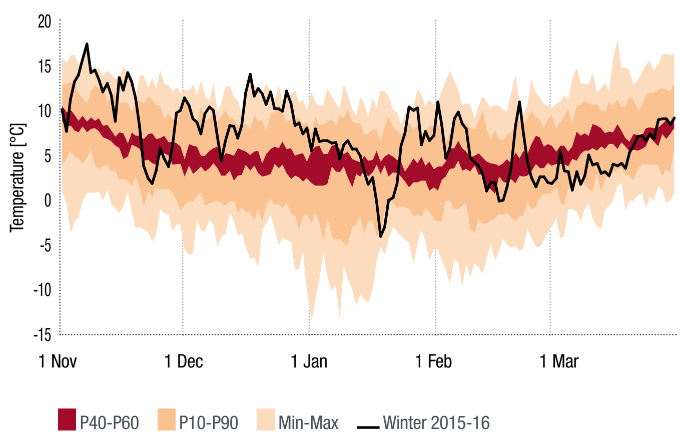
Figure 19 shows for every winter since 1973 the number of days when the average day temperature was below 0 °C (as measured at the Royal Meteorological Institute in Uccle). The colour code indicates how far below zero this was (the darker the colour, the lower the temperature).

Figure 20 gives the distribution of the equivalent daily temperature observed in the period from 1975 to 2015, indicating for each day the P10-P90 range, P40-P60 range and minimum and maximum range. The temperature observed in winter 2015-16 is also shown. Statistically, the coldest periods in Belgium are in December and January although cold waves can also take place in other months.

WINTER SEVERITY (BASED ON THE AVERAGE DAILY TEMPERATURE IN UCCLE) (FIG. 19)



DISTRIBUTION OF THE DAILY TEMPERATURE IN BELGIUM BASED ON 40 HISTORICAL WINTERS (FIG. 20)



WHAT IS A COLD SPELL?

A cold spell is a weather phenomenon defined by the rate at which the temperature falls and the associated minimum value to which it falls. These criteria are defined depending on the geographical region and time of year. For Belgium, a cold spell is described as a period where the daily temperature is lower than -2 °C for at least 7 consecutive days **and** when at least one of the following conditions is met :

– the low temperature during this period dropped at least twice to below -7 °C;

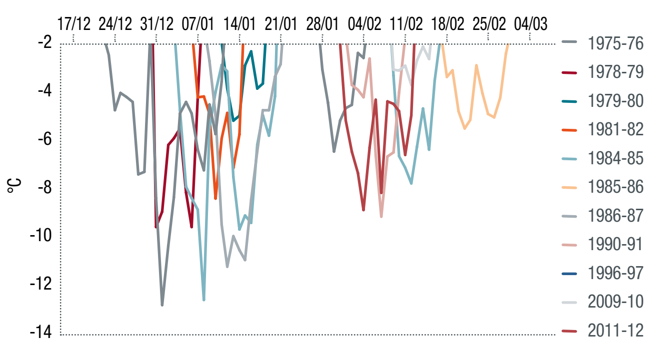
– the high temperature remained below 0 °C for 3 days during the period to.

Physically, the cold wave is characterised by 3 distinct phases:

1. The **cooling phase or cold advective phase** lasts around 2-3 days;
2. The **self-supply of this cold phase or the radiative phase** having a highly variable duration, from a few days to weeks. Its duration and its associated strength define the intensity of the cold snap;
3. The **heating phase or hot advective phase** with a very fast duration, typically below 24 hours or also few days.

Figure 21 illustrates the different cold spells that have occurred in Belgium since 1975. The last cold snap was recorded in winter 2011-2012 with a temperature around -10 °C for a limited duration.

TEMPERATURE IN A COLD WAVE (7 CONSECUTIVE DAYS AVERAGE T° IN BELGIUM <-2° C) (FIG. 21)



Source and more information can be found on the meteobelgique.be website [15].

VARIABILITY OF HYDROELECTRIC POWER GENERATION

Hydroelectric power generation (excluding pumped-storage power plants) depends on the supply of water in the reservoirs (precipitation, melting of snow or glaciers), the size and management of the reservoirs and the location of the various hydroelectric power plants.

A dry year reduces the generation potential of hydroelectric power plants.

Figure 22 shows that hydroelectric power generation (excluding pumped-storage power plants) in the CWE area (plus Switzerland) has a historical variability level of 4 TWh per month (difference between the 10th and 90th percentiles). The difference between annual generation levels in the driest year (2011) and the year with the most precipitation (2001) comes to almost 50 TWh in the area under consideration.

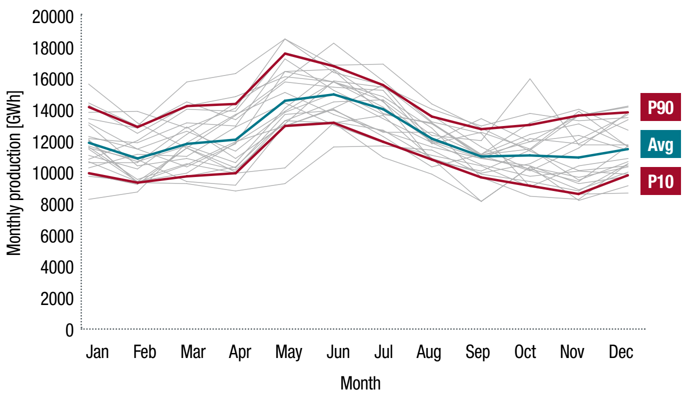
VARIABILITY IN THE AVAILABILITY OF THE THERMAL GENERATION FACILITIES

As regards the availability of thermal generation facilities, random samples are taken by the model on the basis of historical parameters relating to the probability and length of the unavailability.

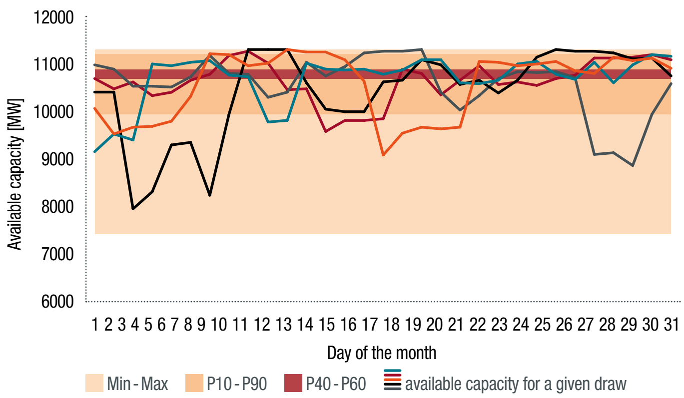
Figure 23 shows the distribution of the various samples for thermal units in Belgium with individual modelling (see section 3.1.3) for a given month. Extreme events (for example, the loss of various power plants) may significantly reduce available capacity. These events may lead to a structural shortage.

The percentiles indicated in the graph correspond to the daily distribution of the availability of power plants based on a large number of random samples for availability. The different lines represent a random draw on the availability of the power plants (total amount of available capacity that can be dispatched for a given day).

HISTORICAL MONTHLY HYDRAULIC PRODUCTION FROM 1991 TO 2015 IN THE CWE AREA + SWITZERLAND (EXCLUDING PUMPED STORAGE) (FIG. 22)



AVAILABILITY OF THE TOTAL CIPU THERMAL GENERATION FACILITIES AFTER DRAW ON FORCED OUTAGES: DISTRIBUTION FOR BELGIUM FOR ONE MONTH (FIG. 23)



OTHER VARIABLES WHICH HAVE A POTENTIAL IMPACT ON SECURITY OF SUPPLY BUT WHICH ARE DISREGARDED IN THIS STUDY

The simulations performed in this study disregard the following events (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 assessed as sensitivities;
- interruption of the fuel supply for the power plants;
- extreme cold freezing water courses used for plant cooling;
- natural disasters (tornadoes, floods, etc.).

Some events listed above (including availability of the nuclear facilities in Belgium or France, long-term loss of a grid component, available generation capacity in France or the Netherlands) **are taken into consideration as sensitivities** (see section 6.2).

2.1.2 'MONTE CARLO' SAMPLING AND COMPOSITION OF CLIMATIC YEARS

The variables discussed in section 2.1.1 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 24).

CONSTRUCTION OF MONTE CARLO YEARS (FIG. 24)

WHAT PERFORMS THE 'MONTE CARLO' METHOD?

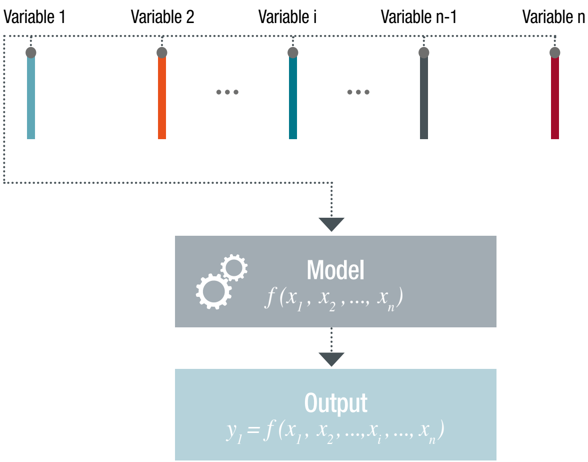
The **'Monte Carlo' method** is used in various domains, among them **probabilistic assessments of risks**. The name of this quantitative technique comes from the casino games in Monaco, where the outcomes for each game were plotted in order to forecast their possible results following a probability 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 25).

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.

The **'Monte Carlo' method** extends the **deterministic method** in that it uses sets of random values as inputs translating the uncertainty associated for these parameters thanks to a distribution function (or a large amount of samples of this distribution). This method is a class of computational algorithms and relies on repeated random sampling. This approach is used when analytical or numerical solutions don't exist or are too difficult to implement and can be described via four steps:

BASIC PRINCIPLE BEHIND THE DETERMINISTIC APPROACH (FIG. 25)



Step 1: Build a model characterised by parameters (inputs with inherent uncertainties) for the studied system

$$y = \int (x_1, x_2, ... x_p)$$

Step 2: Generate a set of values for each input using a distribution function

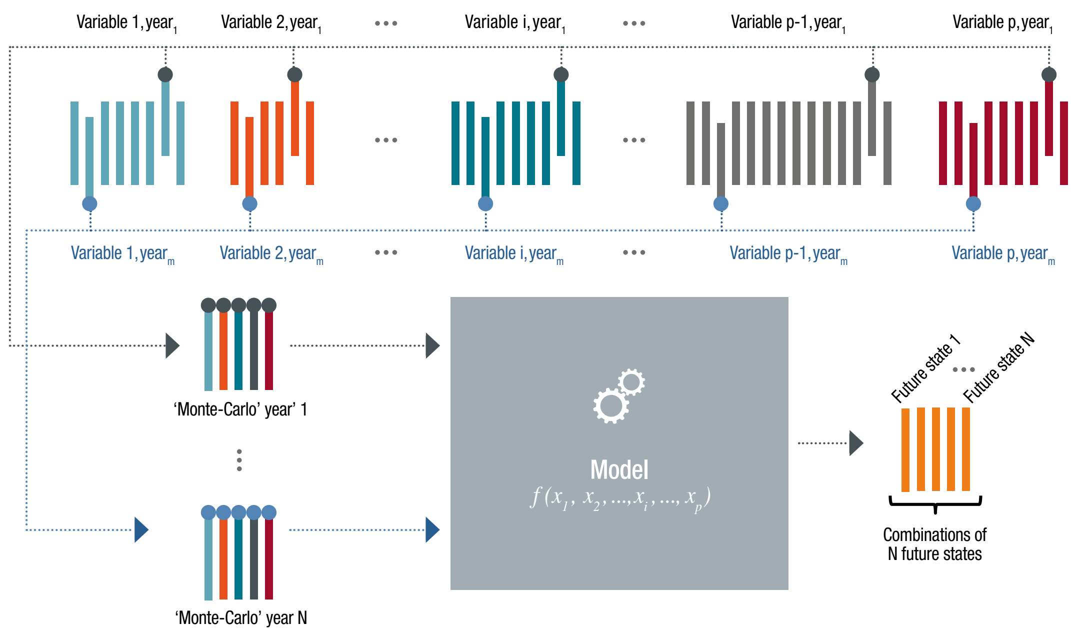
$$Input = \{x_{1,i}, x_{2,i}, ... x_{p,i}\}$$

Step 3: Evaluate the model for a given set of values and store the output y_i

Step 4: Iterate steps 2 and 3 for i = 1 to N, where N represent the number of iterations

The **error** for the results arising from the 'Monte Carlo' method decreases as 1/√N. In this assessment, random samples are taken for the unavailability of the thermal facilities of each country. Future states are determined by combining these samples with the time series for electricity consumption and for specific weather conditions. The simulations are conducted in relation to these future states (also referred to 'Monte Carlo' years, see section 2.2.3). Figure 26 shows a random sample for p independent variables, yielding N different future states.

A LARGE NUMBER OF RANDOM SELECTION ON DIFFERENT VARIABLES ALLOWS TO BUILD THE FUTURE STATES (FIG. 26)



2.1.3 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. This study focuses on the two indicators determined by law, namely the average LOLE and the 95th percentile for the LOLE (LOLE95). These two parameters have to converge enough to ensure reliable results. Depending on the scenario and level of adequacy lower or higher amount of 'Monte Carlo' years can be simulated.

In this study, between 400 and 800 future states are required to achieve convergence of the indicators. This means that all 40 climatic winters will be simulated 10 to 20 times, with the availability of the thermal facilities being different in each of the simulated future states.

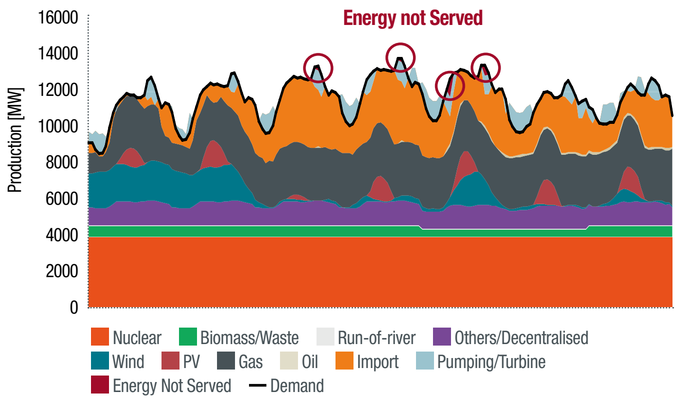
Combining the results of all these future states yields the distribution of the number of hours of structural shortage.

A total of 400 to 800 future states (or 'Monte Carlo' years) are simulated. Each future state corresponds to a historical climatic winter and a random sample for the availability of the power plants.

2.2 IDENTIFICATION OF PERIODS OF 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 27 gives an example of how consumption is covered by the available generation facilities for every hour of the week. If, for a given hour, generation capacity falls 1 MW short of the capacity required to meet demand, this corresponds to one hour of structural shortage. Figure 27 presents the energy that cannot be supplied by the generation facilities.

EXAMPLE FOR GENERATION PER PRODUCTION TYPE FOR A GIVEN WEEK FOR BELGIUM (FIG. 27)



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

In all, the assessment models 20 countries in detail. This makes it possible to determine the available generation abroad when needed in Belgium.

2.2.1 SIMULATION SCOPE COVERING 20 COUNTRIES

As Belgium depends on electricity imports for its security of supply, explicit modelling of its neighbouring countries is compulsory. The **CWE area** covers Germany (DE), France (FR), Belgium (BE), the Netherlands (NL), Luxembourg (LU) and Austria (AT).

In practice, the CWE area and the following countries are modelled: Spain (ES), United Kingdom (GB and NI), the Republic of Ireland (IE), Italy (IT), Switzerland (CH), Slovenia (SI), the Czech Republic (CZ), Slovakia (SK), Hungary (HU), Norway (NO), Denmark (DK), Sweden (SE), Poland (PL) and Portugal (PT). The modelled scope is shown in Figure 28.

Due to the specific market situation in Italy and Denmark, these countries are modelled with six and two market nodes, respectively. This type of specific modelling is in line with the approach used in other studies done within the ENTSO-E context.

SCOPE INCLUDES 20 COUNTRIES: THE CWE ZONE AND ITS NEIGHBOURING COUNTRIES (FIG. 28)

2.2.2 INPUT AND OUTPUT OF THE MODEL

To simulate the European electricity market, a number of assumptions and parameters have to be established. These are detailed in Chapter 3 for Belgium and Chapter 4 for its neighbouring countries.

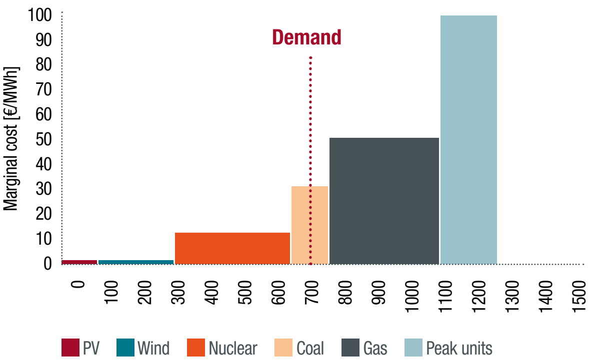
The **key input data** for each country are:
- the hourly consumption profile and associated thermosensitivity;
- the installed capacity of the thermal generation facilities and the availability parameters;
- the installed PV, wind and hydroelectric capacity and associated hourly production profiles 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 29). Using the economic dispatch enables the pumped-storage power plants and hydroelectric reservoirs to be appropriately modelled (see section 3.1.4).

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. The market response to high prices is also taken into consideration, as explained in section 3.2.4.

EXAMPLE OF AN ECONOMIC STACK FOR A GIVEN TIME AND GIVEN GENERATION FACILITIES (FIG. 29)



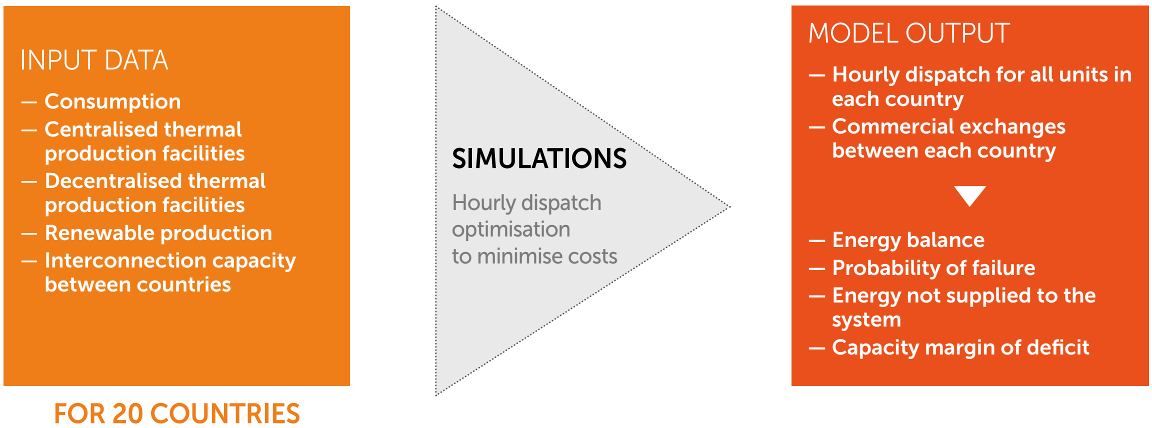
The **output of the model** that is assessed in this study consists of hourly time series showing the energy shortage for each country. These series can be used to deduce various indicators:
- the number of hours of structural shortage;
- the capacity surplus or shortage;
- the number of activations of the strategic reserve;
- Energy Not Served (ENS).

Other output data from the model are used to interpret the results:
- the level of generation for each type of power plant in each country;
- the commercial exchanges between countries;
- the availability of the power plants.

A host of other indicators can also be calculated, such as:
- the countries' energy balance (exports/imports);
- the use of the commercial exchanges;
- the number of operating hours and revenues of the power plants;
- CO_2 emissions;
- the hourly marginal price for each country.

Figure 30 presents a schematic overview of the model's input and output.

INPUT AND OUTPUT DATA FOR THE MODEL (FIG. 30)



2.2.3 MODEL USED TO SIMULATE THE ELECTRICITY MARKET

The market simulator used in the scope of this study is ANTARES[25], 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:

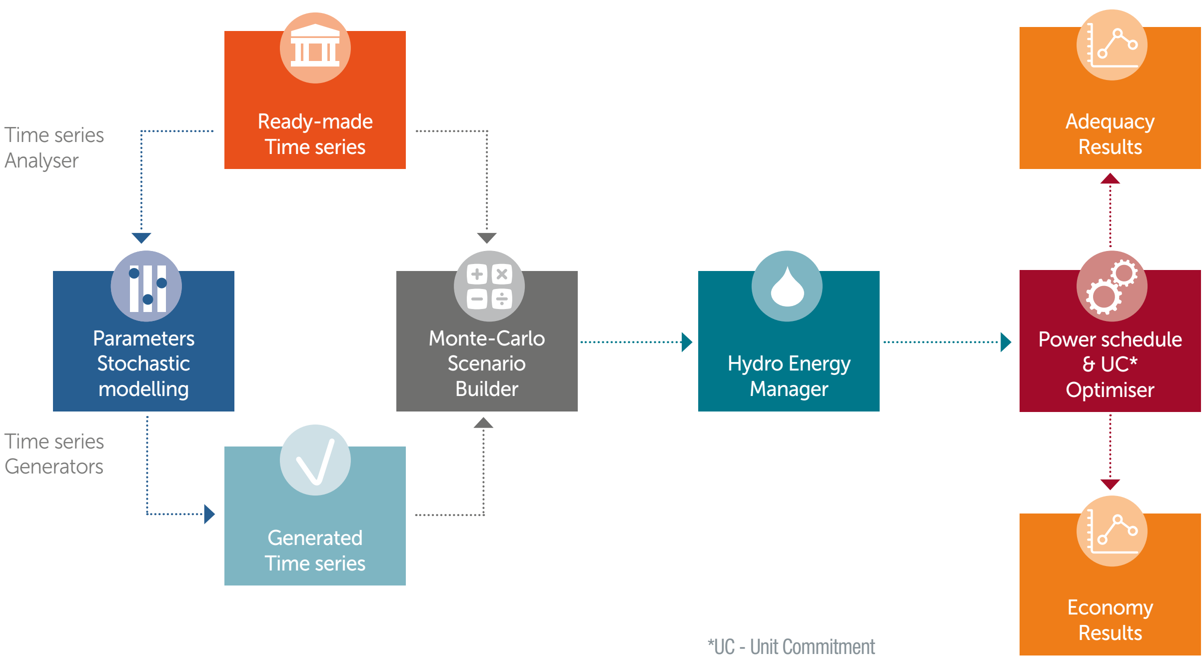
- representation of several interconnected power systems through simplified equivalent models. The European electrical network can be modelled with up to a few hundred of region-sized or country-sized nodes, tied together by edges whose characteristics summarise those of the underlying physical components.;
- 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 optimisation 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 2.1). The main process behind ANTARES is summarised in Figure 31 [14].

ANTARES PROCESS (FIG. 31)



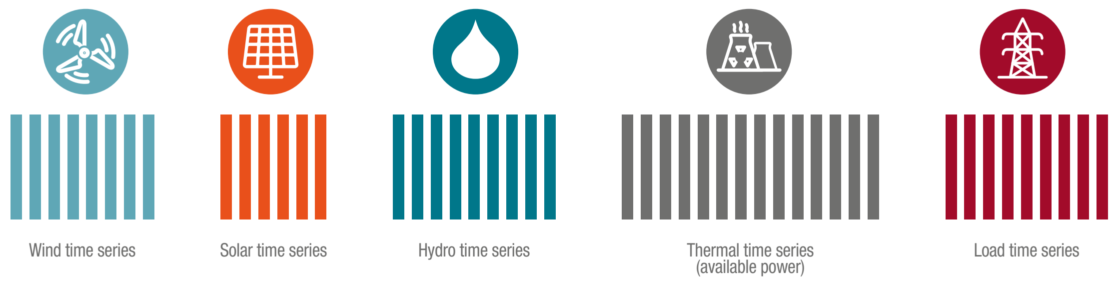
25. ANTARES: A New Tool for Adequacy Reporting of Electric Systems

The simulation scheme behind this process can be described in **4 steps**:

STEP 1: CREATION OF ANNUAL TIME SERIES FOR EACH PARAMETER

For each parameter, **generation** or **retrieval** of **annual time series**, with an **hourly resolution** is needed (see Figure 32). The number of time series for each parameter is usually between 10 to 100 and can be increased if necessary.

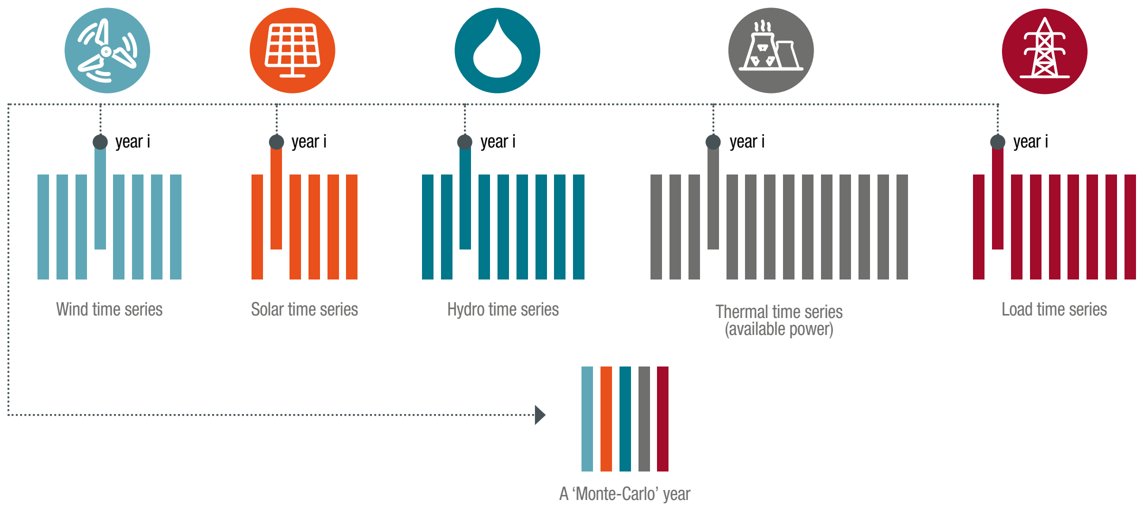
GENERATION OF ANNUAL TIME SERIES FOR EACH PARAMETER (FIG. 32)



STEP 2: CREATION OF A 'MONTE CARLO' FUTURE STATE (YEAR)

For each parameter, a **random selection** of the associated series is performed. This selection can also be made according to **user-defined** rules (**probabilistic/deterministic** mixes). The data selection process for each parameter provides an annual scenario called a 'Monte Carlo' year as shown in Figure 33.

GENERATION OF A 'MONTE-CARLO' YEAR (FIG. 33)



This process is repeated several times (several hundred times) in order to obtain a set of 'Monte Carlo' years representing a set of possible futures.

As described in section 2.1.2., the spatial correlations and the **correlation** between the various **renewable energy sources** (wind, solar, hydroelectric) and the **temperature** are modelled. In other words, this means a selection of wind, solar, hydroelectric production and thermo-sensitive consumption is performed for a **given year**, coming from one of the 40 historical weather scenarios [14].

STEP 3: HYDRO STORAGE ENERGY MANAGEMENT

The aim of this step is to assess and provide to the optimiser weekly hydraulic energy volumes to generate from the different reservoirs of the system, for each week of the current 'Monte Carlo' year. To perform this pre-allocation, the module breaks down annual and/or monthly hydro storage energy into weekly amounts, through a heuristic based on:

Net demand pattern (Load minus RES and must-run generation) calculated from scenario data;

Hydro management policy parameters: to define how net demand is weighted for energy dispatching from year to months and from month to weeks;

Reservoir rule curves: to define minimal and maximal curves in order to constrain the dispatching of hydro energy and to define the maximal power variation with the variation of the reservoir level.

STEP 4: POWER SCHEDULE AND UNIT COMMITMENT OPTIMISER

Two optimisation issues can be addressed in this process: 'adequacy' or 'economy' mode.

The **'adequacy' mode** analyses if there is enough **available generation power**, following the given state of the system, to meet the **demand**, whatever the prices or costs involved. In other words, **no market modelling** is needed since the function that has to be minimised is the amount of load that has to be shed in the whole interconnected system. The '**economy' mode** requires **a market modelling** in order to determine which plants are delivering power at a given time. This process is done through the **economic dispatch** method where the aim is to minimise the operating cost of the overall system by considering classically a 'perfect market' competition (market bids are based on short-term marginal costs) [14].

ANTARES 'economy' mode aims to find the optimal economic dispatch of each hydro and thermal unit, in other words, the one that minimises the total system costs taking into account generation constraints and possible energy exchanges.

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

- the PLEF adequacy study [18];
- the TwenTies project [21];
- e-Highway2050 [22];
- ENTSO-E's TYNDP[26] [23];
- RTE French Generation Adequacy Report [20].

26. TYNDP: Ten Year Network Development Plan

UNIT COMMITMENT 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 optimisation problem whose objective function is the minimisation of the total operational costs of the system. The optimisation 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 optimisation 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 [14].

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 have for instance been 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 comes first in the merit order. More precisely, as other non-dispatchable generation, they are subtracted from 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, beside the time series of available capacity, some parameters necessary for the unit commitment and dispatch calculation are 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 defer 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 (see step 3 in section 2.2.3). 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

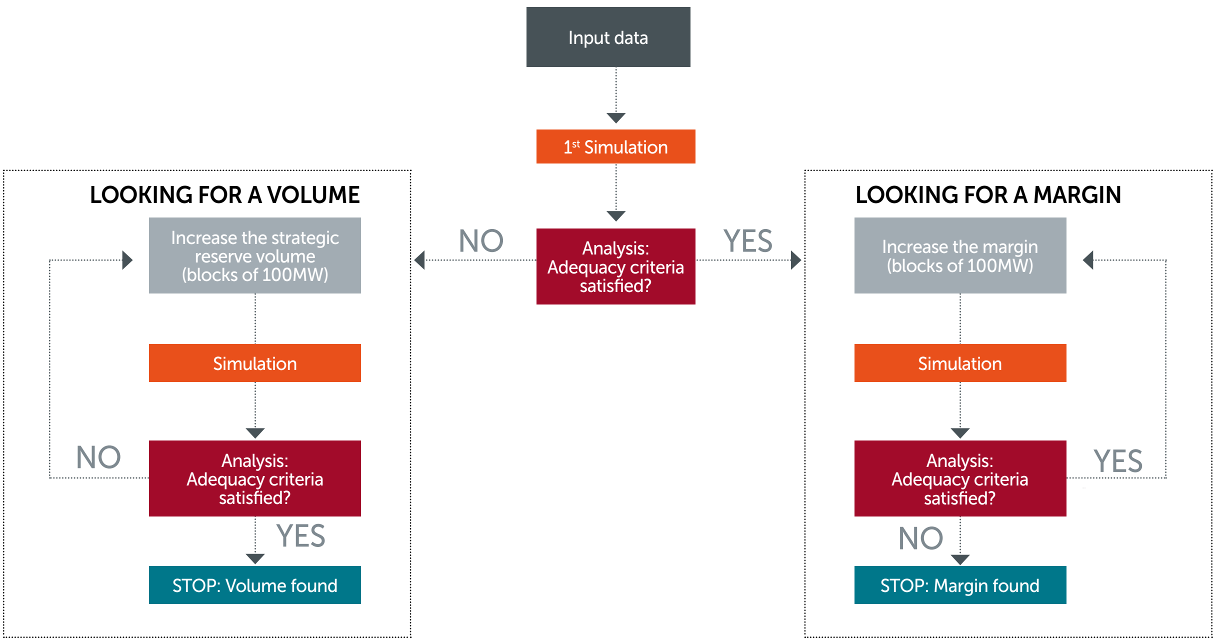
One way of modelling **demand response** in the tool is by using very expensive generation units. Those will only be activated when prices are very high (and therefore after all the available generation capacity is dispatched). This allows replicating the impact of market response as considered in this study. Activations per day and week can be set on this capacity.

2.3 EVALUATION OF THE STRATEGIC RESERVE VOLUME OR MARGIN

If the legal criteria are not met following evaluation of the 400 or 800 'Monte Carlo' years, extra volume 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 sought.

An iterative process is used to evaluate the total strategic reserve volume or margin (see Figure 34). The extra volume or margin is 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.

ITERATIVE PROCESS TO CALCULATE THE VOLUME OF STRATEGIC RESERVE OR THE MARGIN (FIG. 34)



03

ELECTRICITY SUPPLY AND CONSUMPTION IN BELGIUM

This section elaborates on the assumptions and modelling techniques used in this analysis for Belgium. As was mentioned in section 1.5, Elia organised a public consultation on the raw data for Belgium.

In **section 3.1**, the hypotheses used with regard to **Belgian electricity supply** are detailed. Also, the specific modelling of the electricity supply for Belgium is discussed.

Next, **section 3.2** elaborates is given on **Belgian electricity demand**, and the way its specifics are incorporated in the model.

Section 3.3 summarises the input data for Belgium.

ELIA CONTRIBUTES TO MORE TRANSPARENT INFORMATION ON THE BELGIAN ELECTRICITY SYSTEM

Elia provides a large amount of data in real time on its website [25] to allow stakeholders to gain insights into the status of the Belgian transmission system. The data made publicly available on Elia's website include among others:

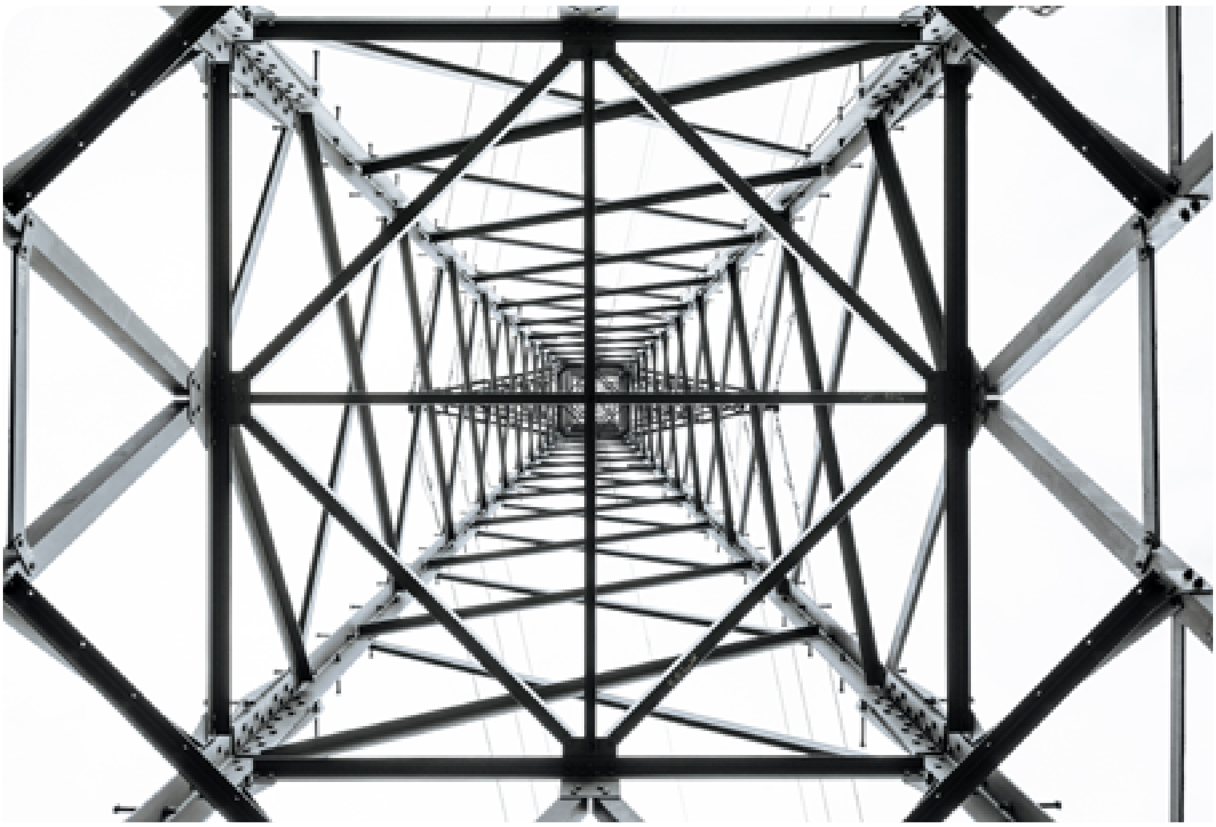
– total Belgian load and Elia grid load;

– photovoltaic and wind production data and forecasts;

– production capacity forecasts.

These and many more data can be downloaded for detailed analysis. Furthermore, Elia contributes to the ENTSO-E transparency platform [40] by providing real-time data.

Elia organised a public consultation on the detailed assumptions used for Belgium in this analysis. See section 1.5 for more information.



3.1 ELECTRICITY SUPPLY IN BELGIUM

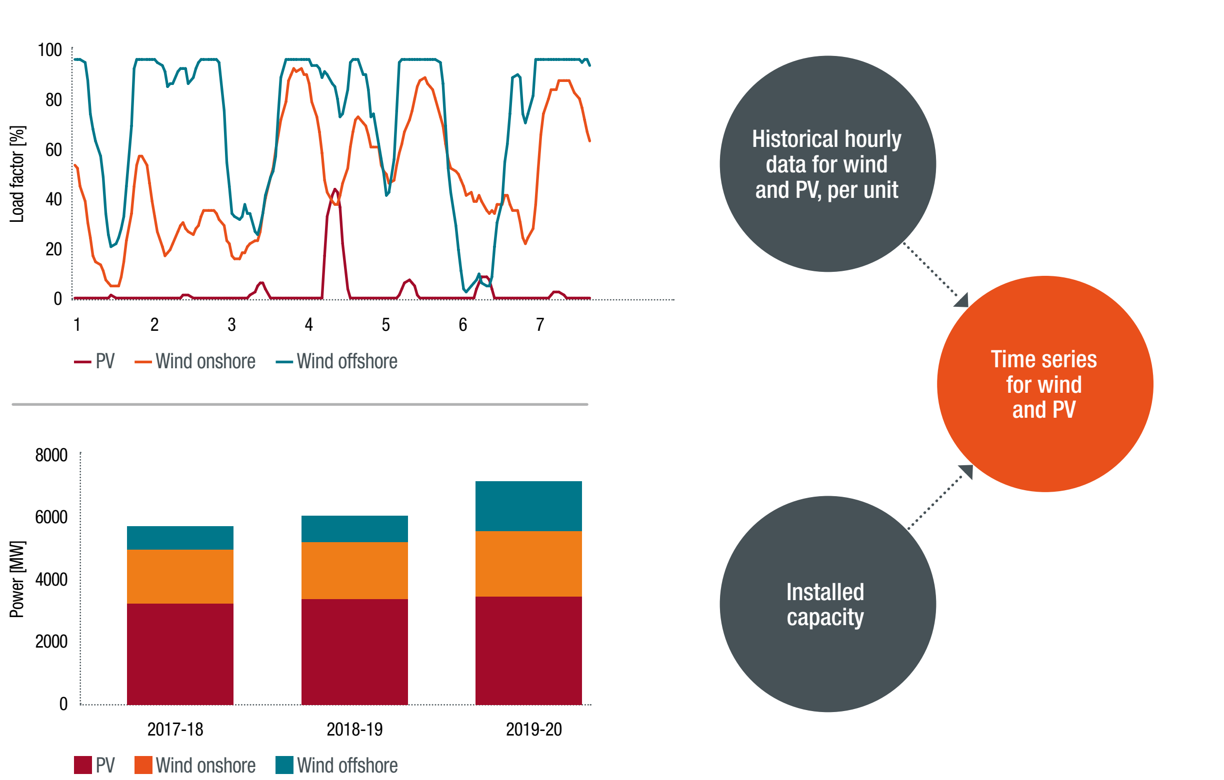
The ANTARES model takes into account the thermal generation facilities, the renewable energy sources, and other electricity production for each country in the simulation perimeter. In line with Article 7bis of the Electricity Law, Elia has received input from the Directorate-General of Energy of the Federal Public Service (FPS) Economy prior to 15 October 2016. The information received from the FPS Economy has been integrated in the report and taken into account in the analysis.

3.1.1 WIND AND SOLAR FORECASTS

The FPS Economy consulted the three Belgian regions, to obtain forecasts for the installed capacity of onshore wind and photovoltaic production. Further details for these forecasts can be found in sections 3.1.1.1 and 3.1.1.3. Elia bases itself on the latest information available to consolidate a forecast of the installed capacity of offshore wind. This is further elaborated on in section 3.1.1.2.

As described in section 2.1.1, historical data is used when modelling wind and photovoltaic production. The forecasts for installed capacity are combined with this historical data to obtain 40 different time series for onshore wind, offshore wind and photovoltaic production. This process is illustrated in Figure 35.

40 TIME SERIES FOR WIND AND PV (FIG. 35)



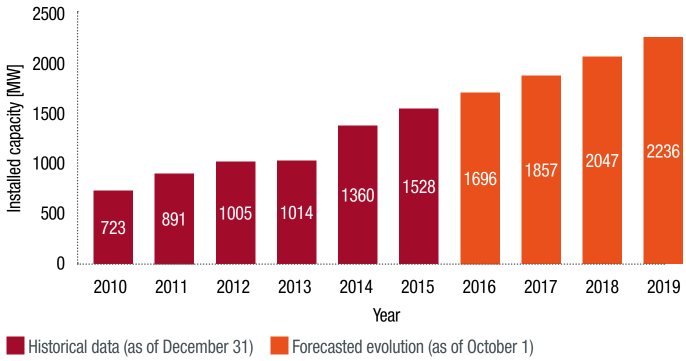
3.1.1.1 WIND ONSHORE

Figure 36 shows the historical trend of installed capacity of onshore wind generation as well as the forecast consolidated by the FPS Economy. On average, the forecast evolution amounts to a yearly increase of 175 MW. By way of illustration, the geographical distribution of the onshore wind farms in Belgium for the period 2016-17 is shown in Figure 37.

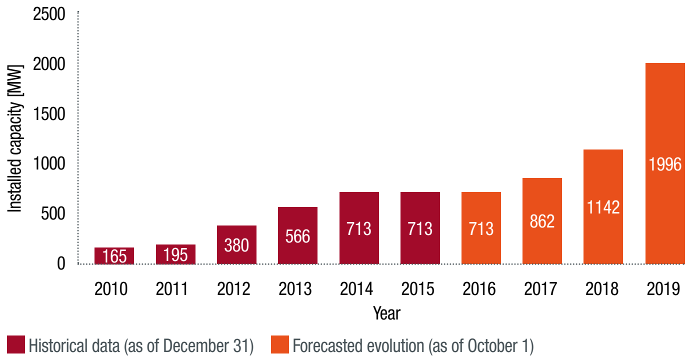
3.1.1.2 WIND OFFSHORE

The Belgian government has awarded domain concessions for the construction and operation of offshore wind power production to nine wind farms (see Figure 39). At the end of 2016, three of these wind farms will be in full operation, totalling 713 MW. Figure 38 shows the historical development of offshore wind installed capacity, as well as the forecast installed capacity that was taken into account in this analysis. This forecast trend is a best estimate, based on the latest information available to Elia.

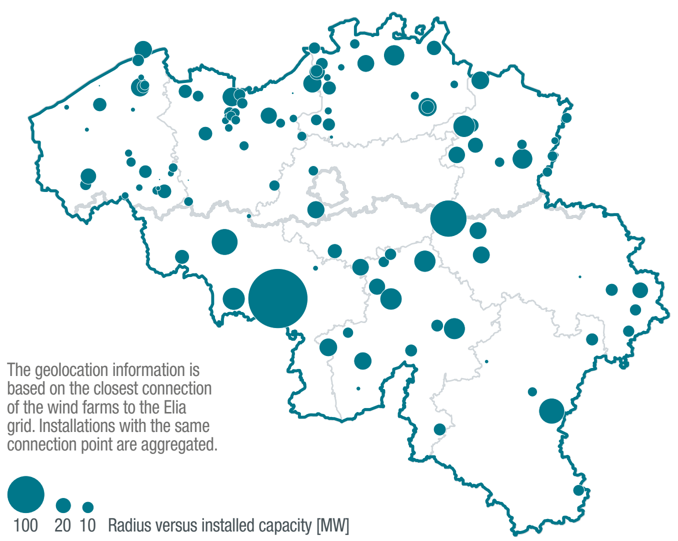
EVOLUTION AND FORECAST OF INSTALLED CAPACITY ONSHORE WIND (FIG. 36)



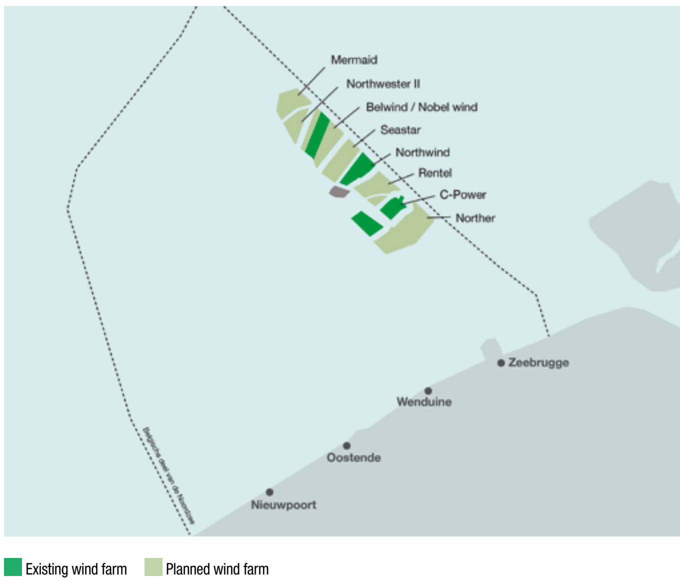
EVOLUTION AND FORECAST OF INSTALLED CAPACITY OFFSHORE WIND (FIG. 38)



GEOGRAPHICAL DISTRIBUTION OF THE BELGIAN ONSHORE WIND PRODUCTION (WINTER 2016-17) (FIG. 37)



OFFSHORE WIND CONCESSIONS IN THE BELGIAN NORTH SEA (FIG. 39)

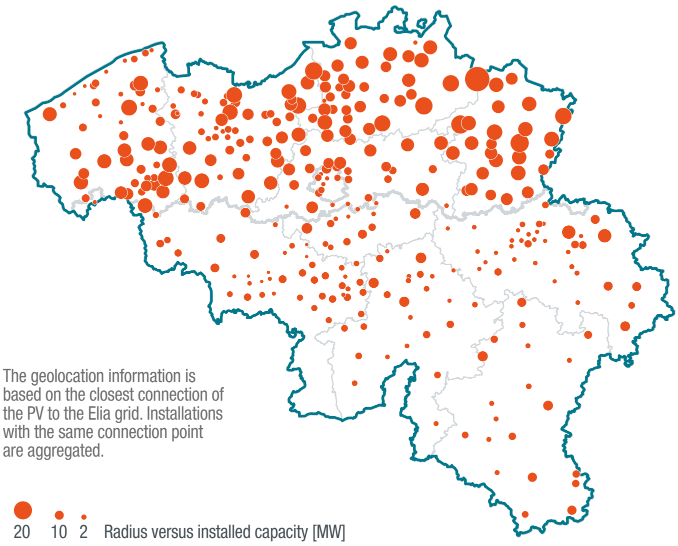


3.1.1.3 SOLAR

Figure 40 shows the historical trend of photovoltaic (PV) installed capacity in Belgium. It also shows the forecast used in this analysis, as consolidated by the FPS Economy. On average, an increase of approximately 200 MW per year is taken into account. By way of illustration, Figure 41 shows the geographical distribution of PV installed capacity in Belgium for the period 2016-17.

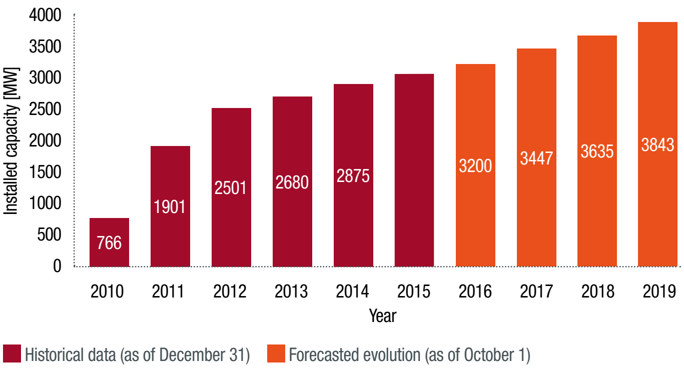
+ 200 MW / YEAR

GEOGRAPHICAL DISTRIBUTION OF THE BELGIAN PHOTOVOLTAIC ELECTRICITY PRODUCTION (WINTER 2016-17) (FIG. 41)



The geolocation information is based on the closest connection of the PV to the Elia grid. Installations with the same connection point are aggregated.

EVOLUTION AND FORECAST OF INSTALLED CAPACITY PV (FIG. 40)



3.1.2 BIOMASS, WASTE AND COMBINED HEAT & POWER FACILITIES

This section elaborates on Belgium's biomass, waste and Combined Heat & Power (CHP) production facilities. In previous adequacy reports, the biomass category also included production units using waste as fuel. The decision was made to split this category in order to increase transparency and improve the quality of the analysis. Firstly, in section 3.1.2.1, sources used in the consolidation of installed capacity for Belgium are given. Next, section 3.1.2.2 provides details of how such production is taken into account in the ANTARES model.

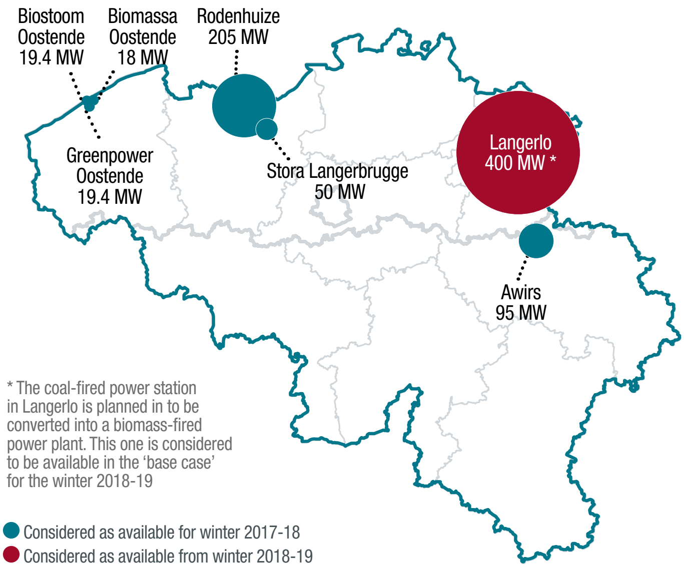
3.1.2.1 INSTALLED CAPACITY CONSOLIDATION FOR BIOMASS, WASTE AND CHP

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. The database includes units subject to a CIPU[27] contract, as well as units for which such a contract does not apply.

When the unit is subject to a CIPU contract, its owner is required to notify Elia about the availability of the unit. The producer must 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 has been agreed with the distribution system operator that all units with an installed capacity greater than 0.4 MW have to be reported to Elia for inclusion in the database. In practice, units with an installed capacity less than 0.4 MW are also reported, either individually or on an aggregated basis. The database contains information on units in service and on projects currently in development.

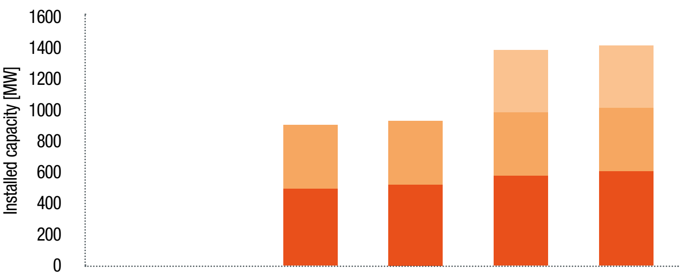
In the same way as for onshore wind and PV (see section 3.1.1), the FPS Economy has consolidated a forecast for installed **biomass** production capacity, after consultation with the regions. This forecast is in line with the information in the Elia database. An increase of 400 MW is taken into account for winter 2018-19, with the commissioning of the biomass conversion of the Langerlo power plant. Also several smaller biomass projects result in an average increase in installed capacity of approximately 40 MW/year. Figure 43 shows the forecasted trend in installed capacity of biomass electricity production in Belgium. The figure differentiates between whether or not a CIPU contract applies to the units, and the planned Langerlo biomass conversion project is listed separately. In Figure 42, biomass production units with a CIPU contract are shown for information.

TOTAL INSTALLED CIPU BIOMASS CAPACITY IN BELGIUM FOR WINTER 2016-17 (FIG. 42)



Total installed CIPU capacity considered in the 'base case' for winter 2017-18: **407 MW**

FORECASTED EVOLUTION OF INSTALLED CAPACITY BIOMASS (FIG. 43)



	2016-17	2017-18	2018-19	2019-20
Langerlo biomass conv.	0	0	400	400
Biomass CIPU (excl. Langerlo)	407	407	407	407
Biomass non-CIPU	496	520	577	607

As suggested in the replies to the public consultation on the Belgian input data, Elia has analysed a sensitivity regarding the commissioning of the Langerlo biomass conversion project. For more information regarding this sensitivity for winters 2018-19 and 2019-20, see section 6.2.2.3.

LANGERLO POWER PLANT ACQUIRED BY ESTONIAN INVESTOR – Source: De Standaard 7 June 2016 (translated)

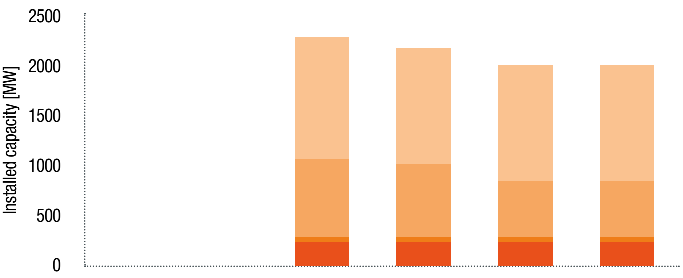
A buyer has been found for the Langerlo power plant. The members of the Works Council were informed yesterday. The new owner of the plant is the Estonian group Graanul Invest, which is also the largest producer of wood pellets in Europe. The acquisition price was not released. [...]

The Langerlo power plant currently has a capacity of 656 MW. When converted to a biomass power plant, at full capacity, it will burn 1.8 million tonnes of wood pellets a year. The conversion should be completed by autumn 2018. The price and conditions of the acquisition by Graanul Invest are confidential.

27. 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.

For **CHP and waste**, it has been agreed with the FPS Economy to base the forecast of the installed capacity on the information available in the Elia production database. Only projects communicated to Elia that are in a sufficiently advanced phase in their development are taken into account in this analysis. In Figure 44, the forecast trend in CHP and waste installed capacity is shown. Again, the figure differentiates between units based on whether or not the unit is subject to a CIPU contract. No development is forecast for the installed capacity of waste-fired units, and a limited decrease of approximately 60 MW is taken into account for CHP units without a CIPU contract. For CHP units with a CIPU contract, a small decrease in installed capacity of 40 MW is forecast between winters 2017-18 and 2018-19. For winter of 2019-20, an additional decrease of 129 MW in installed capacity of CHP units with a CIPU contract is expected compared to winter 2018-19.

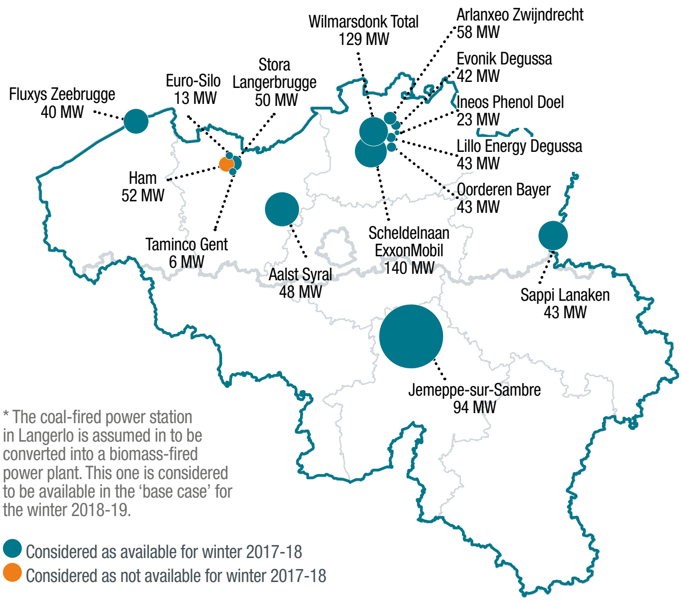
FORECASTED EVOLUTION OF INSTALLED CAPACITY CHP AND WASTE (FIG. 44)



	2016-17	2017-18	2018-19	2019-20
CHP non-CIPU	1216	1157	1157	1157
CHP CIPU	774	722	682	553
Waste non-CIPU	51	51	51	51
Waste CIPU	241	241	241	241

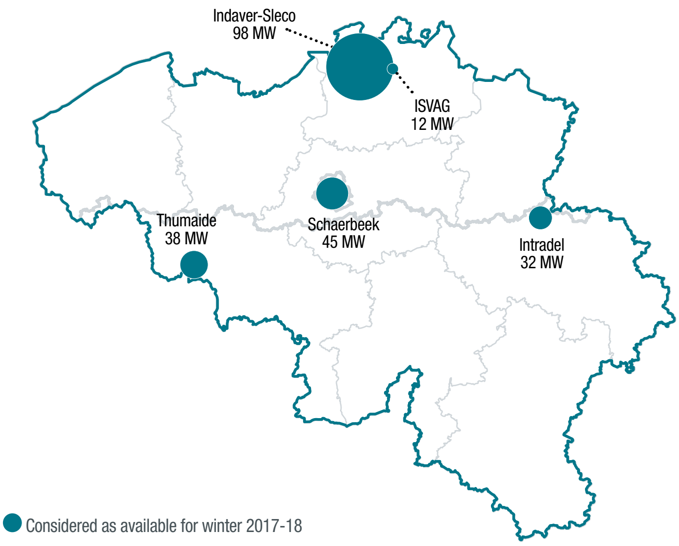
In Figure 45 and Figure 46, the geographical location of the installed capacity of CHP and waste units with a CIPU contract is given by way of illustration.

TOTAL INSTALLED CIPU CHP CAPACITY AVAILABLE IN BELGIUM FOR WINTER 2016-17 (FIG. 45)



Total installed CIPU capacity considered in the 'base case' for winter 2017-18: **772 MW**

TOTAL INSTALLED CIPU WASTE CAPACITY AVAILABLE IN BELGIUM FOR WINTER 2016-17 (FIG. 46)



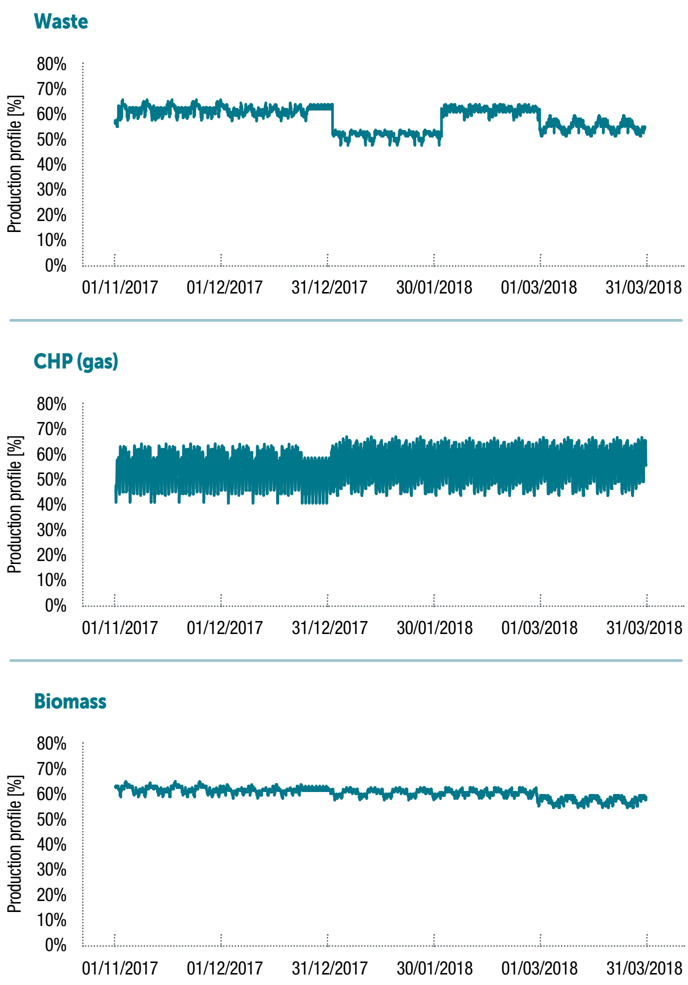
Total installed CIPU capacity considered in the 'base case' for winter 2017-18: **241 MW**

3.1.2.2 BIOMASS, WASTE AND CHP MODELLING APPROACH

In the ANTARES model, biomass, waste and CHP units subject to a CIPU contract are modelled differently from those to which no CIPU contract applies. Units with a CIPU contract are modelled individually, with their specific characteristics in a way similar to other CIPU units. The availability of thermal production with a CIPU contract is discussed in more detail in section 3.1.3.2.

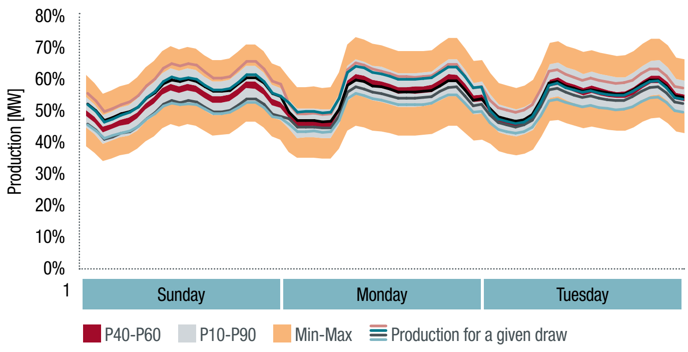
The way in which biomass, waste and CHP units without a CIPU contract are modelled has been improved in comparison to previous reports. For each of these three production types, power output measurement data has been analysed for a period of five years depending on the availability of the data. This gives the average hourly production profiles, displayed in Figure 47. These profiles were also made public in the public consultation on the data used in this analysis (see section 1.5).

HOURLY AVERAGE PRODUCTION PROFILE FOR THE WINTER (FIG. 47)



Based on an analysis of the availability of each of the three production categories, probabilistic outage draws are done, in a similar way as is done for 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 48, 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.

COMBINED CHP, WASTE AND BIOMASS PRODUCTION FOR THE BELGIAN UNITS WITHOUT A CIPU CONTRACT: ILLUSTRATION OF THE DISTRIBUTION FOR A SUNDAY, MONDAY AND TUESDAY (FIG. 48)



3.1.3 THERMAL PRODUCTION WITH A CIPU CONTRACT

This section gives details on Belgian thermal production units with a CIPU contract. For biomass, waste, and CHP production, these units were discussed above in section 3.1.2. Below details are given on the installed capacity of thermal units with a CIPU contract (section 3.1.3.1). 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 3.1.3.2

3.1.3.1 INSTALLED CAPACITY OF THE THERMAL PRODUCTION WITH A CIPU CONTRACT

The installed capacity of Belgian thermal production with a CIPU contract is consolidated by Elia and the FPS Economy on the basis of information provided by the producers to the Federal Minister of Energy, the FPS Economy, the CREG and Elia, as required by law. The aforementioned parties cannot be held accountable for the realisation of the provided hypotheses, since this is the responsibility of the producers. Figure 49 shows the forecast for thermal production units with a CIPU contract.

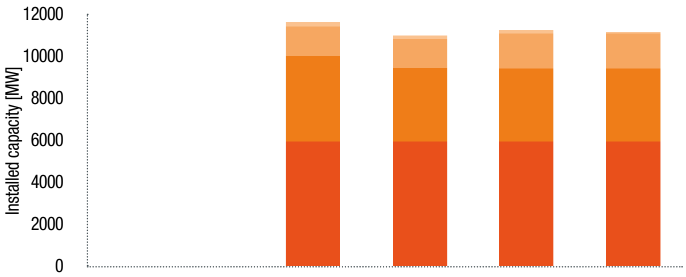
Section 3.1.2 gives the details for Belgian **biomass, waste and CHP** units with a CIPU contract. In April 2016, the decommissioning of the Langerlo coal plant marked the closure of the last big **coal** plant in Belgium.

The hypothesis used in this analysis with regards to **nuclear** installed capacity is in line with the law accepted by the Belgian government on the nuclear phase-out. This law has been amended two times:

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

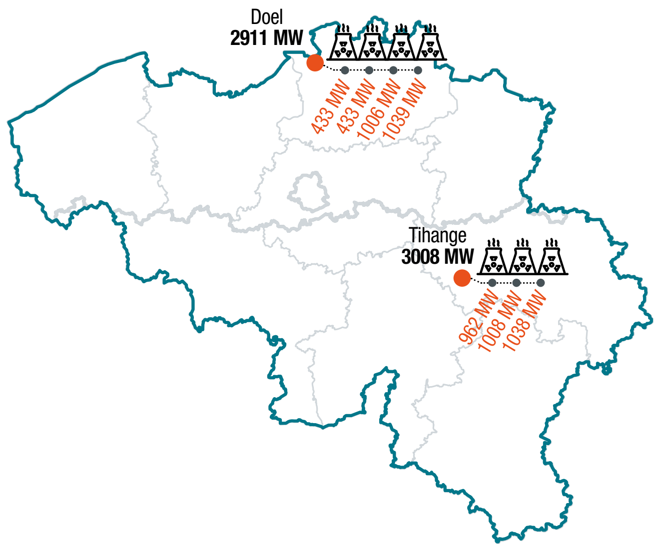
In line with the amended Belgian legislation on the nuclear phase-out, it is assumed that all seven nuclear reactors (5919 MW) are operational for the whole length of the period under study (see Figure 50). A sensitivity to this hypothesis is also studied. See section 6.2.2.4 for more information.

FORECAST OF THE INSTALLED CAPACITY THERMAL UNITS WITH CIPU CONTRACT (FIG. 49)



	2016-17	2017-18	2018-19	2019-20
Turbojet	161	161	161	69
Coal	0	0	0	0
Biomass, CHP and Waste	1423	1371	1602	1602
Gas CCGT and GT	3804	3502	3502	3502
Nuclear	5919	5919	5919	5919

INSTALLED NUCLEAR CAPACITY IN BELGIUM (FIG. 50)

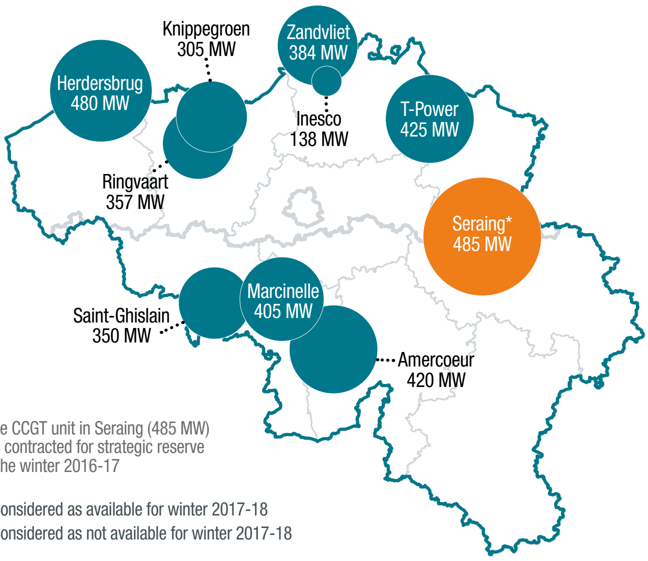


Total installed CIPU capacity considered in the 'base case' for winter 2017-18: **5919 MW**

In line with Belgian legislation on the nuclear phase-out, it is assumed that all seven nuclear reactors (5919 MW) are operational for the whole length of the period under study.

In recent years, several thermal units have been taken out of market due to bad economic conditions. Some of these units were contracted in the context of strategic reserves. For this analysis, it is assumed that all units currently participating in strategic reserves will not return to the market. By way of illustration, the geographical distribution of CCGT and OCGT units in Belgium is shown in Figure 51 and Figure 52 respectively. The installed capacity for turbojet units in Belgium is summarised in Figure 53.

TOTAL INSTALLED CCGT CAPACITY IN BELGIUM FOR WINTER 2016-17 (FIG. 51)



* The CCGT unit in Seraing (485 MW) was contracted for strategic reserve for the winter 2016-17

- Considered as available for winter 2017-18
- Considered as not available for winter 2017-18

Total installed CIPU capacity considered in the 'base case' for winter 2017-18: **3264 MW**

Based on the feedback received at the public consultation, for Belgian data, Elia decided to analyse a sensitivity to thermal installed capacity for winters 2018-19 and 2019-20 by removing around 600 MW. See section 6.2.2.1 for more information on this sensitivity.

ART.4 BIS §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 shutdown 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 shutdown. A temporary shutdown can only occur after 31 March of the year following the notification referred to in paragraph 1.*

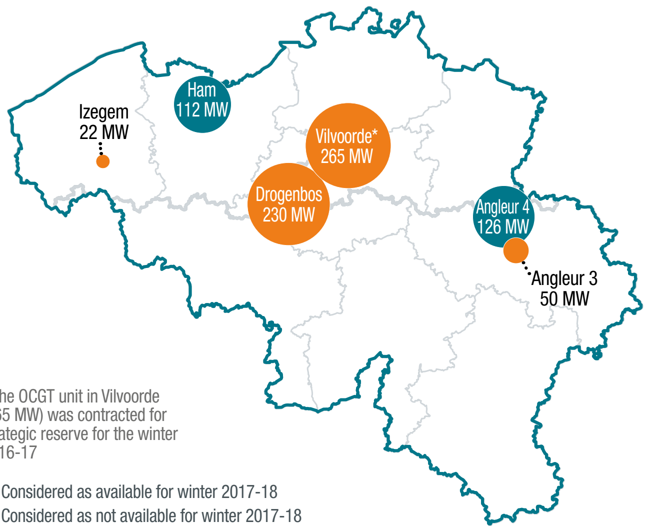
A permanent shutdown can only occur after 30 September of the year following the notification referred to in paragraph 1. A notice of shutdown is required for each installation for power generation connected to the transmission grid, whether a prior individual authorisation in accordance with Article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

__§ 2.__ At the recommendation of the commission and 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 shutdown, 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.'

TOTAL INSTALLED OCGT CAPACITY AVAILABLE IN BELGIUM FOR WINTER 2016-17 (FIG. 52)

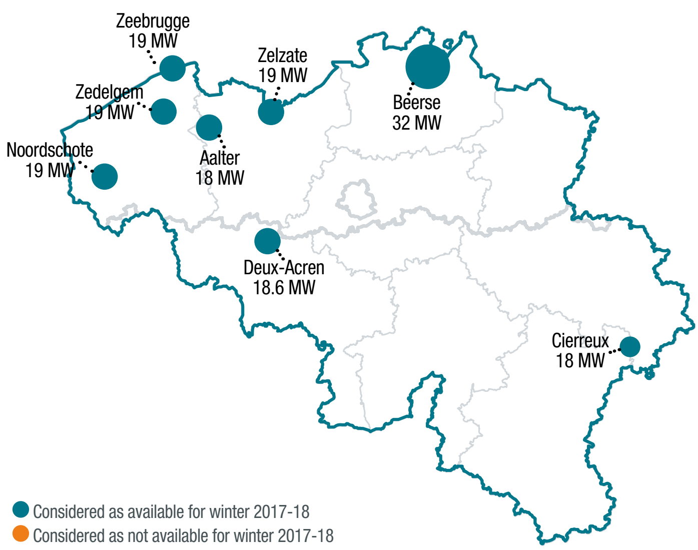


* The OCGT unit in Vilvoorde (265 MW) was contracted for strategic reserve for the winter 2016-17

- Considered as available for winter 2017-18
- Considered as not available for winter 2017-18

Total installed CIPU capacity considered in the 'base case' for winter 2017-18: **238 MW**

INSTALLED TURBOJET CAPACITY AVAILABLE IN BELGIUM FOR WINTER 2016-17 (FIG. 53)



- Considered as available for winter 2017-18
- Considered as not available for winter 2017-18

Total installed CIPU capacity considered in the 'base case' for winter 2017-18: **161 MW**

3.1.3.2 AVAILABILITY OF THE THERMAL PRODUCTION WITH A CIPU CONTRACT

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 2.1.2), based on historical availability rates. This way, a very high sequence of 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**, generally for maintenance; and
– **unplanned unavailability**, usually caused by an unexpected malfunctioning of the unit.

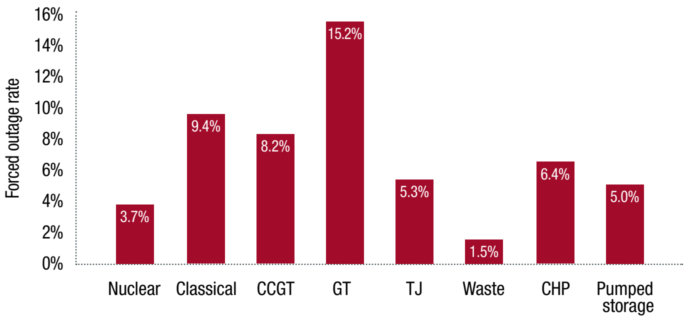
PLANNED UNAVAILABILITY

In recent years, less and less maintenance is planned during the winter. Together with the producers, Elia aims to schedule all planned unavailability outside the winter period (see also box *Method and hypotheses used for the calculation of the maximal maintenance curve*). A maintenance schedule has already been established for 2017, and is taken into account in the analysis for winter 2017-18. For the rest of the winter, the maintenance schedule is not yet known, and no planned unavailability of CIPU units is considered. Similarly, for the analysis for winters 2018-19 and 2019-20, no planned outages were considered in the course of the winter.

UNPLANNED UNAVAILABILITY

As mentioned above in section 2.1.2, in addition to planned unavailability, this study takes into account unplanned or forced unavailability. An analysis has been conducted for each production type (e.g. CCGT, gas turbine, turbojet, etc) based on the historical unplanned unavailability for the period 2006 to 2015. The analysis is conducted using the availability information for production units that are nominated on the day-ahead market and the result is shown in Figure 54.

AVERAGE FORCED OUTAGE RATE OVER 2006-15 PER PRODUCTION TYPE (FIG. 54)



The unavailability of nuclear units Doel 4 (August 2014 to December 2014), Doel 3 and Tihange 2 (March 2014 to December 2015) are not taken into account in the determination of forced outage rates. Given the exceptional nature of this unavailability, the decision was made to analyse such events as a sensitivity instead.

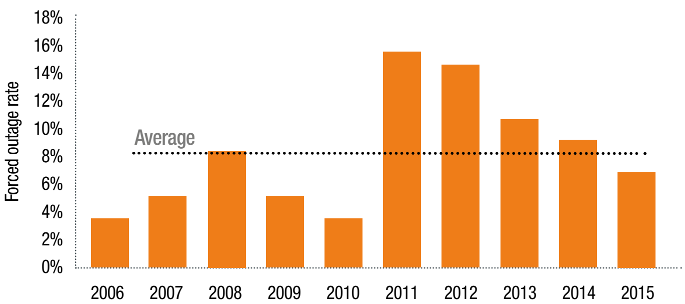
In recent years, Belgium has faced an exceptionally high unavailability of its nuclear power plants. To assess the impact of a major nuclear outage on security of supply, a sensitivity was analysed where 2 GW of nuclear power plants were unavailable for the whole winter.
See section 6.2.2.4 for more information on this analysis.

The analysis of forced outage rates of Belgian generation units has shown that the outage rate can differ greatly from one year to the next. In Figure 55 and Figure 56, this variability is illustrated for CCGT and nuclear generation units respectively. It can be seen that the forced outage rate for Belgian CCGT units has been dropping steadily in recent years. One possible explanation for this is the fact that the older combined cycle gas turbines have been taken out of operation. At the end of 2017, the average age of operational Belgian CCGT units will be approximately 13 years (see also Figure 57). This figure also shows the installed CCGT capacity that is currently in operation, in the strategic reserves or considered to be out of operation for winter 2017-18.

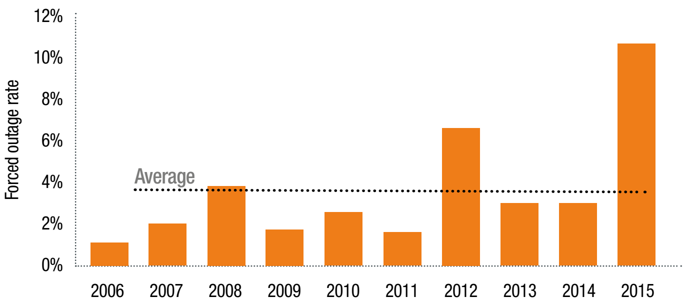
For Belgian nuclear power plants, Figure 56 shows that there is also a wide variation in the forced outage rates over the years. Elia has analysed a sensitivity on its 'base case' for the three winters under study with higher forced outage rates for CCGT and nuclear power plants. More specifically, for these two production types the sensitivity takes into account the maximum observed forced outage rate over the last ten years.

Due to the variation in outage rates and the very high forced outage rate of nuclear units during the course of 2015, a sensitivity has been performed on the assumptions regarding the outage rates for the Belgian nuclear and CCGT units taking the maximum value observed in the past 10 years. See section 6.2.2.2 for more information concerning this sensitivity.

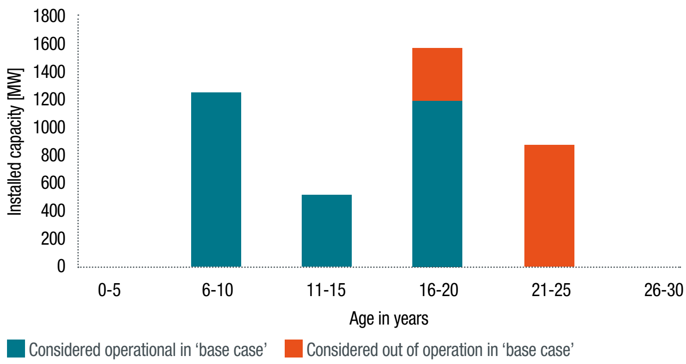
FORCED OUTAGE RATE FOR BELGIAN CCGT POWER PLANTS PER YEAR (FIG. 55)



FORCED OUTAGE RATE FOR BELGIAN NUCLEAR POWER PLANTS PER YEAR (FIG. 56)



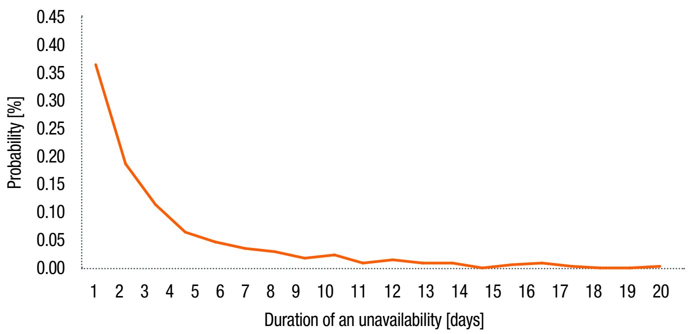
AGE OF THE BELGIAN CCGT UNITS AT THE END OF 2017 (FIG. 57)



In addition to the analysis regarding the frequency at which unplanned outages happen, the length of such outages has also been studied. For unavailability of a limited duration (i.e. intra-day outages), the balancing reserves can be used (see also section 3.1.5). Therefore, these outages do not have to be taken into account when calculating the required strategic reserve volume.

For each type of production unit, the duration probability of an unplanned unavailability is modelled separately. The analysis of the historical length of forced outages shows that the unavailability of a limited number of days is more common. However, unplanned unavailability of a longer duration can also occur, as illustrated in Figure 58.

EXAMPLE: DISTRIBUTION OF THE DURATION OF AN UNAVAILABILITY FOR ONE TYPE OF PRODUCTION UNITS (BASED ON THE ANALYSIS OF HISTORICAL DATA) (FIG. 58)



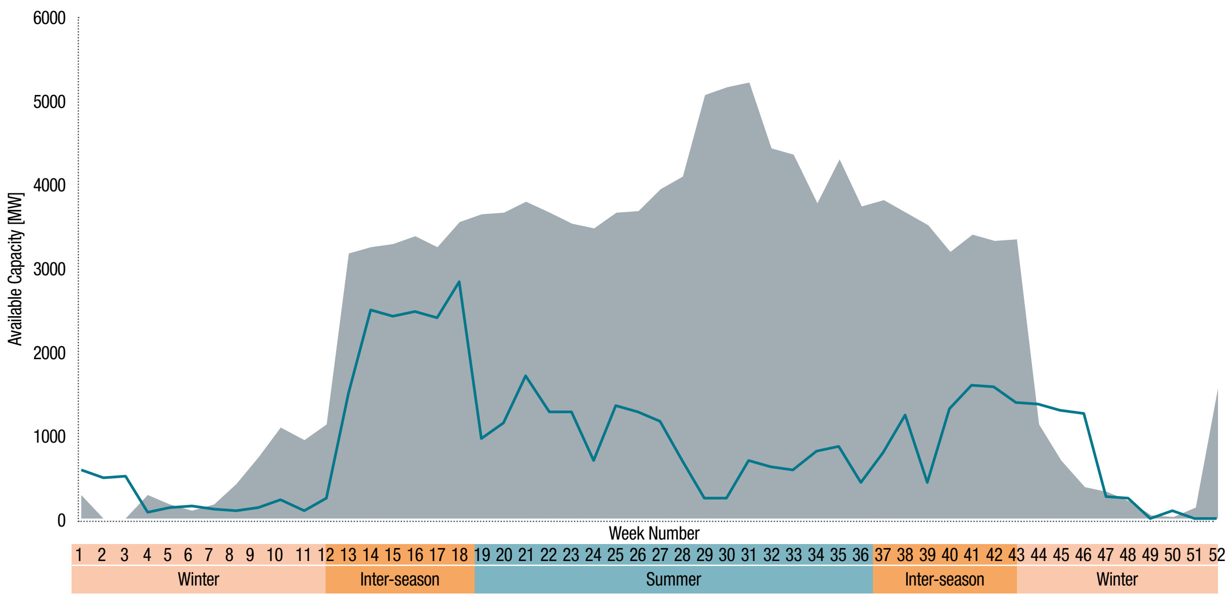
METHOD AND HYPOTHESES USED FOR THE CALCULATION OF THE MAXIMAL MAINTENANCE CURVE

Every year, on a fixed date, the Access Responsible Parties (ARP) submit a proposed maintenance schedule for their production units to the Transmission System Operator (TSO). If a risk of punctual or structural scarcity is identified, the TSO has the option of modifying these maintenance schedules with the goal of ensuring security of supply:

- The **maximal maintenance** curve of Belgian production units is developed by the TSO on an annual basis. This curve, covering a complete calendar year, indicates for each week the total production capacity that can be in maintenance. It is constructed via a **probabilistic analysis**, taking into account the following adequacy criterion: the 95th percentile of the remaining available capacity that can be in maintenance, calculated on an hourly basis. **Elia uses the same type of model and the same hypotheses** as used in the process of determining the required of strategic reserve volume, but modified to cover a complete calendar year.
- The TSO's acceptance or refusal of a maintenance schedule submitted by the ARP is determined by the risk of shortage. The risk of shortage is evaluated by comparing two parameters: the volume available for revision (V_{P95}) and the volume for maintenance as proposed by the ARP (V_R). When there is a **small risk of shortage** ($V_R < V_{P95}$, with only sporadic risk of shortage), Elia will ask the ARP to modify their maintenance schedule in order to minimise the sporadic risks. In the second case, where a **high risk of shortage** is identified, Elia will ask the ARP to modify the maintenance schedule so that the risk is spread out over the year. In both cases, decisions are made in consultation with the ARP in question.

By way of illustration, Figure 59 shows the result of the abovementioned exercise for 2017. The grey area shows the maximal maintenance curve, with the solid line indicating the scheduled maintenance planning at the moment.

WEEKLY AVAILABLE CAPACITY FOR ARP REVISION PLANNING (FIG. 59)



3.1.4 HYDROELECTRIC POWER STATIONS

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

- pumped-storage units;
- run-of-river units.

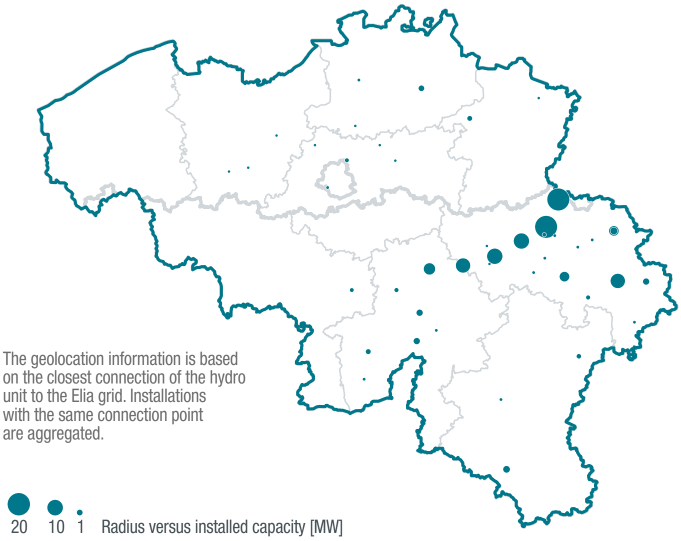
Belgium has ten **pumped-storage** units, six at the Coo power station and four at the La Platte Taille power station. The total installed turbining capacity amounts to 1308 MW, with the combined storage capacity equalling approximately 5800 MWh. Pumped-storage units are typically used to provide ancillary services. Therefore, the total reservoir capacity used for economic dispatch in this analysis is derated 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 are modelled individually which makes it possible to take into account planned and forced outages of these units. The model determines the dispatching of units using a daily cycle, taking into account the hourly electricity price (optimal economic dispatch, see section 2.1.2). When the pumped-storage units pump water into the reservoir, the necessary power for this can be considered an additional consumption. Similarly, the turbining of water adds up to the Belgian electricity production. The historical use of the pumped-storage power plants in Belgium is in line with the model results.

When the model encounters periods of structural supply shortage (with prices as high as 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 out peaks in electricity use.

Run-of-river power stations in Belgium had an installed capacity of 114 MW at the end of 2015. For information purposes, Figure 60 shows the geographical distribution of this type of production for the end of 2016. According to the information available to Elia, a very slight increase in such capacity is expected, resulting in an installed capacity of 117 MW at the end of 2017. As described in more detail in section 2, run-of-river power stations are taken into account in the model by using 40 monthly historical profiles.

GEOGRAPHICAL DISTRIBUTION OF THE BELGIAN RUN-OF-RIVER ELECTRICITY PRODUCTION (WINTER 2016-17) (FIG. 60)



3.1.5 BALANCING RESERVES

Within the context of its legal obligations, more specifically in accordance with Article 8, §1 of the Electricity Act, Elia is obliged to contract ancillary services to ensure a secure, reliable and efficient electricity grid [43]. 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 must be possible to deploy the balancing reserves to restore deviations independently from the strategic reserve, the volume contracted for production capacity for frequency containment reserves and frequency restauration reserves is taken into account in the simulations as a reduction in available capacity to cope with adequacy (the reserve requirements for BRPs that have production units higher than the standard production unit capacity is also included). There is a decrease in the volume of balancing reserves for Belgian production units taken into account for this study (based on the needed volume for 2017) in comparison with the value taken for the previous study for winter 2016-17 (based on the contracted capacity for 2016).

The amount of balancing reserves needed for 2017 was proposed by Elia and approved by the Belgian regulator (CREG). The approval document can be found on CREG's website [25].

FCR – FREQUENCY CONTAINMENT RESERVE ('PRIMARY RESERVE'):

The objective of primary frequency control is to maintain the balance between generation and consumption within the high-voltage European interconnected system. This reserve is defined at ENTSO-E level for the European synchronous area and is not known yet for 2017 as of this writing. In this study it is assumed that it should be **around 80 MW**. Considering that a proportion has been contracted on demand as of mid-2016, and that FCR can be contracted abroad, **20 MW** of FCR is considered as being sourced on Belgian production units as of 2017.

aFRR – AUTOMATIC FREQUENCY RESTAURATION RESERVE ('SECONDARY RESERVE'):

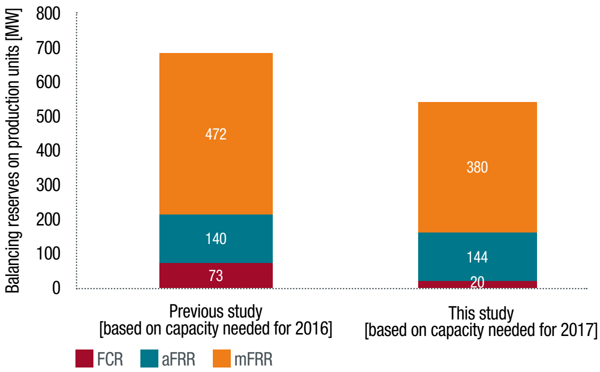
144 MW are assumed as being provided by Belgian production units for 2017 onwards. Given the specific requirements of this reserve, it is mainly production units that provide this type of reserve.

mFRR – MANUAL FREQUENCY RESTAURATION RESERVE ('TERTIARY RESERVE'):

Tertiary reserve products can be either provided by demand or production. The amount considered is the volume that should be provided by production units and the reserve requirements for BRP that have production units higher than the standard production unit capacity is **380 MW**.

By way of illustration, Figure 61 shows the considered balancing reserves to be provided by Belgian production units for this study for each type of reserve. More information about these types of reserves can be found on Elia's website [26].

BALANCING RESERVES CONSIDERED AS PROVIDED BY BELGIAN PRODUCTION UNITS IN THIS STUDY (FIG. 61)



Strategic and balancing reserves are used for different goals. This does not mean that Elia will not use the balancing reserves to prevent load-shedding. Applying balancing reserves is one of the measures that can be taken if there is a risk to security of supply (see section 1.4.3).

3.2 ELECTRICITY CONSUMPTION IN BELGIUM

The hourly total electrical load is forecasted for the next three winters. The consumption profile is also constructed for all the simulated countries and can be divided into three steps as shown on Figure 62.

STEPS TO CONSTRUCT CONSUMPTION PROFILE (FIG. 62)

1. GROWTH OF THE TOTAL DEMAND
2. GROWTH APPLIED TO AN HOURLY NORMALISED PROFILE FOR TEMPERATURE
3. THERMOSENSITIVITY FOR TEMPERATURE IS ADDED FOR EACH HOUR OF THE WINTER

This results in 40 hourly total load profiles for each country.

WHAT IS TOTAL ELECTRICAL CONSUMPTION ('TOTAL LOAD')?

Total electrical consumption takes into account all loads on the Elia grid and all 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 computation, measurements and extrapolations.

WHAT ARE THE DIFFERENCES COMPARED TO ELIA CONSUMPTION ('ELIA GRID LOAD')?

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 in recent years. Therefore Elia decided to supplement 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 SOTEL/TWINERG CONSUMPTION IN LUXEMBOURG TAKEN INTO ACCOUNT?

The Elia grid includes grids with voltages of at least 30kV in Belgium as well as in the Sotel/Twinerg grid in the south of Luxembourg. In this study Belgium's total load excludes the Sotel/Twinerg grid consumption. Such consumption is modelled as a separate load connected to Belgium. More information can be found in section 4.5.

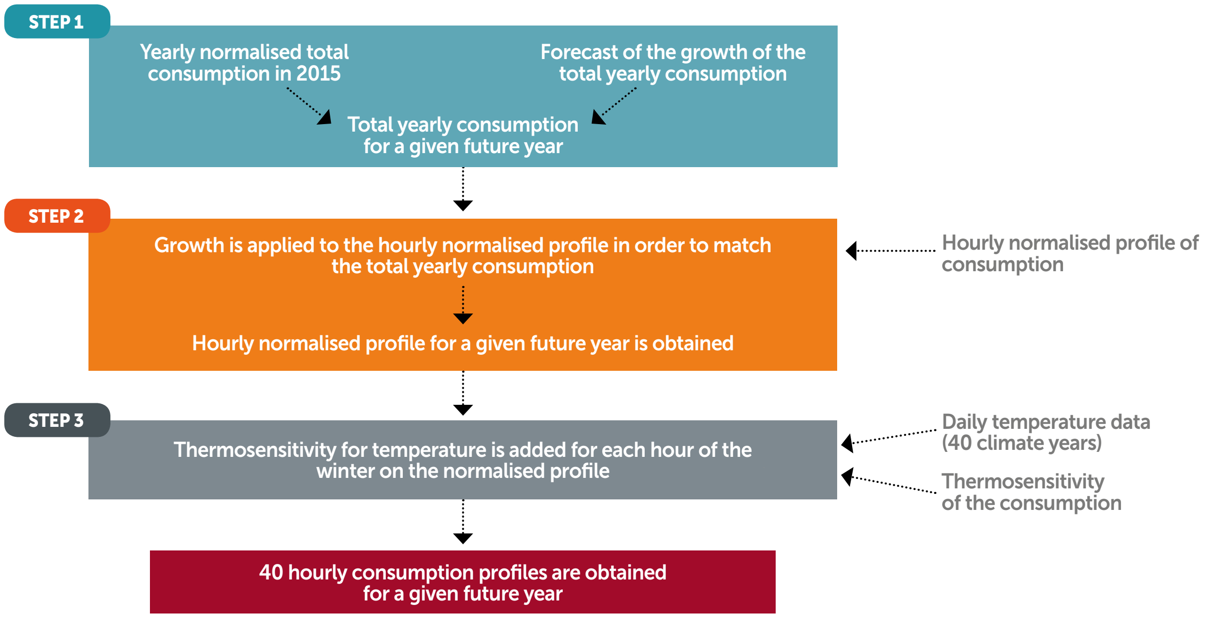
WHAT IS PUBLISHED ON ELIA'S WEBSITE?

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 [28].

Figure 63 gives a detailed overview of the construction process. The three steps are detailed in sections 3.2.1, 3.2.2, and 3.2.3.

CONSTRUCTION OF THE HOURLY CONSUMPTION PROFILES (FIG. 63)



3.2.1 GROWTH IN TOTAL BELGIAN LOAD

1 GROWTH OF THE TOTAL DEMAND

The first step consists of forecasting the annual total electrical load for a given country. After the normalisation of the 2015 total load for temperature, an estimation of the growth of total demand is taken.

Annual normalised demand fluctuations are mainly due to economic indicators (GDP, growth of population, industry, etc.), energy efficiency improvements and electrification (new usage of electricity, switching between energy sources). The most recent forecast by the IHS CERA[28], a consultancy firm, is used as a reference for this study. A high sensitivity to this value will also be evaluated taking into account the average annual growth (2015-2020) in demand compared to the EU reference scenario for 2016.

A decrease in demand growth can be observed for the 'base case' scenario. This is due to energy efficiency measures and to the economic forecasts that were downgraded after the announcement of a possible 'Brexit'. Other studies and forecasts show a possible decrease in electrical consumption for the next five years and beyond [27] [47].

Figure 64 gives an overview of annual total demand since 2010 and its value normalised for temperature. The table also includes both forecasts ('base case' and 'high growth') as well as the forecast taken for the previous study.

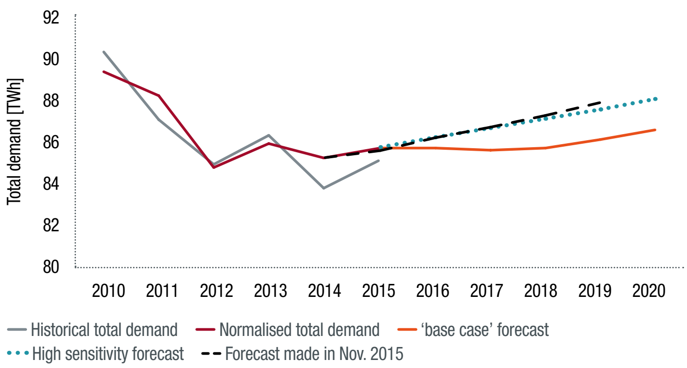
OVERVIEW OF THE YEARLY TOTAL DEMAND SINCE 2010 AND ITS NORMALISATION FOR TEMPERATURE (FIG. 64)

		Historical values			'Base case' total demand		High sensitivity total demand		Forecast Nov. 2015
		Total demand (TWh)	Normalised total demand (TWh)	Growth rate	Growth rate	Forecast (TWh)	Growth rate	Forecast (TWh)	Forecast (TWh)
historical	2010	90.20	89.27						
historical	2011	87.02	88.17	-1.23%					
historical	2012	84.86	84.66	-3.97%					
historical	2013	86.24	85.81	1.36%					
historical	2014	83.73	85.14	-0.78%					85.14
historical	2015	85.01	85.64	0.58%		85.64		85.64	85.51
forecast	2016				0.00%	85.64	0.54%	86.10	86.11
forecast	2017				-0.17%	85.50	0.54%	86.56	86.66
forecast	2018				0.12%	85.60	0.54%	87.03	87.22
forecast	2019				0.56%	86.08	0.56%	87.52	87.83
forecast	2020				0.60%	86.60	0.60%	88.05	

28. IHS CERA: Information Handling Services Cambridge Energy Research Associates

Those values are also plotted on a chart as shown on Figure 65. Given the fact that 2015 was warmer than the average, it leads to a normalised consumption that is higher than the historical observed value. Both demand forecasts scenarios show a range of around 2 TWh for the 2020 time-frame between the 'high growth' and 'base case' scenarios. In addition to this range, a climatic range due to the temperature sensitivity of the load will be applied.

TOTAL BELGIAN DEMAND HISTORICAL AND FORECAST OF THE NORMALISED DEMAND (FIG. 65)



Elia analysed the impact of high Belgian demand growth on the security of supply. For more information regarding this sensitivity, see section 6.2.1.2.

3.2.2 LOAD PROFILE NORMALISED FOR TEMPERATURE

2 GROWTH APPLIED TO AN HOURLY NORMALISED PROFILE FOR TEMPERATURE

Once the total annual normalised demand is forecasted for future years, an hourly consumption profile can be constructed. To compute it, a normalised profile for Belgian consumption is taken. This typical profile gives, for every hour of the year, the expected demand based on historical data and on the average historical temperatures observed. This profile is called the profile normalised for temperature.

The growth identified in step 1 is applied to this normalised profile in order to match the total demand forecasted. The hourly normalised profile is shown on Figure 66.

HOURLY NORMALISED LOAD PROFILE FOR BELGIUM FOR WINTER 2017-18 (FIG. 66)

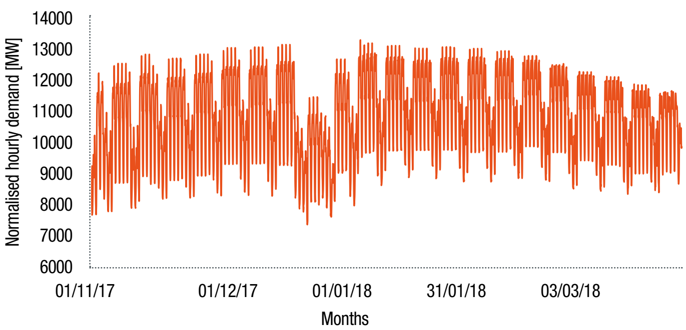


Figure 66 clearly shows the effects week/weekend and holiday effect on consumption. Based on that profile, the peak demand is observed in the second week of January. This peak demand is only valid for a normalised temperature. Applying temperature sensitivity to this profile will lead to very different 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. In section 3.1.4, more details are provided concerning Belgian pumped-storage units.

The impact of market response is not taken into account in this profile either. Market response is modelled separately and optimised by the model based on the prices. More information on market response can be found in section 3.2.4.

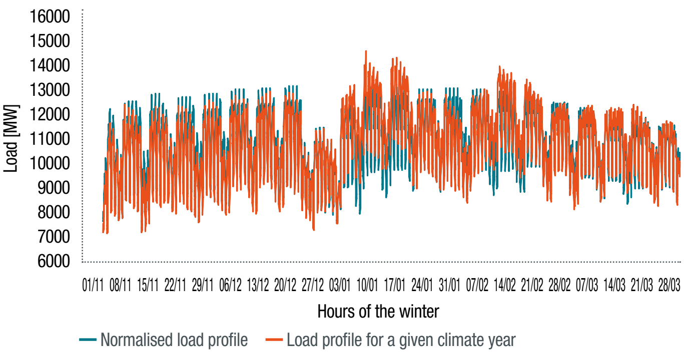
In order to construct the normalised profile for consumption, historical data are used. Special days are flagged so that they are not taken into account in this analysis in order to avoid wrongly forecasting the total load (for example, strikes which lowered consumption, balancing reserves activation, or times when market response was used in the market). The normalised profile therefore represents the country's total load, excluding market response.

3.2.3 SENSITIVITY OF THE LOAD TO TEMPERATURE

3 THERMOSENSITIVITY FOR TEMPERATURE IS ADDED FOR EACH HOUR OF THE WINTER

The last step consists of applying temperature sensitivity to the hourly normalised profile. In this way, 40 historical daily temperatures are used in this computation. For each climate year an hourly profile for consumption is created. Figure 67 shows the impact of temperature on the total hourly profile for Belgium for one of the 40 historical years used as climatic year.

EXAMPLE OF A LOAD PROFILE ON WHICH THERMOSENSITIVITY OF THE DEMAND WAS APPLIED COMPARED TO THE NORMALISED PROFILE (FIG. 67)



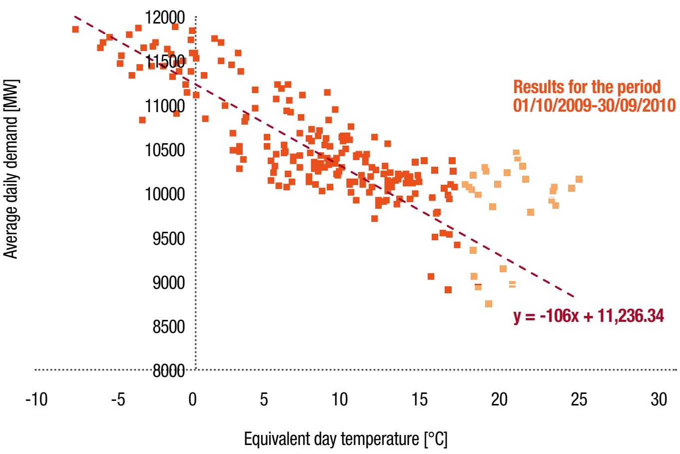
The thermosensitivity of the demand in Belgium is 110 MW/°C on average. This means that a temperature decrease by 1 degree in comparison to the normalised temperature of a given day has an impact of around +110 MW on consumption. This is mainly due to the use of electrical heating in Belgium.

This temperature sensitivity is based on a historical data analysis of total load and equivalent day temperature[29].

29. 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).

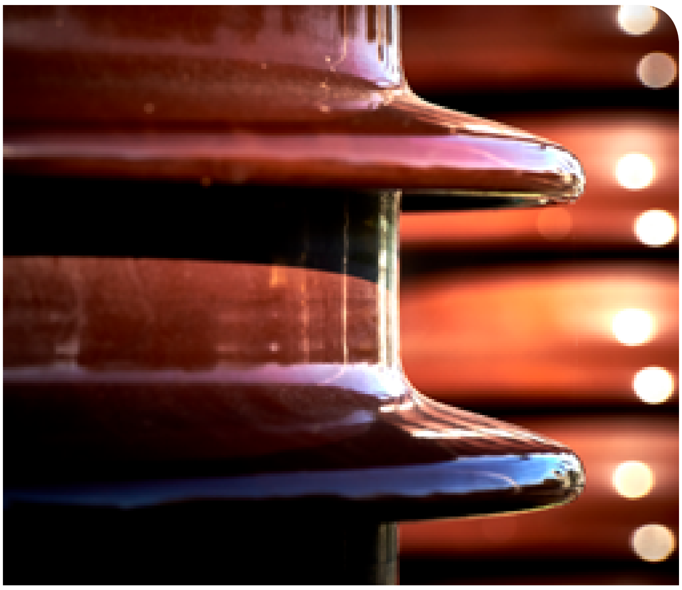
Figure 68 shows the correlation between daily average load and equivalent daily temperature for a given winter where thermosensitivity was around 106 MW/°C. Repeating this exercise for different years gives an average of thermosensitivity of 110 MW/°C for Belgium's total load.

DEMAND THERMOSENSITIVITY (FIG. 68)



Even if this value might seem limited for Belgium, the impact is greater in other countries such as France where electrical heating is even more developed. French sensitivity to temperature is around 2400 MW/°C [47]. Due to the high correlation of temperature between Belgium and France (meteorological conditions being very linked due to geographical proximity), it is a very important element to be taken into account for an adequacy assessment. More information on French hypotheses is given in section 4.1.

A decrease of 1 °C in Belgium leads to an average increase of 110 MW in total electricity demand.



FORECAST OF PEAK DEMAND IN BELGIUM FOR WINTER 2017-18

Figure 69 gives an overview of the peak demand after applying the 40 climate years to the normalised profile. The peak demand is the maximum demand observed for a given winter or year. It gives an indication of the maximum, but not of the occurrence of high demand values. During the winter period more than one cold spell could be observed, the length of which is also a very important parameter. If high demand is observed on only a few days, it will have a lower impact than if a cold spell lasts two weeks. Looking only at the peak demand of each of the 40 climate years, it leads to a peak of 13.5 GW for the 50th percentile (probability of once every two years). In extreme cases, the peak demand could be even higher as shows the 1 out of 20 probability (95th Percentile) that equals 14.1 GW.

PEAK LOAD DISTRIBUTION FOR THE 40 CLIMATE YEARS FOR BELGIUM FOR THE WINTER 2017-18 (FIG. 69)

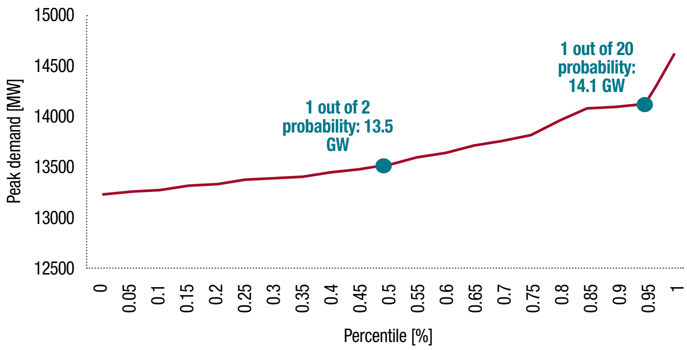
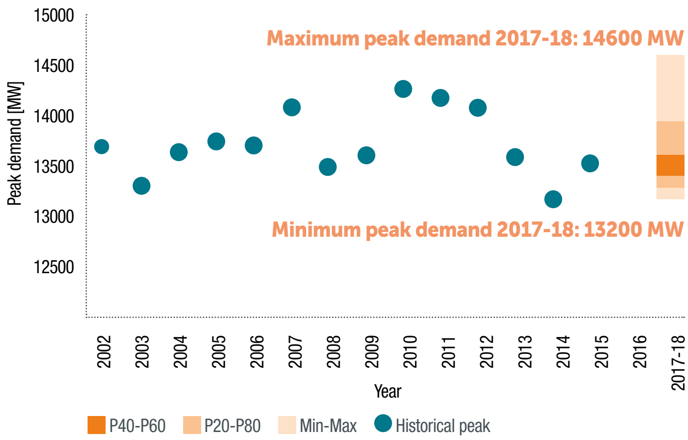


Figure 70 shows historical peak demands[30] since 2002. Note that peak demand is not constant and is mainly influenced by temperature. The graph also shows the percentiles of probability for peak demand in winter 2017-18.

HISTORICAL PEAK LOADS IN BELGIUM AND FORECAST FOR 2017-18 (FIG. 70)



Peak demand for winter 2017-18 is forecasted to be between 13.2 GW and 14.6 GW depending on the climatic conditions.

3.2.4 MARKET RESPONSE

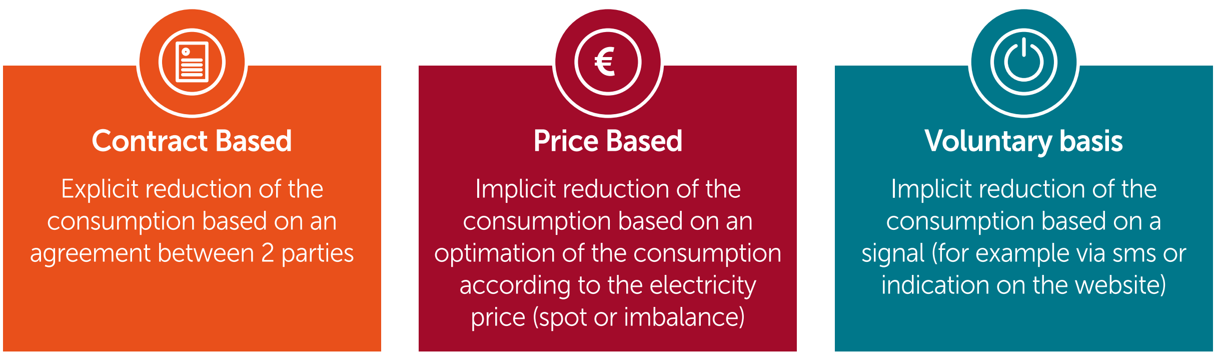
In the previous volume report for winter 2016-17 Elia included an estimation on market response in Belgium to be taken into account in determining strategic reserve volume.

In cooperation with Pöyry, an external and internationally recognised consultancy firm, a survey was organised in 2015. The goal was to refine the hypotheses about the potential market response for winter 2016-17 in situations of exceptional consumption on the day-ahead electricity market, during which prices can reach the price cap of 3000 €/MWh.

In the survey, grid users, balance responsible parties and aggregators active in Belgium were questioned. Through the questions, necessary safeguards are introduced to avoid duplication and to ensure data confidentiality.

The survey investigated three types of flexibility that are present in the market: load reduction based on contracts, based on prices and based on a voluntary mechanism (see Figure 71). The results focus on the flexibility that can be used by market participants, not the volumes that can be contracted by Elia and activated by Elia as part of the balancing reserves and strategic reserve.

3 TYPES OF FLEXIBILITY IN THE MARKET (FIG. 71)



30. The peak demand is an estimation based on measurements and calculations.

During the public consultation held in June 2016 (see also section 1.5) there was a request to update the data on market response during 2016 for winter 2017-18. Since data should be ready by September 2016, it was decided to organise, during the summer, an update of the study performed in 2015. Consequently, due to the short time-frame, there was no possibility of addressing the subject modelling with a new approach, but only of re-using the existing templates and leveraging respondents' experience.

Figure 72 gives an overview of the results of the study for this year, compared to the results for 2015. A distinction is made between flexibility for TSO and DSO grid users. The results of the study come directly from the replies to the survey, after applying a limited number of corrections based on checks.

During the meeting of the Task Force 'Implementation Strategic Reserve' on 19 September 2016, the results of the study were presented by Pöyry [11]. The results show an overall decrease in the stated flexibility, which can be attributed to minor changes by a few respondents. Despite the fact the survey results show a lower flexibility compared to 2015, there is no evidence that the 2015 assumptions regarding flexibility in the Belgian market needs to be changed. It seems that there is less threat of volatility in commodity prices due to the return of nuclear power plants in Belgium, resulting in lower interest in flexibility. During the meeting, it was agreed with the market parties that the values from the 2015 study would be used in the 'base case' scenario and that a sensitivity analysis would be performed on the results of the 2016 study.

FLEXIBILITY ON THE MARKET : RESULTS FROM THE STUDY MADE BY PÖYRY (FIG. 72)

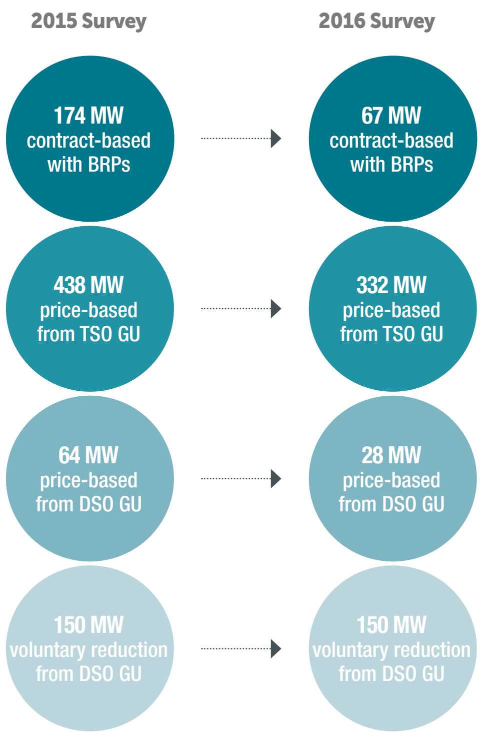
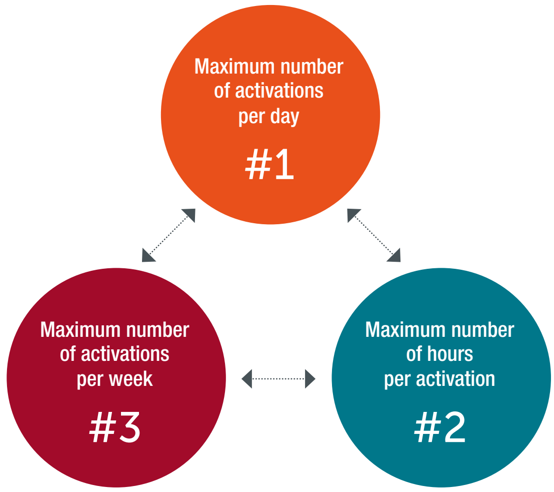


Figure 72 gives only an overview of total flexibility in the market in MW. However, the survey reveals that this potential is subject to a number of limitations, including a limited number of activations per year, a limited number of hours of use when activated and the price on Belpex or imbalance price. This means that it is not possible to simply sum up the different responses from the survey as input for the model. Consideration should be given to such restrictions in the modelling.

Figure 73 gives an overview of the constraints used in the model. This assumption is made on the basis of the analysis by Pöyry of the different responses to the survey.

FLEXIBILITY ON THE MARKET : LIMITATIONS (FIG. 73)



For the model, this means in practice that both flexibility in MW and limitations in usage should be taken into account. How flexibility is used in the model depends, amongst others, on the price and the number of hours of structural deficit. During the hours of structural deficit, when high prices are to be expected, the additional market flexibility will be deployed before proceeding to a situation where the energy supply is not met.

Given these limitations, additional flexibility cannot offer a solution at all times of structural deficit. The deployment of available flexibility will be optimised by the model. This can be seen as an output from the model. A detailed analysis of how the market response is used in the simulations is given in section 6.1.1.4

As a result of the study update on market response this year, it has been concluded that for future volume assessments the methodology should be improved and/or changed.

The impact of the low availability of market response in Belgium on the country's security of supply with the values from the survey performed in 2016 has been analysed in a sensitivity. Please see section 6.2.1.1 for the results of this analysis.

3.3 SUMMARY OF THE ELECTRICITY SUPPLY AND CONSUMPTION IN BELGIUM

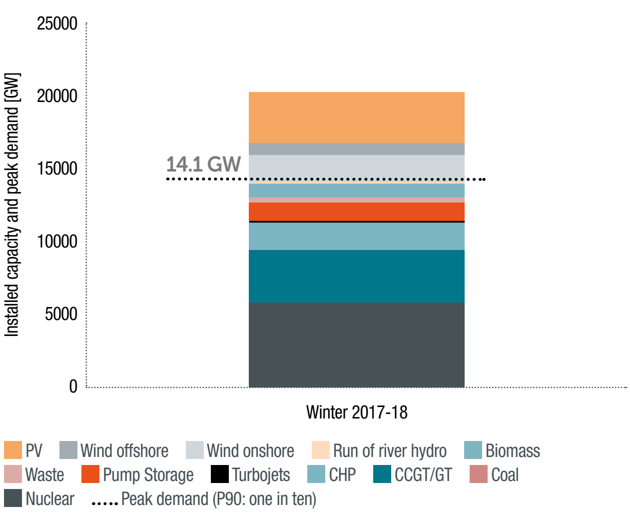
Figure 74 summarises the forecasted installed generation capacity in Belgium taken into account in the 'base case' scenario for the next three winters and gives an overview of historical installed capacities in the previous two winters. Note that this installed capacity does not take into account forced or planned outages, or the energy limitations of some technologies.

INSTALLED GENERATION CAPACITY IN THE MARKET (EXCLUDING CONTRACTED STRATEGIC RESERVE) (FIG. 74)

		Production capacity in winter available in the market (MW)				
		2015-16	**2016-17**	**2017-18**	**2018-19**	**2019-20**
Non RES	Nuclear	5919	5919	5919	5919	5919
	Coal	470	0	0	0	0
	CCGT/GT	4102	3804	3507	3507	3507
	CHP	2031	1990	1879	1839	1710
	Turbojets	179	161	161	161	69
Storage	Pumped-storage	1308	1308	1308	1308	1308
RES	Waste	292	292	292	292	292
	Biomass	946	903	927	1384	1414
	Run of river hydro	114	114	115	116	117
	Wind onshore	1528	1696	1857	2047	2236
	Wind offshore	700	713	862	1142	1996
	PV	3038	3200	3447	3635	3843
	Total	**20632**	**20133**	**20274**	**21350**	**22411**

Combining installed generation capacity with the P90 peak demand forecasted in Belgium for winter 2017-18, Figure 75 can be constructed. In addition to these capacities, market response when prices are high with a total amount of 826 MW should be considered (with activation limits). Imports (see chapter 5 for detailed information) are not shown in this figure.

INSTALLED GENERATION CAPACITY IN THE MARKET AND P90 PEAK DEMAND IN BELGIUM FOR WINTER 2017-18 (FIG. 75)



04

ASSUMPTIONS FOR NEIGHBOURING COUNTRIES

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.

In order to do this, the data and assumptions for the neighbouring countries are coordinated through bilateral contacts with the respective TSOs. For the non-neighbouring countries included in the model, data are collected by using regional or European joint studies within ENTSO-E or PLEF, or from national adequacy and electricity generation reports. More information on these European and regional studies can be found in section 1.7.

The report's main hypotheses are cited for the countries that have a strong impact on Belgium regarding adequacy, namely France, the Netherlands, Germany, Great Britain and Luxembourg.

4.1 FRANCE

2 scenarios of thermal generation facilities based on RTE's recent report ('high' and 'low') due to:
– risk of coal closure (possible 'carbon tax')
– risk of additional closures if no capacity remuneration mechanism

In both thermal scenarios, France is adequate after 2020. Based on recent information the 'high' scenario (not known when constructing the assumptions) is the most likely for winter 2017-18 although the 'base case' of this study is based on a scenario in between the 'high' and 'low' scenario.

High nuclear unavailability is currently observed before and possibly during the winter 2016-17. The impact of a similar event on Belgian adequacy for the winter 2017-18 is evaluated with a sensitivity test removing 9 nuclear units from the system.

The French assumptions used in this study are based on the most recent adequacy report ('bilan prévisionnel') issued by the French transmission system operator (RTE) that was published in July 2016 [20]. RTE uses the same probabilistic method as well as the same model to simulate the European market. All data that are mentioned in this section can be found back in the French report for adequacy. The RTE report covers winters 2016-17 until 2020-21 inclusive.

4.1.1 ELECTRICITY SUPPLY IN FRANCE

TREND IN THERMAL CAPACITY (EXCLUDING NUCLEAR):

Given the uncertainty identified by RTE about the 'carbon tax' and the capacity remuneration mechanism (CRM) currently under discussion in France, two thermal scenarios were created by the TSO based on producer's information. Those two scenarios are willingly contrasted.

Two RTE scenarios for the three next winters:

- **'high' scenario:**

– all CCGT units are considered in the market;
– coal units are considered in the market;
– decentralised thermal production considered in the market.

- **'low' scenario:**

– decommissioning or mothballing of 3 GW of CCGT are considered;
– decommissioning of the total coal capacity;
– decommissioning of 1 GW decentralised thermal production.

In order to have a 'base case' trajectory in the strategic volume calculations for winter 2017-18, a scenario in between the two RTE scenarios was created based on the status on 15 October 2016:

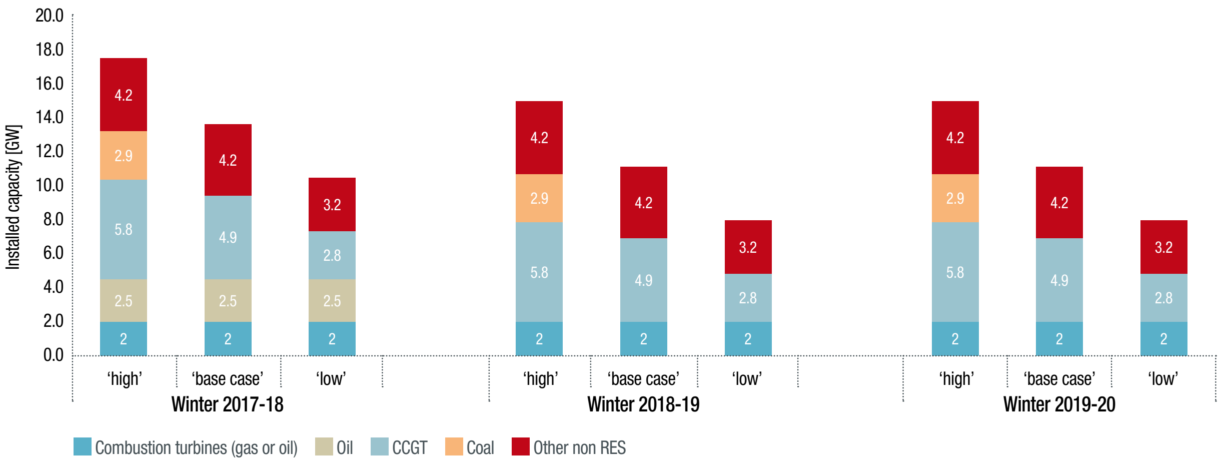
- **'base case' scenario used in this study for the three next winters:**

– decommissioning of total coal capacity (2.9 GW) following the carbon tax;
– decommissioning of two CCGT units (0.9 GW).

The 'base case' scenario was chosen on 15 October 2016. Recent information on the **'carbon tax' in France** indicates that it will be abandoned by the government [29]. The assumption about removing coal capacity (2.9 GW) can therefore be seen as conservative.

The three scenarios involving thermal generation (excluding nuclear) are shown in Figure 76 below. There is a difference of around 7 GW of installed capacity between the 'high' and 'low' scenarios.

INSTALLED CAPACITY CONSIDERED FOR THE 'BASE CASE', 'LOW' AND 'HIGH' SENSITIVITIES FOR THE FRENCH GENERATION FACILITIES (EXCLUDING NUCLEAR) (FIG. 76)



Given the uncertainties regarding French thermal generation facilities (excluding nuclear), two sensitivities have been analysed in this study. The 'base case' already considers a scenario in between the 'low' and 'high' scenario from RTE adequacy report.

– the **'high'** scenario considers the ful availability of coal, CCGT and other non-RES capacity;

– the **'base case'** scenario considers the decommissioning of the coal capacity (2.9 GW) and 2 CCGT units (0.9 GW). This is 3.8 GW lower than the 'high' scenario;

– the **'low'** scenario: additional decommissioning of CCGT units (2.1 GW) and 1 GW of other non RES capacity.

It is important to note that recent information show that the coal capacity will most probably stay in the market. The 'base case' can be seen as conservative in this regard.

TREND IN THE NUCLEAR INSTALLED CAPACITY

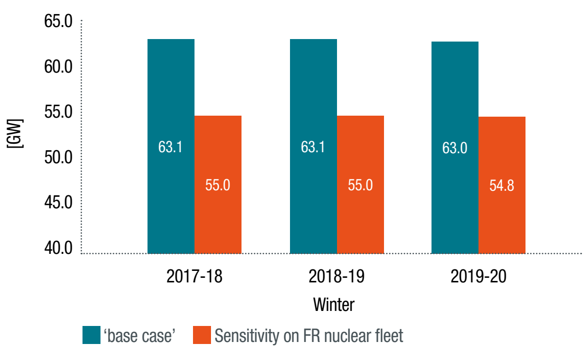
There are 63.1 GW of nuclear installed capacity in France, divided across 19 sites around the country. The installed capacity in the 'base case' is considered stable over the next three winters. The new EPR[31] reactor in Flamanville should be available for winter 2019-20 and the oldest nuclear site (Fessenheim 1&2) should be decommissioned at the same time. This will lead to a small 200 MW decrease in installed capacity from that time on.

For future years, there is a major uncertainty regarding the installed capacity of nuclear units given the French 'Energy Transition' legislation, the goal of which is to decrease nuclear electricity production by 50% by 2025. Moreover, as most of the nuclear units were built in the 1980's and 1990's, they will reach 40 years of age in five years. The French Nuclear Safety Agency (ASN) will perform indepth examinations of the installations and decide on lifetime extension, although this will only affect the installed capacity after the time-frame under study.

Given the high unavailability rate observed before and during winter 2016-17 (see box for more information), a sensitivity capturing this has been simulated.

Figure 77 summarises the installed nuclear capacity taken into account in the 'base case' and sensitivity.

INSTALLED NUCLEAR CAPACITY CONSIDERED IN FRANCE FOR THE 'BASE CASE' AND FOR THE SENSITIVITY ON THE FRENCH NUCLEAR FLEET (FIG. 77)



A sensitivity was studied with regards to French nuclear availability by removing nine nuclear units from the generation facilities (in addition to usual maintenance and forced outages). See section 6.2.3.3 for more information about this analysis.

31. EPR: European Pressurised Reactor (third generation nuclear reactor).

HIGH LEVEL OF MAINTENANCE FOR NUCLEAR FACILITIES FOR WINTER 2016-17

Nuclear maintenance is planned for several reasons, including refuelling of the units or heavy maintenance works. Given the very large number of nuclear power plants in France, such work is scheduled throughout the year in order to maximise the availability of those units during the most critical periods of the winter. In addition to planned maintenances, a unit can be stopped due to an unexpected event such as a forced outage or at the request of the Nuclear Safety Agency (ASN) for inspections (which is currently the case for winter 2016-17).

Based on ten years of historical data such, as shown in the French adequacy report (page 62, figure 3.18), the total unavailable nuclear capacity in France (including forced and planned outages) is between:

- 7 GW and 22 GW in November
- 1 GW and 13 GW in December
- 3 GW and 8 GW in January
- 3 GW and 13 GW in February
- 8 GW and 15 GW in March

Maintenance and the forced outage of units based on historical data are taken into account in the simulation tool and are therefore captured in the results.

Given the high maintenance rate of French nuclear units and ongoing inspections by the ASN due to several reasons, the availability of those power plants is expected to be very low for winter 2016-17.

Taking into account the latest information when finalising this report in early November 2016, the following situation could impact the adequacy of France in the event of a cold spell:

- four nuclear units are closed for long term maintenance for different reasons for the whole winter 2016-17;
- five units are scheduled for inspection until almost the end of 2016 at the request of the ASN. The restart dates could be further postponed as the ASN has already done several times;
- four units are scheduled for inspections from the beginning of the winter holidays until mid-January 2017.

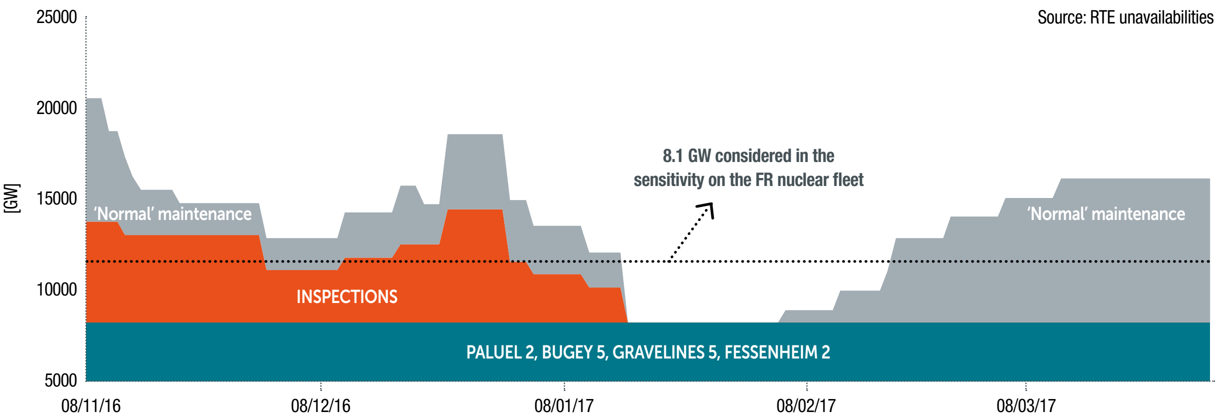
In addition to these events, 'normal' maintenance for nuclear units is scheduled as is the case every year.

If the calendar dates known in early November 2016 do not change, this would result in around 8 GW out of operation until the end of 2016, 8 GW until mid-January, and 4 GW from mid-January on.

According to this information, sensitivity to French nuclear availability has been performed by removing nine nuclear units in France for the whole winter and keeping usual maintenance rates and forced outages for the rest of the nuclear fleet.

The status on 7 November 2016 is given in Figure 78 based on the latest information from RTE's unavailability website (publically available information [30]). The chosen amount of nuclear capacity being considered in the sensitivity to French nuclear generation facilities is also shown. This can be seen as representative for the situation that is foreseen until mid-January 2017.

WINTER 2016-17 FRENCH NUCLEAR POWER PLANTS IN MAINTENANCE OR FOR INSPECTIONS (STATUS: 07/11/2016) (FIG. 78)



The latest information on the unavailability of French units can be found on RTE's website [30].
More information on the four nuclear reactors out for winter 2016-17:
- Paluel 2 [31]
- Bugey 5 [32]
- Gravelines 5 [33]
- Fessenheim 2 [34]

More information on ASN's ongoing inspections of the nuclear fleet (press articles) [35] [36] [37] [38] [39] and ASN's website: [41].

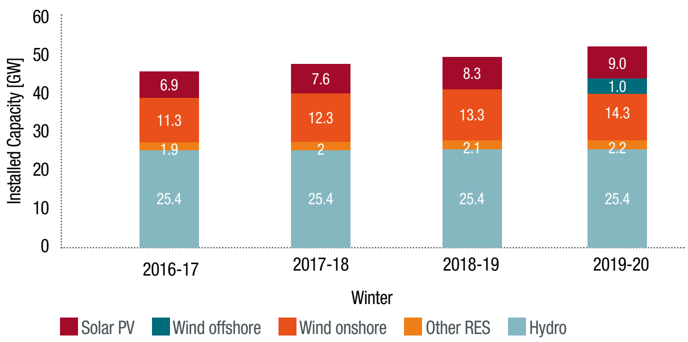
EVOLUTION OF THE RENEWABLE ENERGY SOURCES

France has a high volume of hydro installed capacity, mainly from big reservoirs in the mountains and run-of-river installations. Pumped-storage units' turbining capacity is also included in the hydro installed capacity in Figure 79.

The expected trend in renewables is as follows:

- + 1GW/year for onshore wind;
- + 700 MW/year for PV installations;
- + 100MW/year for biomass units;
- offshore wind is expected for 2020.

INSTALLED RES AND PUMPED STORAGE CAPACITY IN FRANCE CONSIDERED FOR THE 'BASE CASE' IN THIS STUDY (FIG. 79)

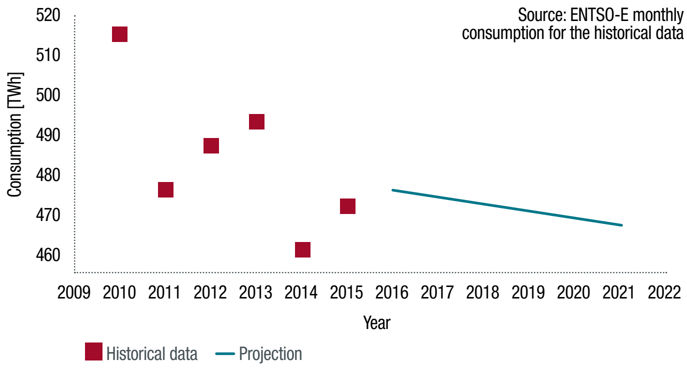


4.1.2 ELECTRICITY DEMAND IN FRANCE

TREND IN DEMAND

RTE's 'reference' scenario was taken for the 'base case' used in this analysis. This scenario forecasts a decrease in total electricity demand in France for the next year. This is mainly due to energy efficiency compensating for increased consumption due to new uses for electricity and GDP growth. The historical total demand data are shown in Figure 80. Historical consumption is not normalised for temperature. Meteorological fluctuations are therefore also included. The projected normalised consumption is shown on the figure as well. A decrease of around 8 TWh is forecast from 2016 to 2021. Following the same trend, French peak demand is also expected to decrease slightly.

DEMAND EVOLUTION IN FRANCE (FIG. 80)



The thermosensitivity of consumption in France is very high. It accounts for around 2400 MW/°C. This means that if the average temperature in France falls by 1 °C, electricity consumption increases by 2.4 GW. This is mainly due to the high penetration of electrical heating in the country [50] [51] [52].

MARKET RESPONSE

Market response which is mainly related to demand side management, accounts for around 3.2 GW and is taken into account in this study.

4.1.3 ADEQUACY RESULTS FOR FRANCE BASED ON RTE'S ADEQUACY REPORT

The French adequacy report shows results for France in the interconnected case (see Figure 81). The two scenarios presented by RTE show different situations given the difference in installed capacity between the two. In the 'high' scenario, the country is adequate with a comfortable margin for the next three winters. In the 'low' scenario, adequacy problems arise from winter 2018 and onwards. Note that from winter 2020-21, in both scenarios the country is adequate (this is due to additional commissioned CCGT, new interconnections with Italy and Great Britain and new wind offshore capacity).

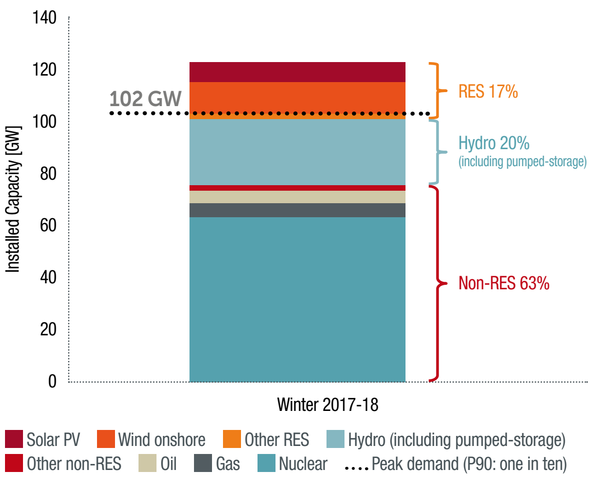
LOLE AND DEFICIT/MARGIN FOR FRANCE FOR THE 2 SCENARIOS CALCULATED BY RTE (FIG. 81)

RTE scenarios and results		2016-17	2017-18	2018-19	2019-20	2020-21
'high' scenario	LOLE	0h45	0h30	1h00	0h45	0h15
	Margin (+) or deficit (-)	4700 MW	5400 MW	3600 MW	3700 MW	6600 MW
'low' scenario	LOLE	2h30	3h45	6h45	6h15	2h15
	Margin (+) or deficit (-)	600 MW	-700 MW	-2500 MW	-2400 MW	900 MW

Source: RTE 'bilan prévisionnel' results

Figure 82 gives an overview of installed capacity in France for winter 2017-18 in the 'base case'. P90 peak demand is also indicated in the chart.

INSTALLED CAPACITY CONSIDERED IN THE 'BASE CASE' AND PEAK DEMAND FOR WINTER 2017-18 IN FRANCE (FIG. 82)



4.2 THE NETHERLANDS

Latest adequacy report by TenneT indicates that, for 2017, the Netherlands can ensure their adequacy solely by relying on domestic power production.

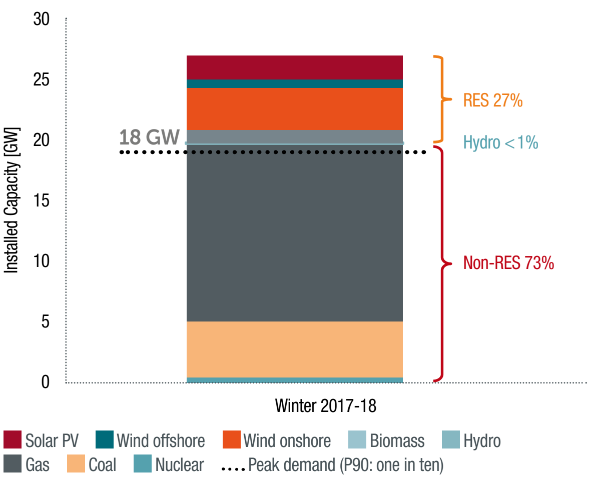
Taking into account the expected reduction in operational thermal production capacity, the TenneT adequacy study shows that, by 2020, the Netherlands might have to rely on imports for their security of supply.

The Dutch national adequacy study analyses a scenario in which a further reduction of operational thermal production capacity would occur. In the current analysis, this is studied in a sensitivity.

The assumptions used in this study for the Netherlands, collected through bilateral contacts with Dutch TSO TenneT, are in line with those used for the Dutch national adequacy study, *Rapport Monitoring Leveringszekerheid 2016* [74]. The 'base case' scenario from that study is used in the current analysis.

Figure 83 gives the assumptions used for Dutch electricity supply and demand for winter 2017-18. Sections 4.2.1 and 4.2.2 elaborate on, respectively, supply and demand in the Netherlands. The Dutch national adequacy study, released in October 2016, is discussed along with its main results in section 4.2.3.

INSTALLED CAPACITY CONSIDERED IN THE 'BASE CASE' AND PEAK DEMAND FOR WINTER 2017-18 IN THE NETHERLANDS (FIG. 83)



4.2.1 ELECTRICITY SUPPLY IN THE NETHERLANDS

NON-RENEWABLE ELECTRICITY PRODUCTION

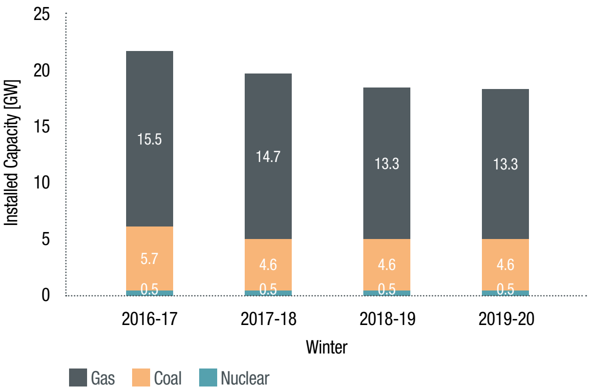
Non-renewable electricity production in the Netherlands is mainly fuelled by **gas and coal**; see Figure 84 for the assumptions used in this study. In 2014 and 2015, new coal power plants became operational for a total additional installed capacity of approximately 3.4 GW. However, sustainable energy policies have resulted in the closure of three older coal power stations for a total of 1.6 GW in 2016. Furthermore, in 2017, it is expected that another 1.1 GW of older coal power plants will be taken out of operation.

As in other European countries, Dutch gas-fired power plants are facing difficult economic conditions. Therefore, in 2015 a total of 4.3 GW of gas-fired production units have been temporarily taken out of operation ('mothballed'). It is assumed that in the coming years even more units will stop operations due to the difficult economic conditions. This results in a total installed mothballed capacity of 4.7 GW for winter 2017-18 and 6 GW for winter 2018-19. This study uses the conservative assumption that none of the mothballed power plants will resume operation.

A sensitivity was analysed in which, in addition to what was discussed above, 1.5 GW of non-renewable thermal production will be taken out of service, either temporarily or definitively. This sensitivity, which is comparable to the 'variant B' scenario set out of the Dutch national adequacy report, is discussed further in section 6.2.4.

The Borssele **nuclear** power plant (installed capacity of approximately 0.5 GW) is the Netherlands' only nuclear generation facility, and is considered operational for the complete length of this study. For the time-frame of this study, no new Dutch nuclear power plant projects are being considered.

INSTALLED NON-RENEWABLE PRODUCTION IN THE NETHERLANDS CONSIDERED FOR THE 'BASE CASE' IN THIS STUDY (FIG. 84)



A sensitivity has been analysed on the installed capacity of Dutch thermal production capacity, by considering an additional 1.5 GW of non-renewable thermal production out of service. This sensitivity is comparable to the 'variant B' scenario set out in the Dutch adequacy study. See section 6.2.4 for more information concerning this analysis.

ENGIE TAKES HALF OF ITS GAS-FIRED POWER PLANTS OUT OF OPERATION – SOURCE : HET FINANCIEELE DAGBLAD 5 OCTOBER 2016 (TRANSLATED)

Utility company Engie is permanently closing two of the five units at the Eemscentrale gas-fired power plant. In addition, by late 2017 or early 2018, two additional power plants will be mothballed, one of which is located in Lelystad. In total this involves more than half of the gas-fired power plants owned by Engie in the Netherlands, the company reported on Tuesday. [...]

The difficult market conditions are also problematic for other electricity producers in the Netherlands. Many of Dutch gas-fired power plants have already been mothballed. Matthias Hartung, chairman of the board of RWE, told the German media in late September that those power plants will remain unprofitable for quite some time, despite the slightly improving market conditions.

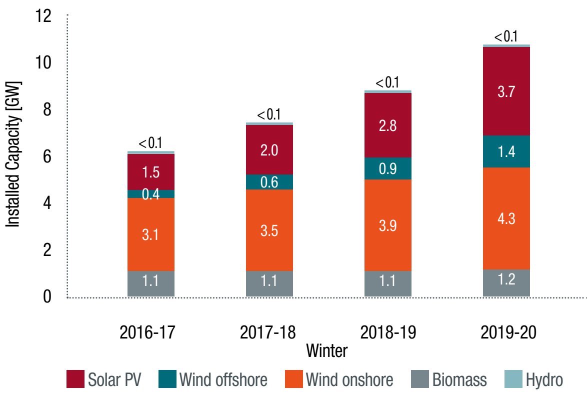
[...]

RENEWABLE ELECTRICITY PRODUCTION

The Dutch national adequacy study bases its forecasts for installed capacity of **renewable** electricity production on the report entitled *Nationale energieverkenning 2015* (NEV) [75], a study conducted by the Netherlands Energy Research Centre (ECN). The 'observed policies' scenario set out in this study was used to develop the assumptions. The NEV-study takes into account the agreement concluded in 2013 between the Dutch government and non-governmental organisations on sustainable energy (*Energieakkoord voor duurzame groei* [76]). In the agreement, a target of 14% renewable energy in total gross energy use is envisioned. However, the 'observed policies' in the NEV-study assumes 10% to 12% renewable energy in total gross energy use for 2020.

The assumptions used in this study concerning the installed capacity renewables are shown in Figure 85. In total, the installed capacity of RES is expected to almost double over the next four years. Very high growth is expected in PV (installed capacity up 142%) and offshore wind (installed capacity up 292%) segments. According to the NEV-study, the increase should allow the Netherlands to reach a proportion of 10% to 12% of renewable energy in its energy mix.

INSTALLED RES AND PUMPED STORAGE CAPACITY IN THE NETHERLANDS CONSIDERED FOR THE 'BASE CASE' IN THIS STUDY (FIG. 85)

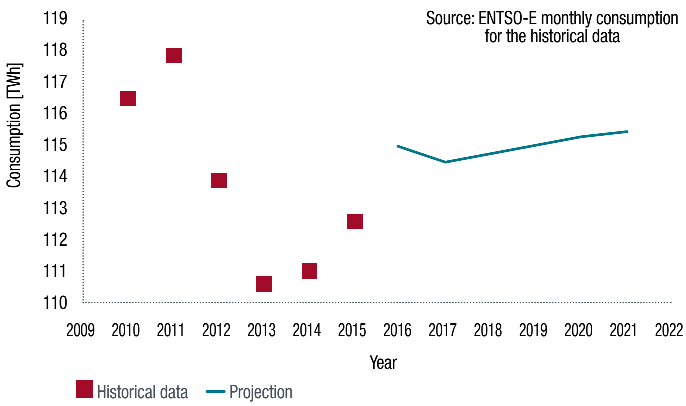


4.2.2 ELECTRICITY DEMAND IN THE NETHERLANDS

The assumptions with regard to electricity demand in the Netherlands are also in line with the Dutch adequacy report. In turn, this study takes as its basis the projected demand growth of the aforementioned NEV-study ('observed policies' scenario). Figure 86 shows the historical Dutch electricity demand (not normalised for temperature), as well as the projection (normalised for temperature) for the coming years. After a limited decrease between 2016 and 2017, the electricity demand is expected to exhibit a slight increase for the period under study.

This study does not take into account any **demand side response** potential in the Netherlands. This is a conservative assumption, in the absence of better information concerning this topic. Electricity demand is less sensitive to temperature as in most other European countries. In this study, a temperature sensitivity of 90 MW/°C is assumed [57].

DEMAND EVOLUTION IN THE NETHERLANDS (FIG. 86)



4.2.3 DUTCH NATIONAL ADEQUACY STUDY

The Dutch national adequacy study, *Rapport Monitoring Leveringszekerheid 2015-2031*, uses a probabilistic method that does not explicitly take into account the available production capacity in other countries. Accordingly, the national adequacy is assessed taking into account **only domestic production**. Similar to this analysis, a LOLE value and capacity margin or deficit is calculated. A possible deficit resulting from the analysis can then be compared to the interconnection capacity the Netherlands has with its neighbouring countries. However, since this analysis only takes domestic production into account, the LOLE and margin/deficit resulting from the Dutch adequacy study should not be directly compared to those calculated in the context the current study. As already mentioned in section 1.3, the Dutch adequacy criterion is a LOLE less than 4 hours.

In Figure 87, the results from the Dutch adequacy study are shown for the 'base case' scenario and the 'variant B' scenario, which assumes further decommissioning of thermal power plants. For the 'base case', the 2500 MW margin in 2016 evolves into a 500 MW deficit in 2020. This deficit does not mean that there is a problem of scarcity for 2020; it merely indicates that **the Netherlands will have to rely on imports** to assure its adequacy by 2020. The significant increase in RES production does not compensate for the reduction in operational thermal capacity, mainly because of the intermittent nature of RES production. The results shown in Figure 87 also show that a further reduction in operational thermal production capacity, as in the 'variant B' scenario, increases the need for imports to the Netherlands.

LOLE* AND DEFICIT/MARGIN FOR THE NETHERLANDS FOR THE TWO SCENARIOS CALCULATED BY TENNET (FIG. 87)

TenneT adequacy results for two scenarios		2016	2017	2020	2023
'base case'	LOLE*	0h00	0h04	11h09	28h15
	Margin (+) or deficit (-)	2500 MW	1300 MW	-500 MW	-1000 MW
Variant B	LOLE*	0h02	3h32	342h01	415h35
	Margin (+) or deficit (-)	1600 MW	0 MW	-2600 MW	-3000 MW

Source: TenneT *'Rapport Monitoring Leveringszekerheid 2015-2031'* results

* The LOLE values are calculated without considering power available in other countries, and can therefore not be interpreted in the same way as LOLE values calculated in this report.

4.3 GERMANY

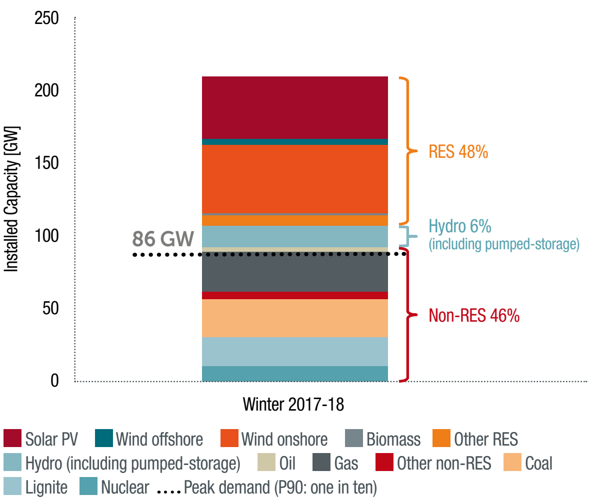
Germany has a high RES penetration but also high installed capacity of coal and lignite production. A decrease in installed capacity of coal & lignite production of approximately 6 GW is expected towards 2020.

A grid reserve ('Netzreserve') is contracted to ensure grid stability.
A capacity reserve (out of the market) up to 4.4 GW can be contracted to ensure security of supply of the country.
The so called 'climate reserve' of 2.7GW of old and inefficient coal and lignite units in standby can be called upon last resort.

Germany has a confortable margin when scarcity occurs in Belgium and France because of its large amount of possible imports from the north & the east, and its diversified domestic generation facilities.

The assumptions 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 data from the German Ministry of Energy [56]. Figure 88 summarises the assumptions on supply and demand for winter 2017-18. Germany's electricity supply and demand are discussed more in detail in section 4.3.1 and section 4.3.2, respectively. Finally, section 4.3.3 elaborates on the security of supply in Germany, and the specific measures taken to ensure it for the coming years.

INSTALLED CAPACITY CONSIDERED IN THE 'BASE CASE' AND PEAK DEMAND FOR WINTER 2017-18 IN GERMANY (FIG. 88)



4.3.1 ELECTRICITY SUPPLY IN GERMANY

NON-RENEWABLE ELECTRICITY GENERATION

The assumptions used for non-renewable electricity generation in Germany are shown in Figure 89. It can be observed that total installed capacity of non-renewable electricity production is expected to drop by approximately 7% over the coming four winters.

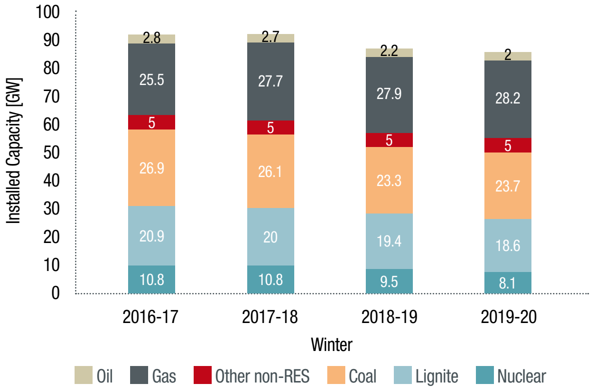
In 2010, the German government passed the *Energiewende* legislation. One of the key points in this energy transition policy is the phase-out of all German **nuclear** power production by 2022. Of the 17 nuclear reactors in operation at the end of 2010, eight have already been taken out of operation. It is expected that two more nuclear power plants will be shut down over the course of next three winters [83].

Over the last five years, almost half of nuclear installed capacity has been taken out of operation. This amounts to a reduction in installed nuclear power production of almost 10 GW.

In 2015, almost 42% of the electricity generated in Germany was generated from **coal and lignite** [85]. A significant reduction in installed capacity based on German coal and lignite production is expected. This is, in part, in line with environmental policies, as well as government plans to phase out hard coal mining subsidies.

Although a number of **gas-fired** power plants are expected to end operations, a slight increase in gas-fired power production is forecast. Several new efficient CCGT plants are expected to begin operations in the coming years.

INSTALLED NON-RENEWABLE PRODUCTION IN GERMANY CONSIDERED FOR THE 'BASE CASE' IN THIS STUDY (FIG. 89)

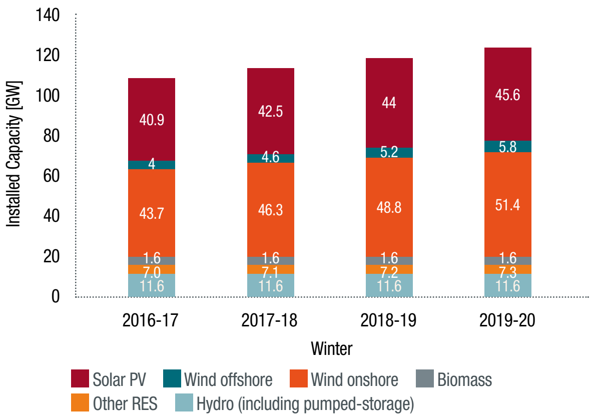


TREND IN RENEWABLE CAPACITY IN GERMANY

Figure 90 shows the hypotheses used for the installed capacity of German renewable electricity production. In 2015, approximately 30% of German electricity production originated from renewable sources, up 4% from 2014 [86]. This large proportion of electricity generation from renewable sources is due to the high volume of wind and solar capacity, accounting for installed capacity of almost 90 GW. Taking into account biomass, hydro and other renewables, the installed capacity of renewable electricity production exceeds 100 GW.

This study takes into account an average annual growth of 2.5 GW for onshore wind production, and 1.5 GW for photovoltaic production. An increase in offshore wind capacity is also forecast to reach around 6 GW in winter 2019-20. Other renewables are assumed to stay stable over the period under study. Hydro run-of-river units for about 4 GW are installed in Germany. In addition, Germany has around 9 GW of production capacity from pumped-storage facilities.

INSTALLED RES AND PUMPED STORAGE CAPACITY IN GERMANY CONSIDERED FOR THE 'BASE CASE' IN THIS STUDY (FIG. 90)

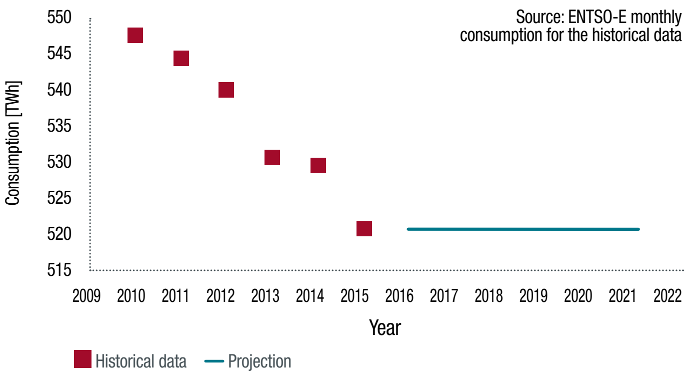


4.3.2 ELECTRICITY DEMAND IN GERMANY

Over the past six years, an average annual decrease of approximately 1% has been observed in Germany's total electricity demand (not normalised). This trend, as well as the assumption used in this study for the German demand is given in Figure 91. Although it seems reasonable that this downward trend could continue, in this study, no trend is assumed for the normalised demand for the winters under study. This hypothesis is chosen out of prudence, so as not to underestimate the German load.

For this study, it is assumed that the temperature sensitivity of German total demand is 500 MW/°C [53]. In the absence of good information on this, no demand side response is taken into account in the modelling.

DEMAND EVOLUTION IN GERMANY AND FORECAST (FIG. 91)



4.3.3 SECURITY OF SUPPLY IN GERMANY

In 2016, new legislation was passed in Germany confirming that the current **grid reserve** (*Netzreserve*) needed to cope with bottlenecks and ensure grid stability will be extended beyond 2017 (for winter 2016-17 this reserve amounts to 5.4 GW) [84].

An **additional capacity reserve** will be put in place (which will be out of market and used only when all the market-based options have already been used). This reserve could have a total capacity of 4.4 GW if needed. In the first stage, technology-neutral tenders will be organised to contract 1.8 GW from 2017 until 2019. The government has explicitly stated that it would not interfere in the power market if prices rise, thus hoping to create a more stable investment climate for electricity producers

The so-called **'climate reserve'** will have a capacity of 2.7 GW and will comprise old and inefficient lignite and coal power plants. This measure will make it possible to reduce CO_2 emissions by only deploying those units as a last resort. Those units are put on standby for four years and will then be closed permanently [88].

RWE, VATTENFALL LIGNITE PLANTS TO ENTER $1.8 BILLION RESERVE – Source: Bloomberg 24/10/2015

Germany forged an accord with three utilities to relegate some of their dirtiest power plants to the nation's reserve generating capacity to help cut carbon pollution and avert blackouts.

Over seven years from the winter of 2016, eight lignite power plants owned by RWE AG, Vattenfall AB and Mitteldeutsche Braunkohlegesellschaft mbH will be placed in stages in the reserve to create a 2.7 GW backstop, the Economy and Energy Ministry said Saturday. The utilities will be paid about 1.6 billion euros ($1.76 billion) in all to keep the plants offline except in an emergency when power demand exceeds supply, it said. The ministry didn't name the plants.

Chancellor Angela Merkel's government has said it has a threefold aim in keeping some of German energy generation's biggest polluters offline without shutting them down: cutting carbon emissions to meet its climate pledges, setting up a backstop against outages as clean energy expands and finally to assuage utilities that might otherwise shut down plants and fire workers. [...]

4.4 GREAT BRITAIN

Security of supply in Great Britain is managed through the Capacity Market (CM). Two CM auctions have now been held, for delivery in 2018-19 and 2019-20 respectively. In January 2017, an auction will be held for delivery during the winter 2017-18.

For the winter 2016-17, National Grid contracted 3.5 GW (de-rated) of Supplemental Balancing Reserves (SBR). The SBR mechanism supports the transition towards the CM, and no more SBR will be contracted as of the winter 2017-18.

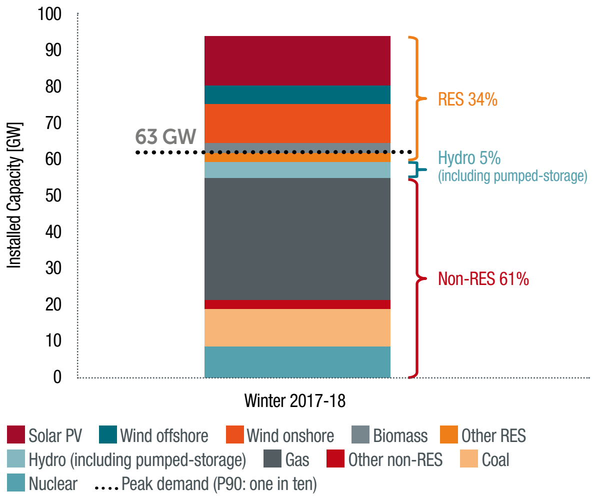
A reduction of the installed thermal capacity is foreseen, in part resulting from the introduction of a Carbon Price Floor (CPF) in 2013.

This section elaborates on the assumptions used in this study for Great Britain. In general, these assumptions are in line with the 2016 edition of the Future Energy Scenarios (FES) [27], supplemented with information published by the British government [79]. The FES is a report published by the British TSO National Grid, describing a set of scenarios up to 2050. From the FES report, the assumptions of the 'Slow Progression' scenario are used in this analysis. The differences in terms of installed capacity and demand between the scenarios detailed in the FES report are limited on the short term.

In the 2013 Energy Act [77], the British government introduced the **Electricity Market Reform (EMR)**. Two policies resulting from the EMR are the introduction of a Capacity Market (CM) and the Contracts for Difference (CfD) mechanism. The British CM is to ensure security of supply in Great Britain, and is further elaborated on in section 4.4.3 regarding the general security of supply in Great Britain. The CfD mechanism gives incentives to low-carbon electricity generation capacity.

Section 4.4.1 elaborates on the assumptions used for electricity supply in Great Britain. Section 4.4.2 details the demand hypotheses used in the current analysis. Figure 92 summarises the supply and demand hypotheses for Great Britain for winter 2017-18.

INSTALLED CAPACITY CONSIDERED IN THE 'BASE CASE' AND PEAK DEMAND FOR WINTER 2017-18 IN GREAT BRITAIN (FIG. 92)



4.4.1 ELECTRICITY SUPPLY IN GREAT BRITAIN

NON-RENEWABLE ELECTRICITY GENERATION

Historically, in Great Britain electricity generation has mainly been fuelled by gas and coal. However, in 2013, the British government introduced a Carbon Price Floor (CPF). Initially, this mechanism aimed to induce a carbon price of £30/tCO_2 by 2020[32], but it was modified in 2016 to limit its impact on British competitiveness [78].

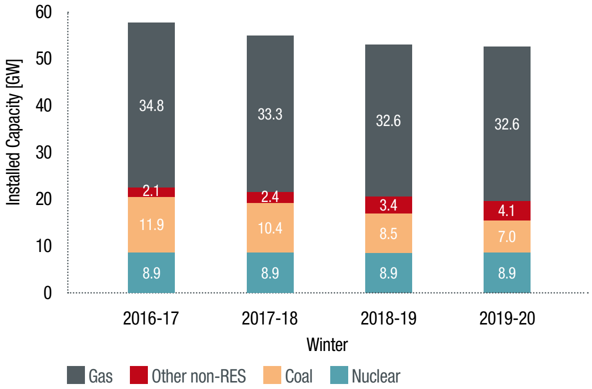
Figure 93 shows the hypotheses used for Great Britain concerning non-renewable thermal production. The CPF puts significant pressure on the profitability of **coal-fired** plants. This has resulted in a decrease in installed of capacity coal-fired production of about 5.4 GW in 2016 compared to its 2015 level of 17.3 GW. It is expected that the installed capacity of coal-fired electricity production will continue to drop from 10.4 GW for winter 2017-18 to 7.0 GW for winter 2019-20. In total, this amounts to a nearly 60% decrease in installed coal-fired capacity over four winters.

32. A carbon price of £30/tCO_2 by 2020 in 2009 prices was initially envisioned.

British **gas-fired** production units are not expected to face the same profitability issues as in the rest of Europe. A small decrease of approximately 2 GW from the 2016 levels is expected, but is largely offset by additional CHP projects and other non-renewable small generation. No closures of existing **nuclear** units are taken into account, and the most advanced new nuclear project – the EPR Hinkley Point C – will not be operational in the years under study.

> The installed capacity of coal-fired plants is expected to decrease by almost 60% over four winters in Great Britain.

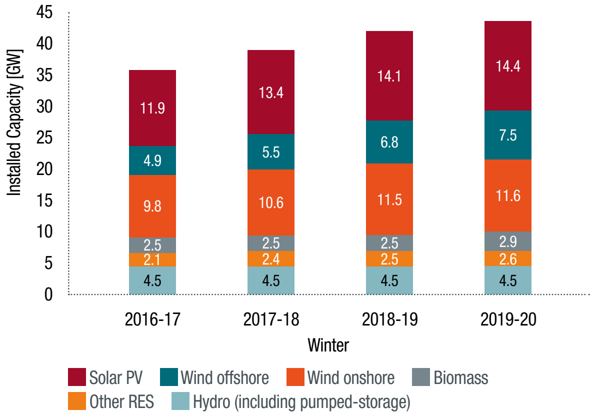
INSTALLED NON-RENEWABLE PRODUCTION IN GREAT BRITAIN CONSIDERED FOR THE 'BASE CASE' IN THIS STUDY (FIG. 93)



RENEWABLE ELECTRICITY GENERATION

Figure 94 shows the assumptions used in this study for renewable electricity generation in Great Britain. The development of renewable electricity generation capacity in Great Britain is incentivised through the Contracts for Difference (CfD) mechanism, introduced in the 2013 Electricity Market Reform. The installed capacity of offshore wind is expected to more than double for winter 2019-20 compared to winter 2016-17. For photovoltaic and onshore wind production, an increase of approximately 20% in installed capacity is expected for the same period. No significant trend is forecast during the period under study for biomass, hydro and other renewable production capacity.

INSTALLED RES AND PUMPED-STORAGE CAPACITY IN GREAT BRITAIN CONSIDERED FOR THE 'BASE CASE' IN THIS STUDY (FIG. 94)

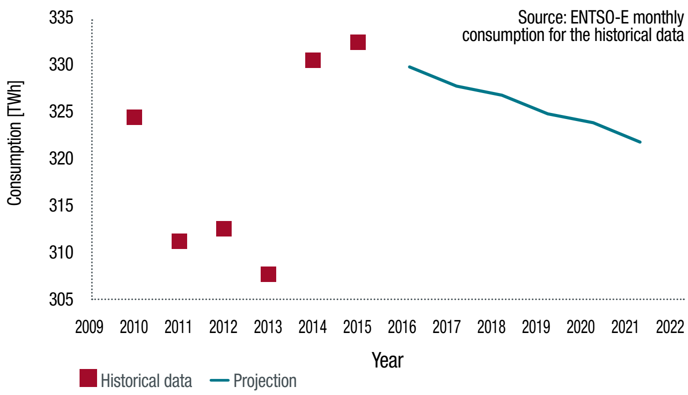


4.4.2 ELECTRICITY DEMAND IN GREAT BRITAIN

The total electricity demand assumption used in this study for Great Britain is in line with the 'Slow Progression' scenario found in the 2016 FES report. As for all 2016 FES scenarios, this scenario foresees a reduction in the normalised annual electricity demand up to and including 2020. In the case of the 'Slow Progression' scenario, this demand reduction amounts to approximately 0.6% per year between 2015 and 2020.

Figure 95 shows historical electricity demand in Great Britain (not normalised for temperature) together with the projection used in the current study (normalised for temperature). No demand side response is taken into account for Great Britain, in the absence of sufficiently good information on this topic. For this study, the sensitivity of electricity demand in Great Britain to temperature is assumed to be 800 MW /°C [52].

DEMAND EVOLUTION IN GREAT BRITAIN (FIG. 95)



4.4.3 SECURITY OF SUPPLY IN GREAT BRITAIN

The latest report analysing security of supply in Great Britain for a medium term horizon is the *Electricity Capacity Report 2016* [80], submitted in May 2016 to the British government by National Grid. In this report, a recommendation is made concerning the Capacity Market volume that should be secured for winters 2017-18, 2018-19 and 2020-21. The recommendation uses a Least Worst Regret (LWR) methodology that takes into account multiple scenarios (all FES scenarios and one additional scenario) and sensitivities. Subsequently, it is up to the government to decide on the details of the Capacity Market auction.

According to the calculations made by National Grid for its Electricity Capacity Report 2016, if the recommended volume are contracted, Great Britain will be able to meet its adequacy criterion of a LOLE less than or equal to three hours. For the auction for delivery in winter 2017-18, the British government followed the recommendation made by National Grid concerning the Capacity Market volume to be contracted [81]. This auction will be held in January 2017.

For winter 2016-2017, as a transitional measure, National Grid has contracted Supplemental Balancing Reserves (SBR) to ensure security of supply in Great Britain. Estimates by National Grid show that, without the contracted volume SBR, Great Britain has a LOLE of 8.8 hours. With the contracted SBR, a LOLE of 0.5 hours is estimated [82].

BLACKOUT RISK RECEDES AS NATIONAL GRID PAYS OLD COAL PLANTS TO STAY ON STANDBY – Source: The Telegraph 14 October 2016

The risk of blackouts this winter has receded but National Grid will likely have to pay old coal plants millions of pounds to stay on standby for days at a time to ensure the lights stay on. […]

In addition, National Grid has a separate reserve of 10 old coal and gas power plants that are not operating in the market but will be paid £122m through an emergency scheme to stay open in case they are needed as a 'last resort'. […]

4.5 LUXEMBOURG

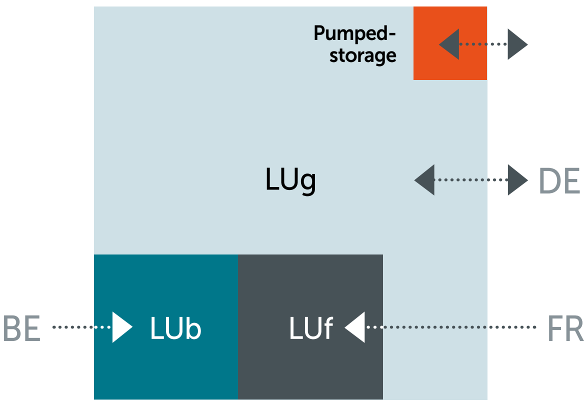
Modelling Luxembourg is important for Belgium as part of that country is connected to the Belgian control zone (this is indicated as the 'LUb' zone in Figure 96). In 2016, the CCGT located in Luxembourg but belonging to the Belgian regulation zone was closed permanently [87]. Following the closure, the 'LUb' zone includes only consumption. Consumption by that zone is therefore taken into account as part of Belgium's load. The two other electrical zones of Luxembourg are:

– a part connected to France (LUf) 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;

The 'IC BeDeLux' project is physically connecting the 'LUb' and 'LUg' zones but is not taken into account in this study. See section 5.1.6 for more information.

LUXEMBOURG MODELLING (FIG. 96)



4.6 OTHER COUNTRIES MODELLED

In total twenty countries are modelled in this study. For each country, hypotheses are made in terms of non-renewable generation facilities, demand and renewables. Most of these hypotheses are taken from pan-European adequacy studies such as the *Mid-Term Adequacy* forecast published this year and covering 2020 and 2025 (see section 1.7.3 for more information), the ENTSO-E transparency platform, ENTSO-E statistics, bilateral contacts, PLEF adequacy study, national reports and statistics.

05

INTERCONNECTION MODELLING AND ASSUMPTIONS

Elia is a pioneer in the flow-based approach for adequacy studies and has developed a methodology to model exchanges between CWE countries that replicates day-ahead operation. This method was used for the previous strategic reserve volume assessment and will be used again in this one with a major improvement: allowing the use of **more than one flow-based domain**. This will better capture uncertainties about Belgium's import and export capabilities.

Exchange capabilities between countries are modelled as is currently done on the day-ahead market:

- Commercial exchanges **inside the CWE** region are taken into account with the same **flow-based** methodology as applied today. This is further described in **section 5.1**;
- Exchanges between **other countries and the CWE zone** are modelled with **fixed exchange capacities** between them (also called NTC – Net Transfer Capacities). See **section 5.2** for more information.

Figure 97 shows the flow-based zone comprising France, the Netherlands, Germany, Luxembourg, Austria and Belgium. Commercial exchanges between these countries are defined by the flow-based domain. Exchanges between the other countries and the CWE zone and between two countries not belonging to this zone are modelled with NTC capacities.

INTERCONNECTIONS INSIDE THE CWE ZONE ARE MODELLED WITH THE CURRENT FLOW-BASED METHODOLOGY (FIG. 97)

5.1 FLOW-BASED METHODOLOGY APPLIED TO THE CWE ZONE

5.1.1 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.

In the future, reinforcements of the Belgian backbone grid and cross-border lines are planned as detailed in the Federal Network Development Plan [61]. 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.

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.

The maximum **import capacity** is the capacity that can be introduced into Belgium depending on available resources for voltage regulation, short-circuit power and inertia that are normally offered by the countries' internal production. In the event of considerable imports, steps must be taken to ensure that such production is still sufficiently present.

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).

MAXIMUM 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 is an input into the flow-based domain calculation. In practice, the maximum possible import saldo 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 winter 2017-18, given the current planned investments, past observations and knowledge, maximum import capacity via the AC grid is assumed to be 4500 MW.

The actual import saldo availability of 4500 MW 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. The flow-based modelling approach makes it possible to take this effect into account.

PLANNED INVESTMENTS WITH GERMANY AND GREAT BRITAIN

The planned HVDC interconnection with Germany (ALEGrO project [62]) is not taken into account in this study as it is scheduled to commission after the time-frame covered in this study.

On the other hand, Nemo Link®, the HVDC connection with Great Britain, is taken into account for winter 2019-20 in the 'base case' as the current date of finalisation is in 2019. This connection has an exchange capability of 1000 MW between Belgium and Great Britain.

Exchanges with Great Britain for winter 2019-20 are modelled in the simulation as an additional exchange capacity not falling within the maximum simultaneous import capacity of the AC grid. This interconnection is modelled with the NTC approach (fixed commercial capacity of 1000 MW between the two countries). The assumption takes into account this link in the same way as the other existing connections between CWE countries and Great Britain modelled in today's market functioning.

The 'base case' scenario considers the Nemo Link® interconnector in operation before winter 2019-20.
A sensitivity excluding this project will be taken into account (this could be the case if delays in construction or any other unexpected event appears).
See section 6.2.5 for more information on this analysis.

5.1.2 WHY IS FLOW-BASED METHODOLOGY USED 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.

This method allows to better 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. Using the flow-based method in this assessment makes it possible to calculate the likelihood and impact of a reduced import saldo as a result of market conditions in neighbouring countries.

COMMERCIAL EXCHANGES BETWEEN TWO COUNTRIES CAN GENERATE PHYSICAL FLOWS THROUGH OTHER BORDERS. ELECTRICITY FLOWS VIA THE PATH WITH THE LEAST IMPEDANCE

RESULTING FLOWS FROM AN ENERGY EXCHANGE BETWEEN 2 ZONES (FIG. 98)

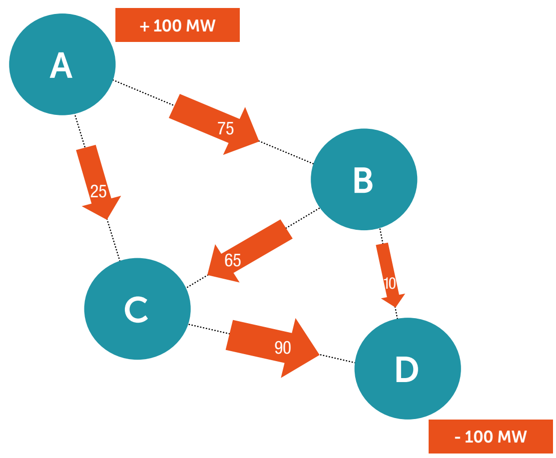


Figure 98 shows the flows between four fictitious zones when 100 MW is exchanged from zone A to zone D. The resulting flows follow the path of least impedance. This will result in flows between zones not participating in this energy exchange (zones B and C for example).

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 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 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 even more.

A didactic explanation (in French) of flow-based market coupling is available. It is based on a film produced by the French energy regulator (CRE) [64]. More information about the flow-based rules and methodologies is available from Elia [65], JAO resource center [66] and Belpex [67].

5.1.3 HOW DOES THE FLOW-BASED METHOD IN DAY-AHEAD WORK IN REALITY?

The flow-based method implemented in day-ahead market coupling uses PTDF factors that make it possible to model the real flows on the lines based on commercial exchanges between countries.

For each hour of the year, the impact of energy exchanges on each critical line (also called 'branch') is calculated taking into account the N-1 criteria (see box on N-1 criteria). This leads to many constraints. Those constraints form a safe domain of possible energy exchanges between the CWE countries (this is called the flow-based domain).

This domain is constructed based on 'critical branches' (lines or grid elements – hereafter referred as CBs), taking account of the impact of an outage on these CBs, a reliability margin 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.

Different assumptions are made for the calculation of this 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.

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.

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 maintenance or 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. However, the effect of the loss of a major grid element has been analysed as part of a sensitivity analysis (see section 6.2).

5.1.4 HOW IS THE FLOW-BASED APPROACH MODELLED IN THIS STUDY?

As part of the efforts to continuously improve adequacy calculations, Elia is one of the first TSOs to use a flow-based methodology for adequacy calculations.

In the assessment for winter 2016-17, one single representative flow-based domain was used for the entire winter. It was based on a study performed by Coreso for winter 2014-15. The chosen flow-based domain was representative for a winter situation with 'low wind' levels and cold temperatures in CWE. In order to have a better representation of possible winter situations, three different representative flow-based domains were used for this year's assessment (winter 2017-18). Such flow-based domains are then used as a fix input for all simulations ('base case' and all sensitivity analyses) except for one specific sensitivity analysis on the loss of a major grid element.

These calculated flow-based domains are based on real winter days that occurred in 2015. They are computed following exactly the same rules and assumptions applied for those historical days. Some changes explained in this paragraph were made in order to take into account future investments in the Belgian grid.

THE ADEQUACY PATCH DEFINES THE RULES WHEN SCARCITY OCCURS IN ONE OR MORE COUNTRIES

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 [45].

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

5.1.5 HOW WERE THE REPRESENTATIVE DOMAINS CHOSEN AND FOR WHICH SITUATIONS?

Within the framework of the co-development with Market Parties of a Standard Process to communicate about and Assess the Impact of significant Changes (SPAIC) within the CWE flow-based consultation group, twelve typical days for the year were defined by CWE TSOs. The representative domains are issued every six months and are based on one year of historical data. Twelve typical days for the year (four in winter, four in summer and four in inter-season) are therefore available. From those four typical days for the winter (three for the weekdays and one for the weekend), three were chosen to be used in this year assessment of the strategic reserve volume.

Each typical day consists of 24 domains (one for each hour). In order to reduce the amount of domains, hour 18 was chosen to build the future domains as this is the hour when the load is the highest and therefore the most representative for adequacy.

In order to be used in the simulations, the identified typical days were linked to climate conditions. The mapping seems to show that the wind infeed in Germany is the key parameter that drives the form of the domains for the weekdays. It was therefore decided, for this study, to use the weekday domains in function of the wind infeed in Germany.

The three typical days are explained below:

DAY 1: "LOW WIND"

This day is based on **7 November 2015**, hour 18, flow-based domain.

The production from wind during that day was between 7 and 10 GW in Germany, corresponding to around 20% of the wind installed capacity in Germany for that day.

DAY 2: "WINDY"

This day is based on **19 November 2015**, hour 18, flow-based domain.

The wind infeed (sum of onshore and offshore) in Germany of that day was for some hours above 30GW. This corresponds to around 68% of load factor for the wind (considering 44 GW of installed wind onshore and offshore capacity).

DAY 3: "WEEKEND"

This day is based on **5 December 2015**, hour 18, flow-based domain.

This was also a day with relatively high wind infeed in Germany (around 25 GW, more than half of the total installed capacity). This day was chosen for the weekend as it was the only one available for the winter from the set of typical days.

More information and charts on the historical generation and load in Germany can be found here: [91]

Note that the fourth typical day for the winter (weekday corresponding to the day 9 November 2015) is not taken into account in this study as the shape of the domain and situation is similar to the 'windy' domain.

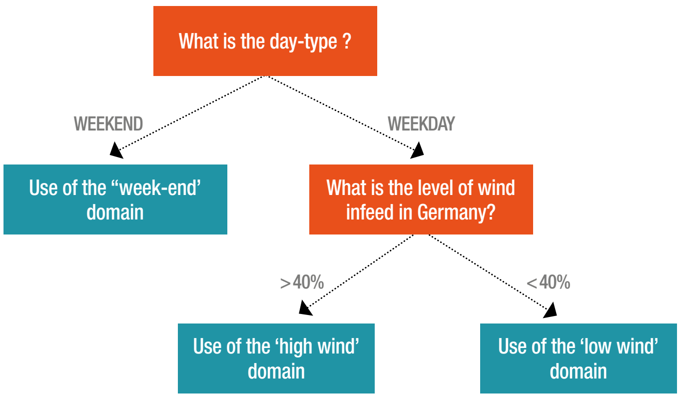
CHOICE OF THE DOMAIN WITHIN THE SIMULATION

A conservative threshold was used to choose between the 'windy domain' or the 'low wind' domain for weekdays When the wind infeed in Germany is above 40% of the total installed capacity, the 'windy domain' is used. For all the other days, the 'low wind' domain is applied.

For each day of each 'Monte Carlo' year in the simulation, depending on the wind infeed in Germany and the day type (weekend/weekday), one of the three representative flow-based domains is applied. For each climate year (there are 40 of them), the choice of the domains for each day is made again. This choice of the domain is illustrated in Figure 99.

CHOICE OF THE FLOW-BASED DOMAIN FOR SIMULATED DAY (FIG. 99)

For each day of the winter (this is repeated for each 'Monte Carlo' year):



5.1.6 WHAT CHANGES WERE MADE TO THESE HISTORICAL DOMAINS IN ORDER TO BE USED FOR FUTURE WINTERS?

The same three representative domains are used for winters 2017-18, 2018-19 and 2019-20. Changes to these historical domains were applied in order to match upcoming investments in Belgium on the 380kV grid:

- all nuclear units were set to maximum output in the historical days files that are used to construct the flow-based domains;
- line 380.26 between Doel and Zandvliet (commissioned in late October 2016, 'Brabo 1' project) was added in all the historical days;
- line 380.12 between Gramme and Van Eyck (commissioned on 22 October 2015) was added in the Day 1 'low wind' (7 January 2015) as it was not yet in operation on that day. For the other days, the line was already in operation;
- the margin given by installations for monitoring the lines ('Dynamic Line Rating: Ampacimons') was integrated where available.

Note that the flow-based domain is computed with the current operational rules and includes 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. No major outages in the Belgian grid were observed in the typical days used in this study.

NOTE ON THE 'IC BEDELUX' PROJECT:

During the trial phase the 'IC BeDeLux' project physically connect Belgium to the Luxembourg grid as of late 2016. The commercial connection between the Belgian and Austrian/Luxembourg/German market hub was postponed during the trial phase. At the physical level, there will be an interconnector (BE-LU interconnection) between Belgium and Luxembourg, with the interconnection point located at the PST situated in Schifflange. The results of the impact assessment for this interconnector concluded no commercial go-live before the termination of the trial phase which should be one year. The situation will be re-evaluated after the one year trial period. Due to the fact that the impact assessment (IA) simulations indicate that in the majority of the cases the Creos PST would not be considered in the day-ahead allocation due to the limitation of the initial flow-based domain, given the complexity of commercialising the new Creos PST in the day-ahead timeframe of which the feasibility has not been confirmed yet by all involved parties, the limited cases in which this complex process will lead to an actual offering of the Creos PST in the day-ahead timeframe and given the fact that the current IA simulations indicated that this offering would only result in a neutral effect on the CWE welfare, the project decided to postpone the commercialisation of the new Creos PST. Therefore the assumption made in the simulations is to not include this interconnector in the calculation of the flow-based domain.

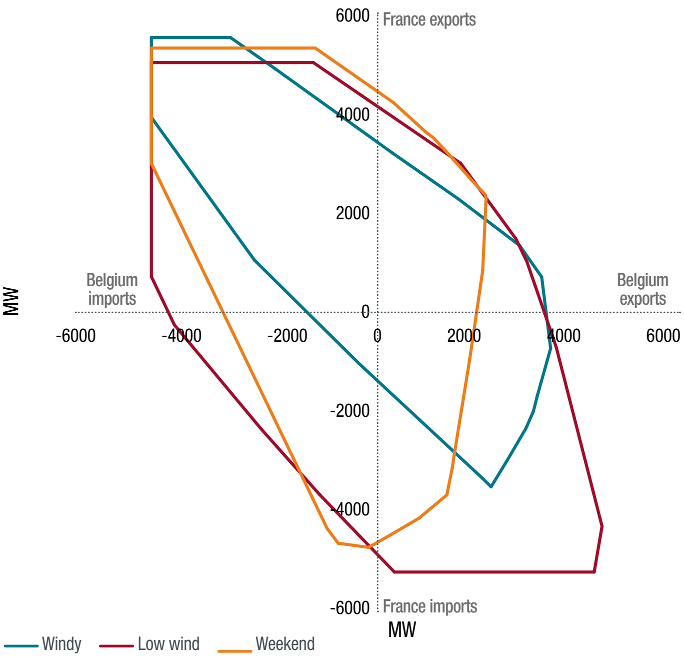
More information can be found on Elia's website [46].

5.1.7 ILLUSTRATION OF THE DOMAINS USED FOR THIS STUDY ON THE BE-FR CWE NET POSITIONS

The exchange possibilities between countries are determined by a multidimensional domain. Figure 100 shows a two-dimensional projection of the domains for two countries.

France and Belgium are currently the two countries facing the highest risk of structural shortages in the region. As a result the flow-based domain is shown on the net position of those two countries.

FLOW-BASED DOMAINS USED TO DEFINE ENERGY EXCHANGES IN THE 'BASE CASE' SCENARIO (FIG. 100)



The flow-based domain in Figure 100 only reflects the CWE net positions, so import possibilities of CWE countries outside CWE are not shown. In the model used for the volume evaluation of strategic reserves (ANTARES) as well as in the day-ahead market coupling, France can import from the other countries within the limits of the NTC constraints (e.g. if France imports 4000 MW from Italy, Switzerland, Spain and Great Britain, it is not shown on the chart of the flow-based domain as this only reflects the CWE net positions).

If there is enough production capacity in France so that it can export energy to the other countries of the CWE region, and depending on the typical day situation, Belgium can reach the assumed 4500 MW import saldo. If on the other hand France needs to import energy from the CWE zone, the possible imports for Belgium are limited and follow the border of the domain that is shown (bottom left) in the third quadrant of the graphic (moments when France and Belgium are importing). This domain border shows that the sum of the imports to Belgium and France are limited to approximately 4800 MW in the CWE zone for the 'low wind' situation. In case of 'high wind' situation, the sum that can be imported simultaneously in FR and BE from CWE is lower than 2000 MW.

5.1.8 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 reserves in the 'base case'. The impact of such a loss is assessed as a sensitivity, see section 6.2.5.2 for more details.

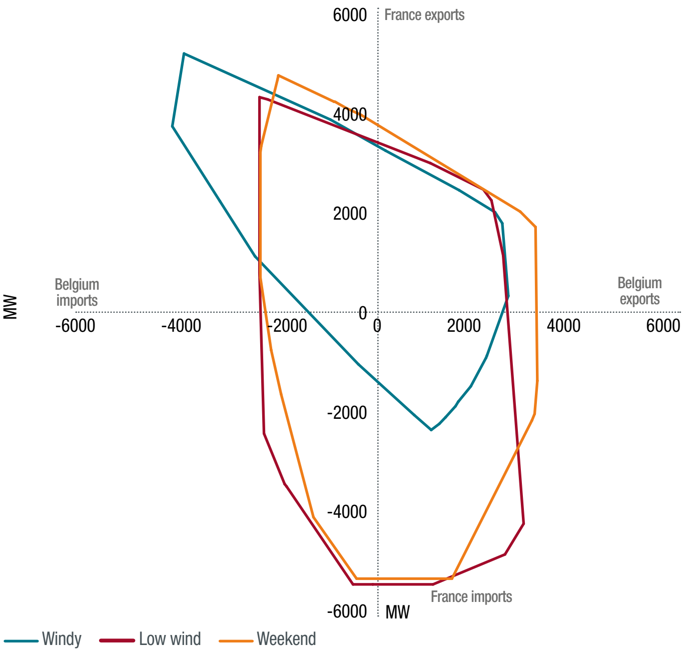
The impact of the long-term loss of a network element is studied as a sensitivity in this study. This can result from extreme weather conditions.

This sensitivity on the flow-based domains was created considering the loss of a pylon between France and Belgium (incident leading to the simultaneous loss of two cross border lines). This outage is assumed for the whole winter.

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 sensitivity test.

The resulting flow-based domains show a high decrease in the maximum import capacity for Belgium in the 'weekend' and 'low wind' domains, accounting for around 2300 MW (see Figure 101). In the case of the 'windy domain', the import capacity can still reach 4000 MW.

FLOW-BASED DOMAINS USED IN THE SENSITIVITY AFTER LOOSING A GRID ELEMENT FOR THE WHOLE WINTER (FIG. 101)



TO WHAT EXTENT CAN WINTER METEOROLOGICAL CONDITIONS POSE A RISK TO THE ELECTRICITY GRID? HOW IS ELIA PREPARING? WHAT IS THE IMPACT ON SECURITY OF SUPPLY?

Power lines are increasingly exposed to specific weather events occurring in recent years. This has been observed not only in Belgium in recent years. Elia has also experienced significantly more problems over the past ten years due to exceptional weather conditions. Examples:

– **Snow deposits** on power lines can occur in very specific and exceptional weather conditions characterised by wind, near zero temperatures and precipitation. These snow deposits on a line, can increase the stresses on the masts up to 500%. This can overturn pylons or result in cables hanging so low, the line cannot be operated safely.

– **Unusual powerful gusts of wind** ('whirlwinds') may manifest as fall winds, which occur very locally and last only a few minutes. Wind speeds can reach as high as 200 km/h to 270 km/h. These winds can cause extremely serious damage to the entire environment: trees, houses, local infrastructure and pylons.

In order to cope with such extreme weather, Elia applies stringent technical standards. For example, the most recent pylons in Belgium – built after 1985 – can withstand winds up to 180 km/h. However damage caused by unusual powerful gusts of wind cannot be ruled out.

In order to cope with the loss of an electric line Elia has emergency lines that can be installed in a short time from several days to weeks depending on the extent of the damage and the access to the site.

5.2

FIXED COMMERCIAL CAPACITY BETWEEN THE CWE ZONE AND NEIGHBOURING COUNTRIES

MODELLING

Countries outside the CWE zone and interconnections between the CWE zone and the rest of Europe are modelled with fixed maximum commercial exchange capacities, also called NTC (Net Transfer Capacities). This is the same as defined today in the day-ahead market.

These capacity values are taken from studies conducted within ENTSO-E and from bilateral and multilateral contacts and take into account planned new interconnections for future winters.

NTCs also vary from day to day depending on the conditions of the network, availability of lines and other network elements. They are regularly updated. In this study, a single reference value is used for a given interconnection in a certain direction during the entire simulated period.

The historical exchange capacities can be found on the websites of the relevant system operators and on ENTSO-E's transparency website [21].

MAXIMUM WINTER IMPORT CAPACITY OF THE CWE ZONE FROM NEIGHBOURING COUNTRIES

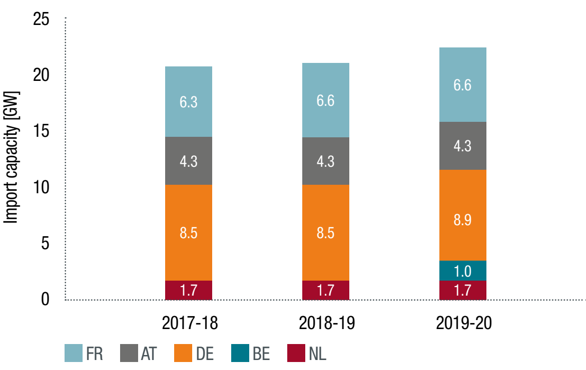
The impact of countries outside the CWE zone on the risk of a structural deficit in Belgium consists of the capacity of these countries to provide energy to the CWE zone in case of a power shortage at CWE level.

The import capacity of the CWE zone taken into account in this study as NTC:

- **France**: Sum of net import capacity in France (outside the flow-based zone) which is considered to be 6.3 GW for winter 2017-18. This value is the sum of that can be imported from Spain, Italy, Switzerland and Great Britain.
- **Netherlands**: Sum of net import capacity of the Netherlands (from outside the flow-based zone) which is considered to be 1.7 GW for winter 2017-18. This value is the sum that can be imported from Norway and Great Britain.
- **Germany and Austria**: Sum of net import capacity from Germany (outside the flow-based zone), which is considered to be 8.5 GW (DE) + 4.3 GW (AT) for winter 2017-18. This value is the sum of the capacity that can be imported from Poland, the Czech Republic, Hungary, Switzerland, Italy, Slovenia, Sweden and Denmark.
- **Belgium**: Sum of net import capacity in Belgium (outside the flow-based zone) which is considered to be for winter 2017-18 is 0 GW. In the 'base case', the future interconnection with Great Britain is taken into account from winter 2019-20 as an additional 1 GW.

The sum of import capacity shown in Figure 102 is the maximum possible import capacity to the CWE region (BE, FR, NL, DE, AT, LU) during winter as assumed in the simulations. The sum of this maximum import capacity (> 20 GW) may seem high. However to have the whole capacity used, the energy must be available in the foreign countries (outside of the CWE zone) in times of structural shortage. As the simulation perimeter includes those countries, the availability of generation is explicitly taken into account.

ASSUMPTIONS REGARDING THE MAXIMUM IMPORT CAPACITY ONLY FROM COUNTRIES OUTSIDE THE CWE ZONE (FIG. 102)



EXCHANGES WITH NON-MODELLED COUNTRIES

No exchanges between modelled countries and non-modelled countries are considered. This is a conservative assumption as such exchanges do exist and could contribute to security of supply for the CWE region. Given the fact that neighbouring countries of the CWE region are modelled in this study (20 countries in total), such exchanges have little impact on the situation in Belgium.

06

RESULTS

This chapter contains the adequacy results for all the scenarios that were performed for the three winters: 2017-18, 2018-19 and 2019-20. It also includes a detailed analysis of the results for the 'base case' scenario for winter 2017-18.

Based on identified uncertainties in chapters 3, 4 and 5, a large number of 'sensitivities' have been conducted for the three winters. These will make it possible to capture any deviations from the 'base case' scenario and quantify the risk. Additionally, following recently released information about the French 'carbon tax' which only became known after the 'base case' scenario assumptions were set, additional sensitivities were conducted for winter 2017-18.

This chapter is divided into three parts:

- Section **6.1** covers the 'base case' scenario;
- Section **6.2** analyses the different sensitivities that were analysed;
- Section **6.3** summarises the results and adds an extra sensitivity given the latest information on French non-nuclear generation facilities.

For each simulated sensitivity, different adequacy indicators are given:

- The criteria defined by law (**LOLE average and LOLE95**), given in hours, rounded off to 15 minutes. The distribution of the LOLE is also presented where the other percentiles can be clearly identified. Additionally a table is given next to the chart which contains P50 and maximum values of LOLE;
- The **Energy Not Served (ENS)**, expressed in GWh, rounded off to decimals, which corresponds to the total energy not served for the simulated winter (based on the energy not served of each of the simulated future states);
- The **probability of a structural shortage** for a given winter reflects the chance of having at least one hour of structural shortage;
- The **need for strategic reserve (positive number) or margin (negative number)** in the system that is needed to reach the adequacy criteria defined by law;
- For some sensitivities, the **number of activations** and the **length of an activation** of a hypothetical volume of strategic reserve are given with average, P95 and maximum values.

6.1 'BASE CASE' SCENARIO

The first scenario labelled the 'base case' was constructed on the basis of the situation known in mid-October 2016. It includes the following assumptions as detailed in chapters 3, 4 and 5:

HYPOTHESES FOR BELGIUM:

- **Thermal generation facilities** as known on 15 October 2016, based on the latest closure announcements by producers (announced at the latest by 31 July 2016 for winter 2017-18). No major changes are taken into account between the three winters under study (92 MW of turbojets are assumed to be decommissioned for winter 2019-20);
- All **nuclear** units are considered available for all winters;
- A **new biomass unit** (400 MW in Langerlo) is taken into account as of winter 2018-19;
- **Market response** is taken into account (same amount as identified in the survey of 2015 – total of 826 MW);
- **RES forecasts** are a best estimate based on a consultation of the regions;
- **CHP** installed capacity is slightly decreased (40 MW decommissioned for winter 2018-19 and an additional 129 MW for winter 2019-20);
- **Demand growth** is around 0%/year for the first years and it is assumed to increase by around +0.6% for 2019-20;
- **Forced outage rates** are based on the observed average over the last ten years.

HYPOTHESES FOR OTHER COUNTRIES:

- **French coal** (2.9 GW) and 2 CCGT (0.9 GW) units are assumed decommissioned (this is a conservative approach as the French 'carbon tax' will most likely not be implemented). This corresponds to a scenario between the 'high' and 'low' scenarios identified by RTE in their mid-term adequacy report [47];

- **French nuclear** units are assumed available (with draws on forced and planned outages as done for all the European production units);
- **Dutch** hypotheses are in line with the latest TenneT adequacy report for the 'base case' scenario [74];
- **German** hypotheses are in line with their latest adequacy report, closure announcements and new built capacity;
- **Great Britain's** assumptions are based on the 2016 FES 'Slow Progression' scenario [27].

INTERCONNECTIONS:

- a new interconnection between Belgium and Great Britain (Nemo Link®) with the capability of exchanging 1000 MW is assumed available for winter 2019-20;
- flow-based modelling with three representative domains for winter 2017-18 is used in this assessment for the CWE region. The maximum import capacity that Belgium can reach in case of favourable market conditions and grid availability is 4500 MW;
- an NTC modelling for the rest of Europe is used.

6.1.1 WINTER 2017-18

6.1.1.1 CALCULATION OF LOLE, ENS AND NUMBER OF ACTIVATIONS

The margin or deficit (i.e. a need for strategic reserve volume) is calculated on both legal criteria (LOLE average and LOLE95). The resulting values are shown in Figure 103. The LOLE average for winter 2017-18 is 45 minutes and the percentile 95 is 1 hour. These results are lower than the criteria defined by law, resulting in a margin of 800 MW in both cases.

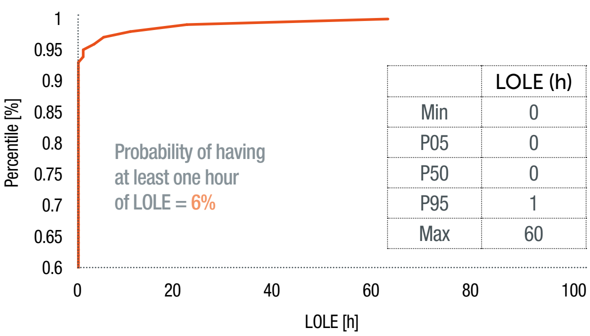
As can also be observed in Figure 103, the number of activations of a possible volume of strategic reserves would be very low: 0.2 times on average, once in P95 and 10 times in the most extreme simulated 'Monte Carlo' year. The figure also indicates the maximum length that a possible volume of strategic reserves would be activated without interruption.

For the most extreme simulated event in all the future states, a possible volume would be activated for a maximum time of 18 hours without interruption. The average of the maximal activation length is around 2.9 hours.

Furthermore, Figure 103 shows that the amount of Energy Not Served (ENS) is limited to 0.4 GWh over the winter on average and to 0.6 GWh in P95.

Figure 104 shows the cumulative distribution of the total simulated 'Monte Carlo' years for the 'base case' scenario when no volume or margin was added. Some other indicators, such as the probability of having at least one hour of structural deficit are shown. This probability amounts to 6% for winter 2017-18. In the most extreme year simulated, 60 hours of structural deficit were obtained. The small table next to the graph indicates the P5, P50 and P95 of the LOLE distribution. In the 'base case' scenario for winter 2017-18, those are all equal to 0 hours, except for the P95 which equals 1 hour.

WINTER 2017-18 – 'BASE CASE' CUMULATIVE DISTRIBUTION OF LOLE WITHOUT STRATEGIC RESERVE (FIG. 104)



WINTER 2017-18 – 'BASE CASE' (FIG. 103)

	AVERAGE	P95
LOLE [h]	0h45	1h00
ENS [GWh]	0.4	0.6
Need or Margin [MW]	-800	-800

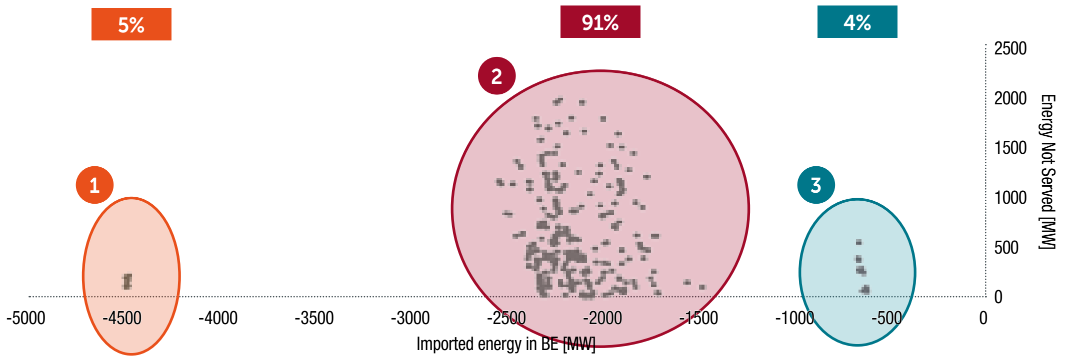
Margin of 800 MW

	AVERAGE	P95	MAX
Number of activations	0.2	1	10
Activation length [h]	2.9	1	18

6.1.1.2 IMPORTS IN PERIODS OF STRUCTURAL SHORTAGE

The hours in which structural shortage is identified in the simulation, can be classified into three categories based on Belgium's imports during these hours. This can be seen in Figure 105. The graph shows the imported energy in Belgium (resulting from the flow-based market coupling) and energy not served in MW for each hour. This graph is based on the 'base case' simulation which has an average LOLE of 45 minutes and where only 6% of the simulated future states have at least one hour of structural shortage.

IMPORTED ENERGY AND ENERGY NOT SERVED IN BELGIUM FOR THE HOURS WITH STRUCTURAL SHORTAGE IN THE 'BASE CASE' SIMULATION (FIG. 105)



1 BELGIUM CAN IMPORT 4500 MW

The first category indicated in Figure 105 represents the hours of structural shortage where Belgium was able to find 4500 MW of energy abroad, but where there is still an energy shortage in the country. The amount of energy not served in those hours is very limited (below 300 MWh in each of those hours).

2 BELGIUM IMPORT'S SALDO IS REDUCED AND THERE IS LOW WIND INFEED IN GERMANY

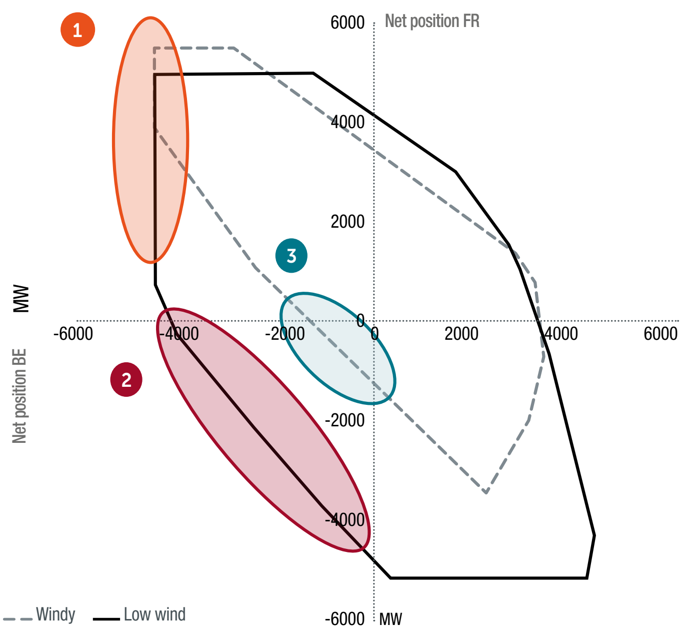
The second category resulting from Figure 105 contains the hours when there is very cold weather and there is a low wind infeed in Germany. There are simultaneous structural shortages in France and Belgium, and these result in a reduced import saldo for Belgium as the energy coming from the CWE region has to be split between the two countries. This second set contains almost all the hours of structural shortage (91%) where energy not served values of up to 2000 MWh can be observed.

3 BELGIUM IMPORT'S SALDO IS REDUCED AND THERE IS HIGH WIND INFEED IN GERMANY

The last category indicated in Figure 105 shows the hours when there is a high wind infeed in Germany corresponding to the 'low wind' domain and therefore applied in the simulation. France and Belgium are in simultaneous structural shortages and this results in a reduced import saldo for Belgium as the energy coming from the CWE region has to be split between the two countries. Amount of energy not served per hour is limited (maximum is around 500 MWh).

The three categories can also be visualised on the flow-based domain representation on the French and Belgian net positions. Belgium's reduced import possibilities when France is in structural shortage trace the flow-based domain border in the third quadrant of the diagram in Figure 106. It is clearly visible how the 'low wind' domain reduces the possibilities of simultaneous French and Belgian imports.

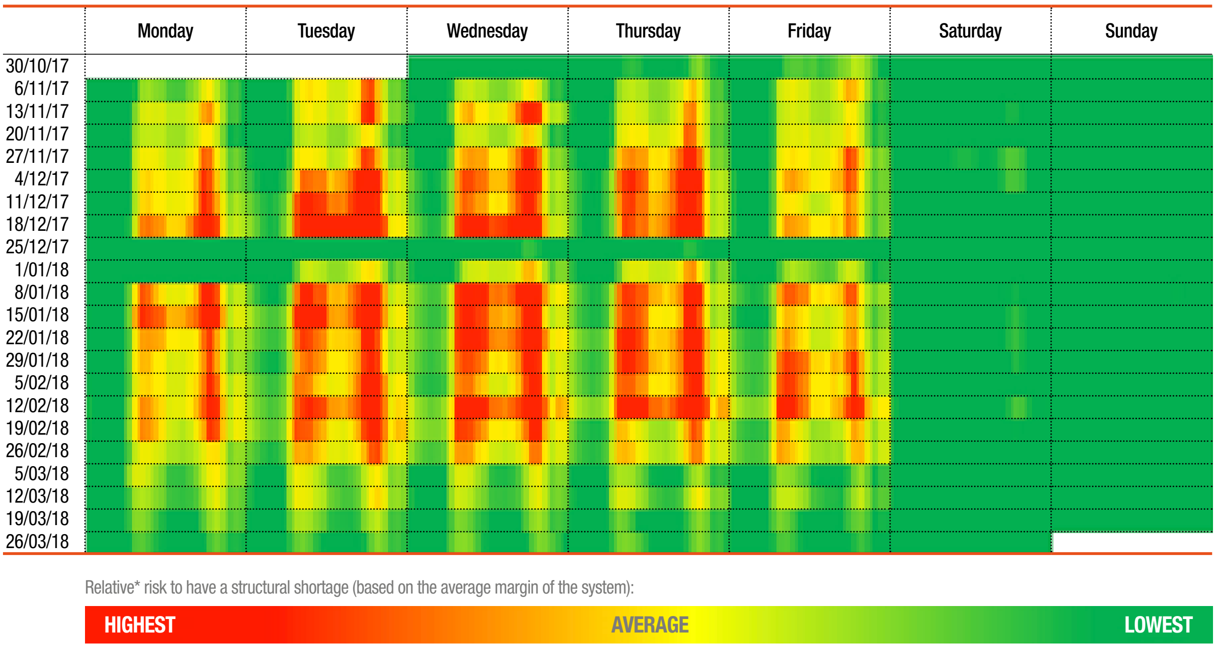
RELATION BETWEEN MOMENTS OF STRUCTURAL SHORTAGE AND IMPORTS SHOWN ON THE FLOW BASED DOMAINS (FIG. 106)



6.1.1.3 WHEN IS A STRUCTURAL SHORTAGE RISK IDENTIFIED?

Given the low probability of having an hour of structural shortage in the 'base case' scenario, the risk of structural shortage has been calculated on the hourly remaining margin of the system without taking into account import capabilities. Figure 107 was constructed for didactic purposes and makes it possible to clearly identify the moments when the risk of structural shortage is the highest. The colour legend shows the relative risks (structural shortages are therefore more likely to happen in hours that are coloured red than hours that are coloured green). In general, the risk follows the residual demand of the country (demand minus non dispatchable generation). Furthermore, effects such as weekday, weekends, peak/off-peak or holidays can be derived from the figure.

RELATIVE RISK TO HAVE A STRUCTURAL SHORTAGE HOUR FOR WINTER 2017-18 BASED ON THE AVERAGE MARGIN ON THE SYSTEM (FIG. 107)

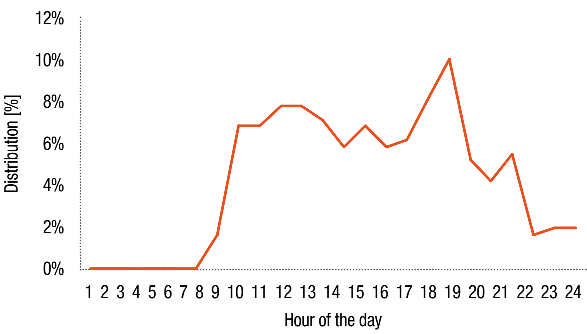


Note that the probability to have a structural shortage for the winter 2017-18 based on the 'base case' assumptions is very low and the legal criteria are satisfied without strategic reserve.
This figure only shows the relative risk between the hours.

Figure 108 shows on which hours of the day there is a risk of a structural shortage occurring (based on the 'base case' simulation used in this study). The risk is only seen from 6 AM when the electricity demand starts to increase before the morning peak. The highest probability of having a structural shortage is during peak hours.

The graphs shown in this section are based on the outputs of the simulations for the 'base case' scenario for winter 2017-18. It is important to mention that the values of these figures can change if the amount of LOLE increases as these two graphs (Figure 107 and Figure 108) are based on the output of simulations for the 'base case' scenario. Although the general trends of the figures will not change drastically, the values represented in the graphs depend, amongst other things, on the number of hours of structural deficit and the available capacity in all the simulated countries.

DISTRIBUTION OF STRUCTURAL SHORTAGE HOURS OVER THE DAY FOR BELGIUM (FIG. 108)



6.1.1.4 MARKET RESPONSE IMPACT ON ADEQUACY

The market response assumptions used in the 'base case' scenario are explained in section 3.2.4. This capacity amounting to 826 MW (mainly a reduction in demand when prices are high), is taken into account with limitations on the amount of activations per day and week.

Figure 109 shows an extreme situation during a week where structural shortages of more than 2000 MW per hour are observed, for several hours in a row and for four days. In such situations, market response is of little help to cover the total energy not served, but will help to reduce the peaks. Increasing the market response capacity in such cases will also not help, unless the limitations on the volume are also increased. During the fifth day of the week, it can be seen that market response makes it possible to cover energy not served, resulting in no structural shortage for that day. This was possible because the amount of hours when market response was needed was limited, and the energy that had to be served was below the market response capacity.

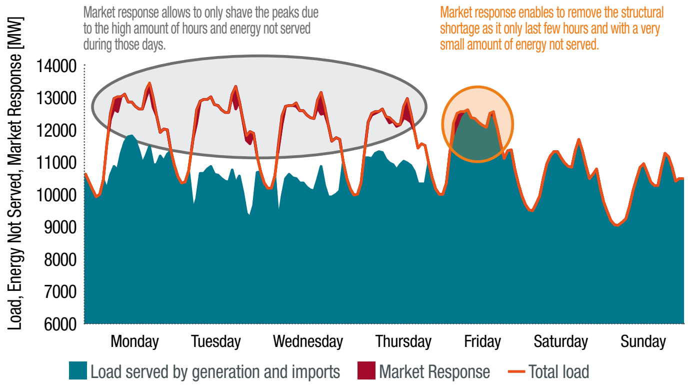
Figure 110 shows a week where the structural shortage is limited to two days. In such situations, market response helps to cover the shortages. However, there are still remaining hours that cannot be covered due to the imposed limitation on the number of activations of such volume taken into account in this study.

6.1.1.5 NEIGHBOURING COUNTRIES' ABILITY TO SUPPLY ENERGY IN CASE OF A STRUCTURAL SHORTAGE IN BELGIUM

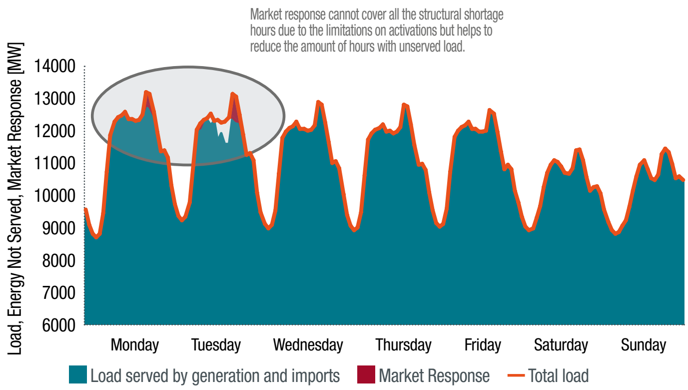
The ability to find energy abroad when there is structural shortage in Belgium is crucial for the Belgium's security of supply, due to Belgium's high dependence on imports for its own adequacy. An analysis of the ability of neighbouring countries to export energy is shown on Figure 111. For the Netherlands, Switzerland, Italy and Spain, the high probability of those countries being able to provide such energy indicates that there are enough margins inside those or in their neighbours. Therefore, they can export energy at maximum to the countries being in a situation of structural shortage. Great Britain has 60% to 90% probability of being able to export energy at full capacity in case of shortage in Belgium. For France, this probability is lower.

The situation of France is further explored in section 6.2.3 with sensitivities pertaining to generation facilities in the country. It is important to note that the values shown on the figure depend on the situation in Belgium and abroad. Lower margins abroad will result in lower probabilities depending on the current situation (if a country has a very high margin, lower production capacity might not directly affect the ability to export, whereas a country with a low margin might be highly affected).

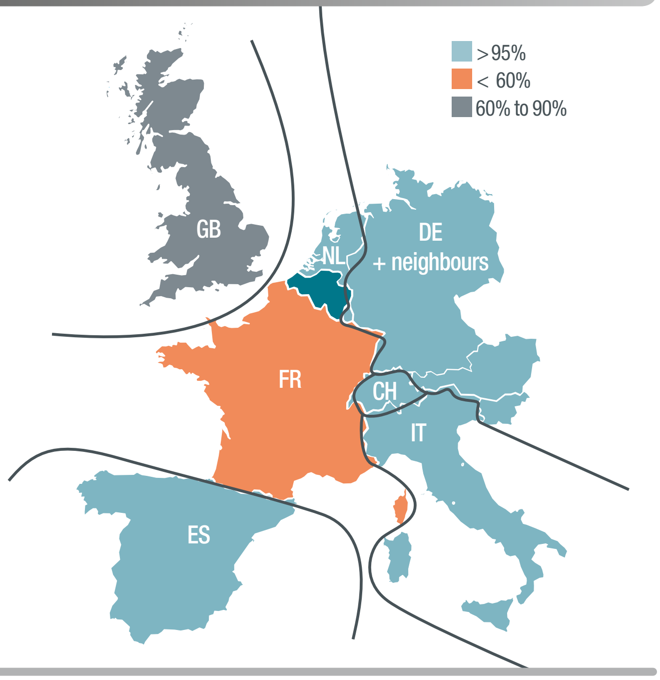
EXCEPTIONAL WEEK OF STRUCTURAL SHORTAGE. IMPACT OF MARKET RESPONSE IS VERY SMALL IN SUCH SITUATIONS DUE TO THE LIMITATIONS OF THIS CAPACITY (IN VOLUME AND ACTIVATIONS) (FIG. 109)



IMPACT OF MARKET RESPONSE IN A GIVEN DAY CAN HELP TO REDUCE STRUCTURAL SHORTAGE IF THOSE LASTS FOR LIMITED HOURS (FIG. 110)



PROBABILITY THAT THE NEIGHBOURING COUTRIES CAN EXPORT AT MAXIMUM CAPACITY WHEN THERE IS STRUCTURAL SHORTAGE IN BELGIUM FOR WINTER 2017-18 (FIG. 111)



6.1.1.6 BELGIAN DEPENDENCE ON IMPORTS FOR ITS ADEQUACY FOR WINTER 2017-18

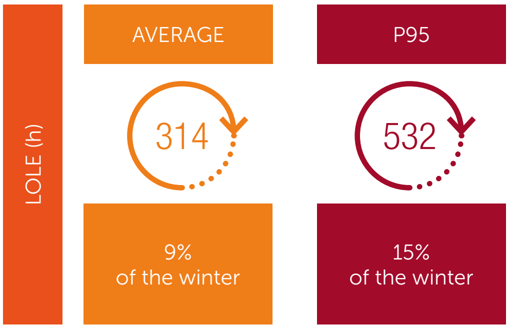
The Belgian Electricity Act does not provide a LOLE criterion for the isolated country. Looking at the LOLE for the fictitious situation where Belgium is considered isolated, reveals the country's dependence on imports for its security of supply. As shown in Figure 112, Belgium needs imports for 314 hours on average and 532 hours in P95 which corresponds respectively to 9% and 15% of the winter.

In reality Belgium can import a large amount of energy thanks to its interconnections (if the energy is available abroad), makes it possible to stay below the criteria defined by the law. The evolution of capacity in neighbouring countries needs to be closely monitored given Belgium's high dependence on imports.

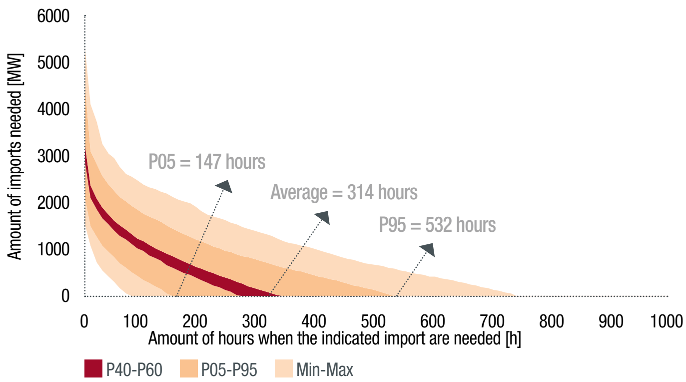
A more detailed analysis of this simulation is illustrated in Figure 113. Values obtained in the previous figure are also indicated. This graph shows the imports needed in order for Belgium to be adequate. Depending on the future state, the amount of energy needed and the amount of hours when imports are needed vary. The distribution of all the evaluated future states is indicated through different ranges.

Belgium needs imports for a minimum of 80 hours to a maximum of around 720 hours in order to be adequate. Very few hours exceed a need above 4500 MW, and there is a need for more than 4500 MW in less than 5% of the future states. The amount of imported energy needed for the most extreme hour of the year oscillates between 1500 and 5300 MW and is around 3000 MW on average.

ISOLATED BELGIUM LOLE VALUES GIVE AN INDICATION ON THE IMPORT DEPENDANCE OF THE COUNTRY FOR ADEQUACY (FIG. 112)



IMPORTS NEEDED FOR BELGIUM TO BE ADEQUATE (AMOUNT OF IMPORTS AND AMOUNT OF HOURS WHEN THOSE ARE NEEDED) BASED ON THE ISOLATED SIMULATION OF BELGIUM (FIG. 113)



6.1.2 WINTER 2018-19

The main changes for winter 2018-19 compared to winter 2017-18 that are included in the 'base case' assumptions are:

- The inclusion of Langerlo biomass unit (400 MW). A sensitivity on this assumption is analysed in section 6.2.2.3;
- No changes in Belgium's thermal generation facilities. By law, units have to announce their closure before 31 July 2017 for winter 2018-19 and therefore the available generation facilities will only be known by that time. Additional closures are taken into account in the sensitivity analysed in section 6.2.2.2;
- A stable (around 0%/year) total demand evolution in Belgium. Higher demand growth sensitivity is analysed in section 6.2.1.2.

Given the changes for Belgium (and the trend of generation and demand for the neighbouring countries as listed in chapter 4), the margin on the Belgian system is expected to be higher than for winter 2017-18.

Figure 114 compiles the results for winter 2018-19 according to the 'base case' assumptions. The LOLE average is 15 minutes, and the ENS is equal to 0.1 GWh on average. P95 values (and P50 values) are all equal to 0 for both LOLE and ENS. A margin of 1300 MW according to the average criteria and 1400 MW according to the P95 criteria are identified. Taking into account the most restrictive criterion (the average), this results in a margin of 1300 MW.

The number of activations is very low (0.1 on average) and the maximum observed in all the future states is eight times per year. The maximal activation length can be as much as 14 hours in case of structural shortage.

WINTER 2018-19 – 'BASE CASE' (FIG. 114)

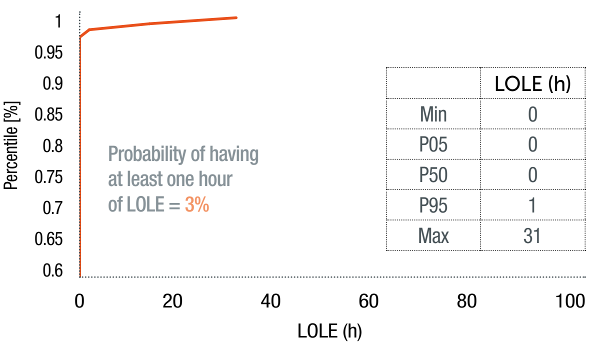
	AVERAGE	P95
LOLE [h]	0h15	0h00
ENS [GWh]	0.1	0
Need or Margin [MW]	-1300	-1400

Margin of 1300 MW

	AVERAGE	P95	MAX
Number of activations	0.1	0	8
Activation length [h]	2.2	0	14

The LOLE distribution for the futures states obtained for the 'base case' winter 2018-19 is shown on Figure 115. The maximum amount of LOLE obtained in the most extreme simulated future state (most extreme winter from the total set of winters) is 31 hours. The probability of having a structural shortage is 3%. This means that for 97% of the simulated winters, there is no LOLE observed (and therefore LOLE in P50 is also 0).

WINTER 2018-19 – 'BASE CASE' CUMULATIVE DISTRIBUTION OF LOLE WITHOUT STRATEGIC RESERVE (FIG. 115)



	LOLE (h)
Min	0
P05	0
P50	0
P95	1
Max	31

6.1.3 WINTER 2019-20

The main change for winter 2019-20 compared to winter 2018-19 that is used in the 'base case' assumptions, is the commissioning of the Nemo Link® between Great Britain and Belgium. A sensitivity pertaining to this hypothesis is analysed in section 6.2.5.1. Other changes include higher offshore wind capacity in Belgium (an increase of 850 MW compared to the previous winter) and a very slight increase in the total Belgian demand.

With these assumptions, a margin of 2100 MW is identified for Belgium for winter 2019-20. The LOLE average is below 15 minutes and the LOLE in P95 is equal to zero. There are still 3% of the future states that have a risk of structural shortage.

Detailed results are shown on Figure 116 and cumulative distribution and percentiles are given in Figure 117.

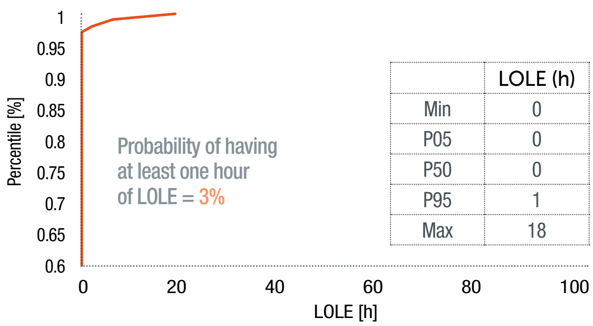
WINTER 2019-20 – 'BASE CASE' (FIG. 116)

	AVERAGE	P95
LOLE [h]	<0h15	0h00
ENS [GWh]	0.1	0
Need or Margin [MW]	-2100	-2200

$\underbrace{-2100 \quad -2200}_{\text{Margin of 2100 MW}}$

	AVERAGE	P95	MAX
Number of activations	0.1	0	8
Activation length [h]	1.6	0	9

WINTER 2019-20 – 'BASE CASE' CUMULATIVE DISTRIBUTION OF LOLE WITHOUT STRATEGIC RESERVE (FIG. 117)

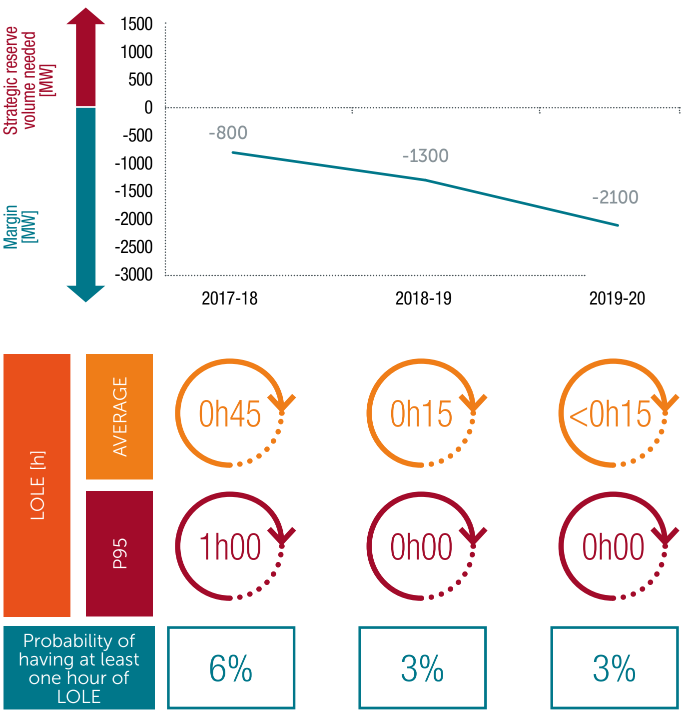


	LOLE (h)
Min	0
P05	0
P50	0
P95	1
Max	18

6.1.4 SUMMARY OF THE RESULTS FOR THE 'BASE CASE' SCENARIO

Figure 118 summarises the LOLE average, P95, the margin on the system and the probability of having one hour of structural shortage for the next three winters in the 'base case' scenario taken into account in this study. The margin of 800 MW in 2017-18 rises to 2100 MW in winter 2019-20. The LOLE average stays below 1 hour for all three winters. The LOLE P95 is 0 hours in 2018-19 and 2019-20 as the probability of having a structural shortage hour is lower than 5%.

ADEQUACY INDICATORS FOR THE 'BASE CASE' SCENARIO (FIG. 118)



6.2 SENSITIVITIES

Future is highly uncertain and different assumptions from those used in the 'base case' scenario could lead to different values of margin or need for strategic reserve. Therefore, 15 sensitivities have been carried out capturing the uncertainty of several parameters that could affect Belgium's adequacy. These sensitivities are listed in Figure 119 below, and are all based on the 'base case' scenario meaning that for each one, only the given parameter has been changed compared to the 'base case' scenario.

Following recent information released about the French 'carbon tax' and the recent high level of unavailability of the nuclear fleet, a combination of those sensitivities has been analysed too. The results of this analysis can be found in section 6.3.

All sensitivities presented on section 6.2 are based on the scenario labelled as 'base case' in this study. This scenario assumes the introduction of a 'carbon tax' in France leading to a decommissioning of 2.9 GW of coal and an additional 0.9 GW of CCGT given uncertainty on a CRM in France.

'BASE CASE' AND SENSITIVITIES SUMMARY (FIG. 119)

	'Base Case'	Sensitivity	
Low Market Response	826 MW with activation limitations	577 MW with activation limitations	Section 6.2.1
Demand growth	Stable (0%/year)	High growth (0.6%/y)	Section 6.2.1
Nuclear availability	All nuclear units available	Absence of 2 GW nuclear for the whole winter	Section 6.2.2
Higher FO rates in BE	Forced outage rates calculated average of 2006-15	Max observed in past 10 years for CCGT & Nuclear	Section 6.2.2
Late commissioning Langerlo Biomass	Commissioned for 2018-19	Commissioned after 2019-20	Section 6.2.2
Generation facilities	Known closure annoucements	Additional closure of 600 MW in 2018-19 and 2019-20	Section 6.2.2
French coal and gas generation facitilities	Coal capacity (2.9 GW) and gas (0.9 GW) removed	'high' RTE scenario. 3.8 GW more capacity	Section 6.2.3
French coal and gas generation facilities	Coal capacity (2.9 GW) and gas (0.9 GW) removed	'low' RTE scenario. Additional removal of gas capacity (3.1 GW)	Section 6.2.3
French nuclear availability	All nuclear units available (with planned and forced outages taken into account)	Absence of 9 nuclears units for the whole winter	Section 6.2.3
Dutch generation facilities	Reference scenario TenneT	1.5 GW removal	Section 6.2.4
Flow based domain	All grid elements available	Long term loss of a critical grid element	Section 6.2.5
Late commissioning NEMO link	Commissioned for 2019-20	Commissioned after 2019-20	Section 6.2.5
	'Base case' without French Carbon tax	**Sensitivity**	
French coal and gas generation facitilities	All nuclear units available (with planned and forced outages taken into account)	Absence of 9 nuclears units for the whole winter	Section 6.3
Nuclear availability	All nuclear units available	Absence of 1 GW nuclear for the whole winter	Section 6.3
		Combination of the previous 2	Section 6.3

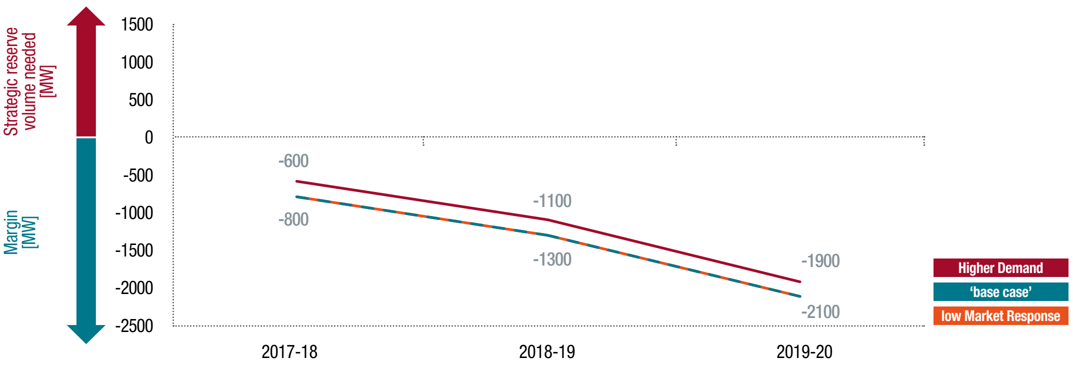
6.2.1 SENSITIVITIES ON THE BELGIAN DEMAND

Two sensitivities were analysed with respect to Belgian demand:

- A lower market response capacity (250 MW less than the 826 MW taken into account in the 'base case' scenario);
- A higher demand growth (around 0.54 % growth per year instead of 0% per year).

Those changes were separately applied to the 'base case' scenario. The results in terms of margin and need for strategic reserve are shown on Figure 120. Lower market response than the one used in the 'base case' has no impact on the adequacy indicators. This is in line with the explanations given in section 6.1.1.4. A higher demand growth results in around 200 MW of margin decrease over the three next winters.

RESULTS OF SENSITIVITIES ON DEMAND ASSUMPTIONS FOR BELGIUM (FIG. 120)



'Base case': total demand growth around 0%/year
'Low Market response': lower market response capacity (250 MW less than in 'base case')
'Higher Demand': total demand growth around +0.6%/year

6.2.1.1 SENSITIVITY TO THE AVAILABLE CAPACITY OF MARKET RESPONSE

Reducing market response by around 250 MW has a very limited impact on the margin calculated in the 'base case', given the low amount of LOLE observed in that scenario. The market response limitations on the number of activations per day and week were kept when removing capacity. As explained in section 6.1.1.4, either an increase in the limitations used or a significant change in market response capacity will have an impact on the calculated need or margin. This also shows that the remaining hours of structural shortages in the different future states are hours with either:

- a high amount of energy not served (reducing the market response by 250 MW has no impact); or
- a high number of successive hours (the limitations on the number of activations per day and week are more constraining than the amount of capacity itself).

It is important to note that market response would have a bigger impact on a scenario where the initial LOLE values are higher.

The results are the same as seen for the 'base case' scenario. The only difference is the probability of having at least one hour of LOLE for a given winter which increases by 1% in 2017-18 (6% in the 'base case', 7% in this sensitivity). The other changes cannot be captured by the other adequacy indicators (given the fact that they are averaged to 15 minutes for the LOLE, to decimals for the ENS and to 100 MW for the need/margin).

It is important to note that taking into account higher amounts of market response capacity reduction or changing the limitations might result in higher impact on adequacy results.

SENSITIVITY TO LOWER MARKET RESPONSE (FIG. 121)

	Winter 2017-18		Winter 2018-19		Winter 2019-20	
	AVERAGE	P95	AVERAGE	P95	AVERAGE	P95
LOLE [h]	0h45	0h00	0h15	0h00	<0h15	0h00
ENS [GWh]	0.4	0.6	0.1	0	0.1	0
Probabilty to have at least one hour of LOLE	7%		3%		3%	
Need [+] or Margin [-] [MW]	-800	-800	-1300	-1400	-2100	-2300

6.2.1.2 HIGHER GROWTH FOR BELGIAN DEMAND

The 'base case' scenario assumes a stable demand for the next two winters followed by a 0.6% increase for winter 2019-20. This sensitivity considers an increase in demand of at least 0.54% for all winters. All the values can be found in section 3.2.1 more specifically in Figure 64.

With these assumptions about Belgian demand, the margin decreases by 200 MW for each of the winters. All the other adequacy indicators increase slightly in comparison to the 'base case'. Figure 122 summarises the results for this sensitivity for the three studied winters.

SENSITIVITY WITH A HIGHER LOAD IN BELGIUM (FIG. 122)

	Winter 2017-18		Winter 2018-19		Winter 2019-20	
	AVERAGE	P95	AVERAGE	P95	AVERAGE	P95
LOLE [h]	1h00	3h00	0h30	0h00	0h15	0h00
ENS [GWh]	0.6	0.9	0.2	0	0.1	0
Probabilty to have at least one hour of LOLE	7%		4%		3%	
Need [+] or Margin [-] [MW]	-600	-600	-1100	-1200	-1900	-2100

6.2.2 SENSITIVITIES WITH RESPECT TO BELGIAN GENERATION FACILITIES

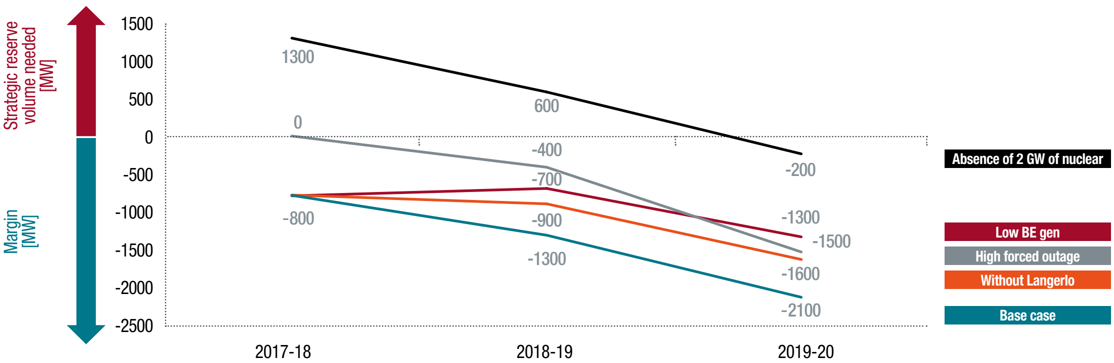
Changes in the Belgian generation facilities have a direct impact on the country's adequacy. Availability of the thermal generation facilities is modelled by taking into account forced outages: a different sequence of availability is drawn for each production unit and for each simulated 'Monte Carlo' year. This makes it possible to capture the variability of the available capacity in all the countries due to technical failures of power plants. For Belgium, the forced outage rates are calculated on the basis of historical availability data per type of unit, as discussed in section 3.1.3.2. For other countries, these rates are in line with those used in European adequacy studies (see section 1.7 for more information on such studies).

The sensitivities performed with respect to the Belgian generation facilities include:

- a 600 MW reduction in existing units for winters 2018-19 and 2019-20 that could reflect possible additional closures in the future. The generation capacity for winter 2017-18 is known following the announcements that the producers are required to carry out before 31 July 2016;
- higher forced outages for CCGT and nuclear power plants using the maximum rate observed in the past ten years;
- late commissioning of the Langerlo biomass power plant (400 MW) considered in the 'base case' scenario for winter 2018-19;
- the absence of 2 GW from the nuclear power fleet for the whole winter (on top of normal forced outages).

The results for these four sensitivities in terms of margin and strategic reserve volume requirements are illustrated in Figure 123. In sections 6.2.2.1 to 6.2.2.4, further elaboration is given on each of the four sensitivities.

RESULTS OF SENSITIVITIES ON BELGIAN GENERATION FACILITIES (FIG. 123)



'Base case': 2017-18 generation facilities assumptions stay stable (with minor changes in the future winters). Full nuclear availabilty (with forced outages), inclusion of Langerlo biomass from winter 2018-19
'High forced outage': Forced outage rates of CCGT and nuclear units were set to the maximum observed in the past 10 years
'Low BE gen': considering additional closures of thermal units for an amount of 600 MW for 2018-19 and 2019-20
'Absence of 2 GW of nuclear'
Without Langerlo

6.2.2.1 FURTHER REDUCTION IN BELGIUM'S EXISTING THERMAL PRODUCTION CAPACITY

As was indicated in section 3.1.3.1, producers had to indicate by 31 July 2016 for each Belgian production unit with a CIPU contract whether or not it would be available for winter 2017-18. However, this obligation does not apply to winters 2018-19 and 2019-20. Therefore, a sensitivity is studied for those two winters in which 600 MW less thermal capacity is available compared to the 'base case' scenario.

Figure 124 shows the results of this sensitivity in terms of LOLE, ENS, and probability of having at least one hour of LOLE. Also, the figure indicates the margin or need for a volume of strategic reserves for the two winters under study. A margin of 700 MW is identified for winter 2018-19, and for winter 2019-20 this sensitivity yields a margin of 1300 MW or 1400 MW depending on the criterion used.

SENSITIVITY WITH RESPECT TO LOWER BELGIAN GENERATION FACILITIES BASED ON HYPOTHETICAL DECOMMISSIONINGS (FIG. 124)

	Winter 2017-18	Winter 2018-19		Winter 2019-20	
		AVERAGE	P95	AVERAGE	P95
LOLE [h]	Not simulated as the generation facilities are known for this winter (closures had to be announced before 31 July 2016)	1h00	2h00	0h30	<0h15
ENS [GWh]		0.5	0.4	0.3	0
Probabilty to have at least one hour of LOLE		6%		5%	
Need [+] or Margin [-] [MW]		-700	-700	-1400	-1300

6.2.2.2 HIGHER FORCED OUTAGE RATES OF THE BELGIAN THERMAL GENERATION FACILITIES

For the 'base case' scenario, unplanned unavailability of Belgian thermal production units is modelled with forced outage rates calculated using availability data from the last ten years (see section 3.1.3.2 for more information on this). In order to analyse the impact of these forced outage rates, a sensitivity with higher rates for the CCGT and nuclear production types has been conducted for all three winters under study. For both production types, the highest observed forced outage rate over the past ten years was used in this analysis. The outage rates used in this sensitivity are given in Figure 125, together with those used in the 'base case' scenario.

FORCED OUTAGE RATES USED IN THE SENSITIVITY WITH HIGHER FORCED OUTAGE RATES FOR THE BELGIAN GENERATION FACILITIES (FIG. 125)

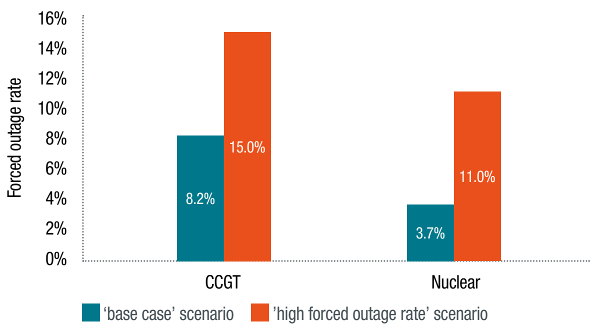


Figure 126 shows the results of the sensitivity with higher forced outage rates for the Belgian production units for winter 2017-18. It can be observed from the figure that with these forced outage rates, there is no margin nor need for strategic reserves identified for this winter. The average LOLE equals 3 hours, with an expected unserved energy of 2.4 GWh. In Figure 127, the distribution of the LOLE is shown for all simulated future states. The figure shows that in approximately 90% of the simulated 'Monte Carlo' years, no loss of load was detected. Amongst all simulated future states, the one with the highest number of hours where loss of load was detected had 130 hours of LOLE.

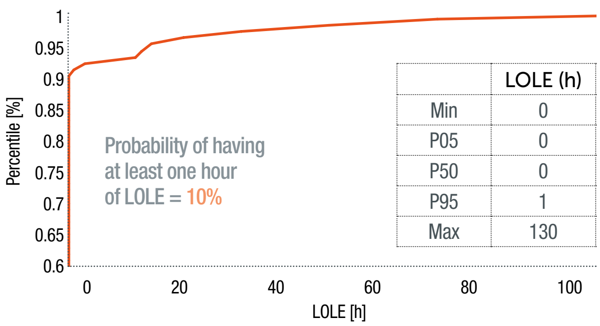
WINTER 2017-18 – SENSITIVITY TO HIGHER FORCED OUTAGE RATES IN BELGIUM FOR NUCLEAR AND CCGTS (FIG. 126)

	AVERAGE	P95
LOLE [h]	3h00	16h00
ENS [GWh]	2.4	7.7
Need or Margin [MW]	0	-100

Margin of 0 MW

	AVERAGE	P95	MAX
Number of activations	0.5	4	13
Activation length [h]	5.3	12.1	66

WINTER 2017-18– SENSITIVITY TO HIGHER FORCED OUTAGE RATES FOR BELGIAN NUCLEAR AND CCGTS: CUMULATIVE DISTRIBUTION OF LOLE WITHOUT STRATEGIC RESERVE (FIG. 127)



	LOLE (h)
Min	0
P05	0
P50	0
P95	1
Max	130

The results for the sensitivity to a higher forced outage rate for the Belgian CCGT and nuclear production units are given in Figure 128 for the three winters studied. Whereas for winter 2017-18 no margin was detected, for winter 2018-19 a margin of 400 MW is identified. For winter 2019-20, the margin changes to 1500 MW for this sensitivity. Furthermore, it can be seen that the average LOLE drops from 3 hours for winter 2017-18, to eventually 30 minutes for winter 2019-20.

SENSITIVITY TO HIGHER FORCED OUTAGE RATE IN BELGIUM FOR NUCLEAR AND CCGTS (FIG. 128)

	Winter 2017-18		Winter 2018-19		Winter 2019-20	
	AVERAGE	P95	AVERAGE	P95	AVERAGE	P95
LOLE [h]	3h00	16h00	1h45	7h00	0h30	1h00
ENS [GWh]	2.4	7.7	1.3	1.5	0.3	0.1
Probabilty to have at least one hour of LOLE	10%		7%		6%	
Need [+] or Margin [-] [MW]	0	-100	-400	-500	-1500	-1700

6.2.2.3 SENSITIVITY TO THE COMMISSIONING OF THE LANGERLO BIOMASS POWER PLANT

As indicated in section 3.1.2.1, in the 'base case' scenario it is expected that a 400 MW biomass conversion of the Langerlo power plant will be operational in time for winter 2018-19. At the time of writing, Elia has no information indicating that this will not be the case. However given its large installed capacity, the decision was made to study the impact on the Belgian adequacy of a possible late commissioning of that plant.

The results of this sensitivity to the commissioning of the Langerlo biomass unit are shown in Figure 129 for both winter 2018-19 and winter 2019-20. For winter 2018-19, the identified margin in this sensitivity equals 900 MW, a reduction of 400 MW compared to the 'base case' scenario. The reduction of the margin for winter 2019-20 compared to the 'base case' scenario equals 500 MW, for an identified 1600 MW of margin in the sensitivity with respect to the late commissioning of the Langerlo biomass unit.

SENSITIVITY WITHOUT LANGERLO BIOMASS UNIT (FIG. 129)

	Winter 2017-18	Winter 2018-19 AVERAGE	Winter 2018-19 P95	Winter 2019-20 AVERAGE	Winter 2019-20 P95
LOLE [h]	Not simulated as the unit should be commissioned for winter 2018-19	0h45	0h00	<0h15	0h00
ENS [GWh]		0.4	0	0.1	0
Probabilty to have at least one hour of LOLE		4%		5%	
Need [+] or Margin [-] [MW]		-900	-1000	-1700	-1600

6.2.2.4 SENSITIVITY TO THE LOSS OF 2 GW OF NUCLEAR UNITS FOR THE WHOLE WINTER

In section 3.1.3.2, the exceptional outages that occurred for the Belgian nuclear power plants in 2014 and 2015 were mentioned. Due to the large installed capacity of these nuclear units (over 1 GW for four of the eight Belgian units), they have a very significant impact on the Belgian adequacy. Therefore, a sensitivity has been analysed in which 2 GW of nuclear units are considered out of operation for the total duration of the winter.

It should be noted that the outage of the 2 GW of nuclear capacity comes on top of the outages modelled for all Belgian thermal units with a CIPU contract (see section 3.1.3.2). Therefore, in some of the simulated future states there are situations with more than 2 GW of nuclear out of operation. For the same reason, simulated future states for the 'base case' scenario also have situations where 2 GW or more of nuclear capacity is unavailable.

Figure 130 shows the results of the sensitivity in which 2 GW of nuclear capacity was removed compared to the 'base case' scenario for the three winters under study. For winters 2017-18 and 2018-19 a need for strategic reserves of 1300 MW and 600 MW respectively is identified in this sensitivity. This need for strategic reserves evolves in a slight margin of 200 MW in winter 2019-20. The probability of experiencing at least one hour of loss of load in Belgium is 22% for winter 2017-18, and evolves to 10% for winter 2019-20.

SENSITIVITY TO THE ABSENCE OF 2GW NUCLEAR CAPACITY IN BELGIUM (FIG. 130)

	Winter 2017-18 AVERAGE	Winter 2017-18 P95	Winter 2018-19 AVERAGE	Winter 2018-19 P95	Winter 2019-20 AVERAGE	Winter 2019-20 P95
LOLE [h]	6h45	49h15	5h00	45h15	2h15	10h00
ENS [GWh]	7.2	62.0	4.0	30.0	1.5	3.9
Probabilty to have at least one hour of LOLE	22%		14%		10%	
Need [+] or Margin [-] [MW]	1200	1300	600	600	-200	-300

6.2.3 SENSITIVITIES TO THE AVAILABLE THERMAL GENERATION CAPACITY IN FRANCE

Given recent events affecting the availability of French nuclear units and the uncertainties surrounding the 'carbon tax' and capacity remuneration mechanism in France, several scenarios were created to evaluate their impact.

French assumptions were made prior to the French government's announcement that it would not implement the 'carbon tax' for coal-fired power plants. In the 'base case' scenario, the coal-fired power plants were removed (2.9 GW) along with 2 CCGT units (0.9 GW) for a total of 3.8 GW less capacity compared to the 'high' scenario developed by RTE in their adequacy report.

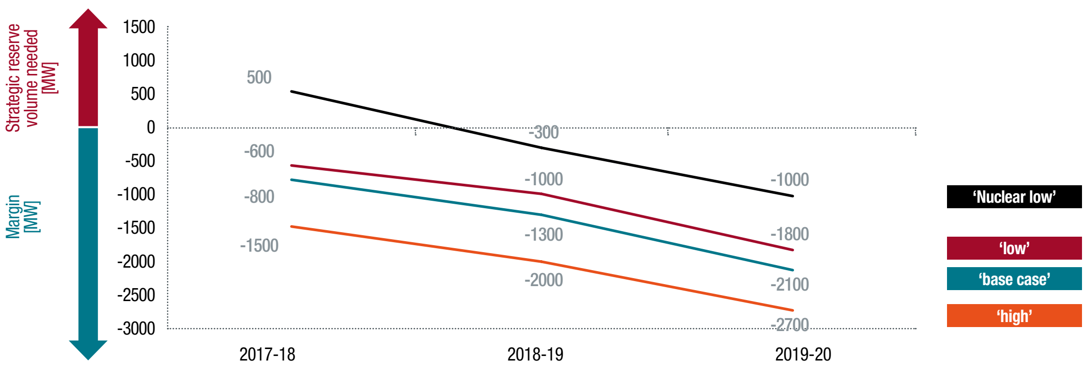
Given the most recent information on the 'carbon tax' and the capacity remuneration mechanism implementation for the year 2017, the 'base case' can be considered conservative.

The recent high unavailability of nuclear units due to inspections by the French Nuclear Safety Agency (ASN) (see section 4.1.1 for more information) was also assessed for the whole time horizon with nine nuclear units removed (totalling 8.1 GW).

The results of those sensitivities in terms of need or margin in the system for Belgium are shown on Figure 131.

For winter 2017-18, only the scenario with lower nuclear availability indicates a need for strategic reserve. For the next two winters, all scenarios are below the LOLE criteria and there is still a margin.

RESULTS OF SENSITIVITIES ON FRENCH GENERATION FACILITIES ASSUMPTIONS (FIG. 131)



'High': 'high' scenario from RTE latest adequacy report assuming all coal and gas units in the market
'Base case': removal of coal (2.9 GW) and 2 CCGTs (0.9 GW) from the 'high' scenario
'Low': additional unavailability of 2.1 GW of gas and 1 GW of decentralised production from the 'base case'
'Nuclear low': additional unavailability of 9 nuclear units on top of the 'base case' scenario

6.2.3.1 'LOW' FRENCH COAL AND GAS SCENARIO

The 'low' French coal and gas scenario assumes:

- A 'carbon tax' for coal power plants leading to the complete closure of those units (2.9 GW), also assumed in the 'base case' scenario;
- The non-implementation of the capacity remuneration mechanism in France leading to the closure of 3 GW of gas fired units (of which 0.9 GW was also taken into account in the 'base case' scenario) and 1 GW of decentralised production.

In total, 7 GW of production capacity is removed from the generation facilities compared to the 'high' scenario and 3 GW compared to the 'base case' scenario.

The results shown on Figure 132 indicate a margin of 600 MW in winter 2017-18 which is 200 MW lower than the 'base case'. The other adequacy indicators are slightly higher than the 'base case'.

SENSITIVITY TO THE 'LOW' THERMAL GENERATION FACILITIES FOR FRANCE (ASSUMING A 'CARBON TAX' AND NO 'CRM' (FIG. 132)

	Winter 2017-18		Winter 2018-19		Winter 2019-20	
	AVERAGE	P95	AVERAGE	P95	AVERAGE	P95
LOLE [h]	1h15	4h15	0h30	0h00	0h15	0h00
ENS [GWh]	0.6	1.3	0.2	0	0.2	0
Probabilty to have at least one hour of LOLE	7%		4%		4%	
Need [+] or Margin [-] [MW]	-600	-600	-1000	-1000	-1800	-1800

6.2.3.2 'HIGH' FRENCH COAL AND GAS SCENARIO

The 'high' scenario taken from RTE's latest adequacy report assumes no 'carbon tax' and a capacity remuneration mechanism in France allowing power plants to have enough revenues and stay in the market. This scenario has around 4 GW more installed capacity than the 'base case' considered in this study. The margin increases by 700 MW compared to the 'base case' for winter 2017-18 reaching 1500 MW. The probability of having a structural shortage drops to 3%.

SENSITIVITY TO THE 'HIGH' THERMAL GENERATION FACILITIES FOR FRANCE (ASSUMING NO 'CARBON TAX' AND A 'CRM') (FIG. 133)

	Winter 2017-18		Winter 2018-19		Winter 2019-20	
	AVERAGE	P95	AVERAGE	P95	AVERAGE	P95
LOLE [h]	<0h15	0h00	<0h15	0h00	<0h15	0h00
ENS [GWh]	<0.1	0	<0.1	0	<0.1	0
Probabilty to have at least one hour of LOLE	3%		2%		2%	
Need [+] or Margin [-] [MW]	-1500	-1600	-2000	-2100	-2700	-2700

6.2.3.3 SENSITIVITY TO THE AVAILABILITY OF THE FRENCH NUCLEAR PRODUCTION CAPACITY

Recent events in 2016 led to a low nuclear availability during the beginning of winter 2016-17 and probably for a substantial part of it. More detailed information is given in section 4.1.1.

For this sensitivity, nine nuclear units, of 900 MW each, were assumed to be out (in addition to the 'base case' scenario) leading to a need for 500 MW of strategic reserve in Belgium for winter 2017-18. In this case, the LOLE is equal to 5h15 and P95 to 35h15. Average activations and average length are equal to 1.5 and 2.9 hours respectively. The other detailed results are shown in Figure 134.

WINTER 2017-18 – SENSITIVITY TO THE FRENCH NUCLEAR FLEET (ABSENCE OF 9 UNITS) (FIG. 134)

	AVERAGE	P95
LOLE [h]	5h15	35h15
ENS [GWh]	3	20.7
Need or Margin [MW]	400	500

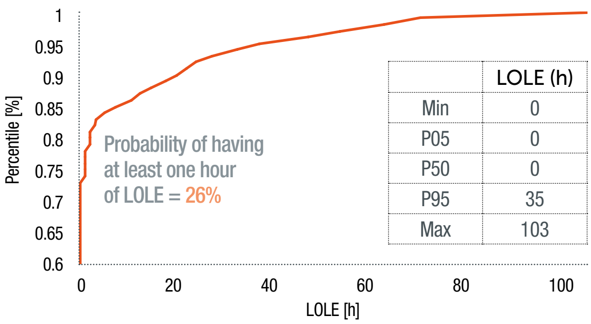
Strategic reserve volume of 500 MW needed

	AVERAGE	P95	MAX
Number of activations	1.5	10	22
Activation length [h]	2.9	13	30

The LOLE cumulative distribution (without adding capacity nor margin) is shown in Figure 135 together with the different percentiles. The probability of having at least one hour of structural shortage is much higher than in the 'base case' scenario and equal 26%, which means that a structural shortage could occur once every four years in this scenario.

The results for the other winters (see Figure 136) indicate a margin for winters 2018-19 and 2019-20 although the probability of having at least one hour of structural shortage is 14% for winter 2018-19 and 8% for winter 2019-20.

WINTER 2017-18 – SENSITIVITY TO THE FRENCH NUCLEAR FLEET (ABSENCE OF 9 UNITS) CUMULATIVE DISTRIBUTION OF LOLE WITHOUT STRATEGIC RESERVE (FIG. 135)



	LOLE (h)
Min	0
P05	0
P50	0
P95	35
Max	103

SENSITIVITY TO THE FRENCH NUCLEAR FLEET (ABSENCE OF 9 UNITS) (FIG. 136)

	Winter 2017-18		Winter 2018-19		Winter 2019-20	
	AVERAGE	P95	AVERAGE	P95	AVERAGE	P95
LOLE [h]	5h15	35h15	1h45	9h00	0h45	3h00
ENS [GWh]	3.0	20.7	0.8	2.6	0.3	0.8
Probabilty to have at least one hour of LOLE	26%		14%		8%	
Need [+] or Margin [-] [MW]	400	500	-300	-300	-1000	-1000

6.2.4 SENSITIVITY TO AVAILABLE THERMAL GENERATION CAPACITY IN THE NETHERLANDS

Following TenneT's adequacy report as explained in section 4.2, a sensitivity to the removal of 1500 MW capacity has been taken into account for the Netherlands.

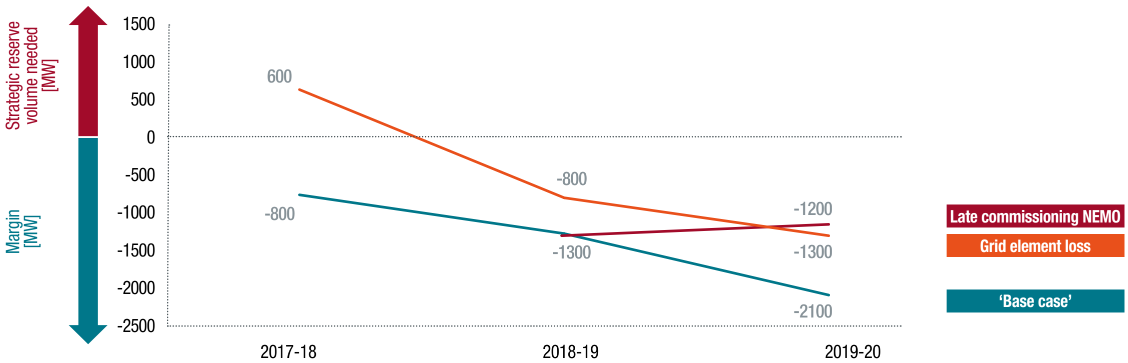
Due to the comfortable margins that the Netherlands has for winter 2017-18, removing capacity does not yet affect Belgium's adequacy results. Further decommissioning could have an impact in the future and should be assessed. The results are exactly the same (following the accuracy used in this study) as for the 'base case' scenario.

6.2.5 SENSITIVITY TO THE INTERCONNECTION CAPACITY

The 'base case' scenario assumes that Belgium can import 4500 MW from the flow-based zone if market conditions are favourable and under normal operating grid conditions. The modelling involves three representative flow-based domains used for each day of the simulation depending on the type of day (weekday or weekend) and the wind infeed in Germany (see section 5.1 for more information). Moreover, the new interconnector between Great Britain and Belgium that should be commissioned during the year 2019 is taken into account for winter 2019-20. A sensitivity was performed to analyse the impact of a commissioning of the Nemo Link® after winter 2019-20.

In order to assess the impact of losing a critical grid element for the whole winter, sensitivity was performed by removing two cross border lines between France and Belgium (loss of a pylon) for the whole winter. This will result in a lower maximum import and lead to a need for strategic reserve in winter 2017-18 when applying it to the 'base case' scenario (see Figure 137).

RESULTS OF SENSITIVITIES TO GRID AND INTERCONNECTIONS ASSUMPTIONS (FIG. 137)



'Base case': no major long term outage on the grid and NEMO link considered for winter 2019-20
'Late commissioning NEMO': NEMO link interconnection between GB and BE not ready for winter 2019-20
'Grid element loss': loss of a critical grid element for the whole winter period

6.2.5.1 SENSITIVITY TO THE NEMO LINK® INTERCONNECTOR

The new interconnector between Belgium and Great Britain was included in the 'base case' scenario for winter 2019-20. The late commissioning of this link will lead to a lower margin (1200 MW) compared to the margin of 2100 MW obtained in the 'base case' scenario.

Detailed results for winter 2019-20 are shown in Figure 138. The LOLE average is 30 minutes and P95 equals zero.

WINTER 2019-20 – SENSITIVITY WITHOUT NEMO LINK (BE-GB INTERCONNECTION) (FIG. 138)

	AVERAGE	P95
LOLE [h]	0h30	0h00
ENS [GWh]	0.3	0
Need or Margin [MW]	-1200	-1300

Margin of 1200 MW

	AVERAGE	P95	MAX
Number of activations	0.2	0	9
Activation length [h]	2.7	0	18

6.2.5.2 LONG-TERM LOSS OF A GRID COMPONENT

The 'base case' scenario simulates possible exchanges between countries in the CWE zone with the same flow-based method as used in the Day-Ahead market (see section 5.1). Representative domains are used to replicate possible situations.

International agreements require that the N-1 criterion be satisfied at all times, including during maintenance or repair work on a network element. Of course, such situations are avoided as much as possible during critical periods, such as around the winter peak, but can never be completely ruled out. For instance winter weather conditions may lead to a long-term loss of a network element. These exceptional phenomena are not taken into account in the representative domains used to calculate the volume of strategic reserve in the 'base case' scenario. However, this section gives the impact of the prolonged loss of a network element in the flow-based domain and hence the need for strategic reserve. The construction of those domains is explained in section 5.1.8.

The impact of a different set of representative domains (following the loss of a grid element) can differ depending on the available production capacity in the CWE zone as well as in Belgium.

In this case (see Figure 139), applying the representative domains obtained after the loss of a grid element, the need for strategic reserve is 600 MW, LOLE average equals 8 hours and P95 equal to 37 hours. If such a situation occurs (probability of occurrence being already quite low) in winter 2017-18, the probability of having a structural shortage is 37% (one in three years).

For the following winters, the need disappears and is replaced by a margin of 800 MW in 2018-19 and 1200 MW in 2019-20. The probability remains below 5% and LOLE values below 1 hour for the average.

SENSITIVITY TO THE REPRESENTATIVE FLOW-BASED DOMAINS (FIG. 139)

	Winter 2017-18		Winter 2018-19		Winter 2019-20	
	AVERAGE	P95	AVERAGE	P95	AVERAGE	P95
LOLE [h]	8h00	37h00	0h30	0h00	0h15	0h00
ENS [GWh]	4.3	27.0	0.1	0	0.1	0
Probabilty to have at least one hour of LOLE	37%		4%		3%	
Need [+] or Margin [-] [MW]	600	600	-800	-800	-1400	-1300

6.3

SUMMARY OF RESULTS FOR WINTER 2017-18 AND EXTRA SENSITIVITIES BASED ON THE MOST RECENT INFORMATION

Given the recent unusual nuclear unavailability in France due to inspections and the prolonged nuclear forced outage in Belgium and based on the latest information regarding the 'carbon tax' and the possible capacity remuneration mechanism in France, Elia has performed additional sensitivities not covered in section 6.2.

Starting with the 'high' French scenario for coal and gas (no 'carbon tax' and most probably a capacity remuneration mechanism set for 2017), the margin on the Belgian system is 1500 MW for winter 2017-18 as indicated in section 6.2.3.2.

If the situation of winter 2016-17 would be replicated for winter 2017-18 with an extension of the current planned and forced outages of nuclear units in Belgium and France, which means considering:

- nine nuclear units in planned maintenance (in addition to normal maintenance) in France for the whole winter; and
- one nuclear unit in Belgium (1 GW) in maintenance or in forced outage for the whole winter (in addition to normal forced outages).

This would lead to a need for strategic reserve of 900 MW.

Taking into account one of those events separately does not lead to a need of strategic reserve.

These findings are summarised in Figure 145 (in the conclusions).

6.3.1 'HIGH' FRENCH COAL AND GAS WITH THE ABSENCE OF NINE NUCLEAR UNITS FOR THE WHOLE WINTER

In a situation where nine French nuclear units would be out of the system for the whole winter in addition to the 'high' French coal and gas scenario, this would result in a margin of 100 MW for Belgium. LOLE average equals 2h30 and LOLE P95 is equal to 14 hours. The probability of having structural shortage is 10% (once in ten years).

WINTER 2017-18 – 'HIGH' RTE SCENARIO (WITH CRM AND NO 'CARBON TAX') WITH THE ABSENCE OF 9 NUCLEAR UNITS IN FRANCE (FIG. 140)

	AVERAGE	P95
LOLE [h]	2h30	14h00
ENS [GWh]	1.3	7
Need or Margin [MW]	-100	-100

Margin of 100 MW

	AVERAGE	P95	MAX
Number of activations	0.7	6	19
Activation length [h]	3.6	6	42

6.3.2 'HIGH' FRENCH COAL AND GAS WITH THE ABSENCE OF ONE NUCLEAR UNIT IN BELGIUM

The absence of one Belgian nuclear units of 1 GW on top of the 'high' French scenario for coal and gas capacity would lead to a margin of 600 MW. The other adequacy parameters are summarised in Figure 141.

WINTER 2017-18 – 'HIGH' RTE SCENARIO (WITH CRM AND NO 'CARBON TAX') WITH THE ABSENCE OF 1 NUCLEAR UNIT IN BELGIUM (FIG. 141)

	AVERAGE	P95
LOLE [h]	0h45	4h00
ENS [GWh]	0.6	1.2
Need or Margin [MW]	-600	-600

Margin of 600 MW

	AVERAGE	P95	MAX
Number of activations	0.3	2	7
Activation length [h]	3.1	3	19

6.3.3 'HIGH' FRENCH COAL AND GAS WITH THE ABSENCE OF ONE NUCLEAR UNIT IN BELGIUM AND NINE NUCLEAR UNITS IN FRANCE

A scenario combining both the absence of nine nuclear units in France and one nuclear unit in Belgium for the whole winter leads to a strategic reserve need of 900 MW (where the P95 criteria is the most restrictive).

The table in Figure 142 indicates that LOLE average is 7h45 and LOLE P95 is 68h15. The amount of energy not served is 6.1 GWh on average. The average number of activations is 1.3 and the maximum observed in all the future states is 22 times per winter. The longest activation needed (taking into account all the hours of all future states) is 66 hours. The average activation length is equal to 5 hours.

WINTER 2017-18 – 'HIGH' RTE SCENARIO (WITH CRM AND NO 'CARBON TAX') WITH THE ABSENCE OF 9 NUCLEAR UNITS IN FRANCE AND 1 IN BELGIUM (FIG. 142)

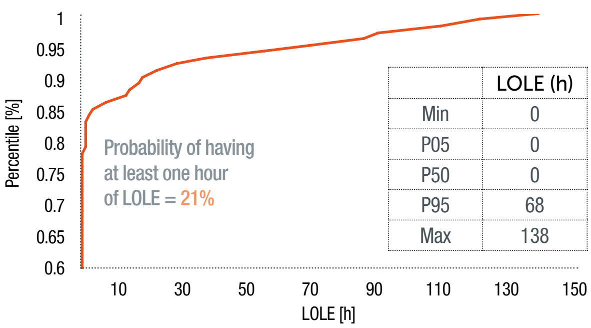
	AVERAGE	P95
LOLE [h]	7h45	68h15
ENS [GWh]	6.1	53.6
Need or Margin [MW]	800	900

Strategic reserve volume of 900 MW needed

	AVERAGE	P95	MAX
Number of activations	1.3	9	22
Activation length [h]	5	18	66

The cumulative distribution of this scenario is given in Figure 143. The probability of having at least one hour of structural shortage in Belgium is 21% (once every five years). The maximum LOLE observed is 138 hours.

WINTER 2017-18 – 'HIGH' RTE SCENARIO (WITH CRM AND NO 'CARBON TAX') WITH THE ABSENCE OF 9 NUCLEAR UNITS IN FRANCE AND 1 IN BELGIUM CUMULATIVE DISTRIBUTION (FIG. 143)



	LOLE (h)
Min	0
P05	0
P50	0
P95	68
Max	138

07

CONCLUSIONS

This report gives an estimate of the needed capacity to be contracted as strategic reserve in order to maintain Belgium's adequacy below the criteria defined by law for winters 2017-18, 2018-19 and 2019-20. If no volume was identified, the margin for each scenario was calculated.

Elia has performed a probabilistic analysis following the planning defined by law to allow the Federal Minister of Energy to make a decision on the needed volume by 15 January 2017.

The assumptions used in this report were set on 15 October 2016 and include the best available estimates for installed generation capacities in Belgium and neighbouring countries at the time of collecting the assumptions.

THE 'BASE CASE' SCENARIO:

The 'base case' scenario, as it is called in this study, describes the most likely trend in Belgian generation facilities given the information that Elia collected, which was discussed with the Federal Public Service prior to 15 October 2016 as required by law and was submitted to a public consultation in September 2016. It includes the following assumptions (only the main drivers for Belgium are listed below):

- stable total demand for Belgium;
- RES forecasts based on the latest data from the regions;
- a 400 MW increase from winter 2018-19 following the new biomass power plant in Langerlo;
- the commissioning of the new interconnector with Great Britain (Nemo Link®) as of winter 2019-20;
- the full availability of nuclear units (taking into account forced outage rates);
- stable trend in the rest of Belgium's thermal generation facilities with a small decrease in capacity for winter 2019-20. Assumptions for winter 2017-18 are fixed as units had to announce their closure before 31 July 2016.

In the 'base case' also a standard availability of the French nuclear power plants, and the closure of some 4 GW of thermal plants expected as a result of uncertain market conditions and the likely introduction of a 'carbon tax', are taken into account.

For the 'base case' scenario, such as defined in this report, the need for strategic reserve is equal to 0 MW as a margin of 800 MW was obtained for the country.

A LARGE NUMBER OF INDIVIDUAL SENSITIVITIES WAS ASSESSED IN ADDITION TO THE 'BASE CASE' SCENARIO:

The results from the 'base case' scenario do not take into account unexpected maintenance of nuclear units nor additional closures. Those effects were assessed separately as sensitivities in this study. Other uncertainties about assumptions were captured by analysing a large number of individual sensitivities, such as:

- higher demand growth in Belgium;
- lower market response capacity;
- higher forced outage rates for CCGT and nuclear units in Belgium;
- the loss of a grid element for the whole winter;
- the unavailability of 2GW nuclear units for the whole winter in Belgium;
- the unavailability of 9 nuclear units in France for the whole winter;
- additional closures of thermal units in France;
- additional closures in the Netherlands;
- additional closures in Belgium after winter 2017-18;
- the late commissioning of the Langerlo biomass unit;
- the late commissioning of the Nemo Link® interconnector between Great Britain and Belgium.

These can be found in the report with detailed results for each winter.

'BASE CASE', SENSITIVITIES RESULTS FOR WINTER 2017-18 (FIG. 144)

	'Base Case'	Sensitivity	LOLE [h] AVERAGE	LOLE [h] P95	Need (+) or Margin (-) [MW]
Low Market Response	826 MW with activation limitations	577 MW with activation limitations	0h45	1h00	-800
Demand growth	Stable (0%/year)	High growth (0.6%/year)	1h00	3h00	-600
Nuclear availability	All nuclear units available	Absence of 2 GW nuclear for the whole winter	6h45	49h15	1300
Higher FO rates in BE	Forced outage rates calculated average of 2006-15	Max observed in past 10 years for CCGT & Nuclear	3h00	16h00	0
Late commissioning Langerlo Biomass	Commissioned for 2018-19	Commissioned after 2019-20	not relevant for 2017-18		
Generation facilities	Actual closures annoucements known	Further closure of 600 MW in 2018-19 and 2019-20	not relevant for 2017-18		
French coal and gas generation facitilities	Coal capacity (2.9 GW) and gas (0.9 GW) removed	'high' RTE scenario. 3.8 GW more capacity	<0h15	0h00	-1500
French coal and gas generation facilities	Coal capacity (2.9 GW) and gas (0.9 GW) removed	'low' RTE scenario. Additional removal of gas capacity (3.1 GW)	1h15	4h15	-600
French nuclear availability	All nuclear units available (with planned and forced outages taken into account)	Absence of 9 nuclears units for the whole winter	5h15	35h15	500
Dutch generation facilities	Reference scenario TenneT	1.5 GW removal	0h45	1h00	-800
Flow based domain	All grid elements available	Long term loss of a critical grid element	8h00	37h00	600
Late commissioning NEMO link	Commissioned for 2019-20	Commissioned after 2019-20	not relevant for 2017-18		
	'Base case' without French Carbon tax	**Sensitivity**			
French nuclear availability	All nuclear units available (with planned and forced outages taken into account)	Absence of 9 nuclears units for the whole winter	2h30	14h00	-100
Nuclear availability	All nuclear units available	Absence of 1 GW nuclear for the whole winter	0h45	4h00	-600
		Combination of the 2	7h45	68h15	900

ADDITIONAL SENSITIVITIES FOLLOWING LATEST INFORMATION AND WINTER 2016-17 SITUATION:

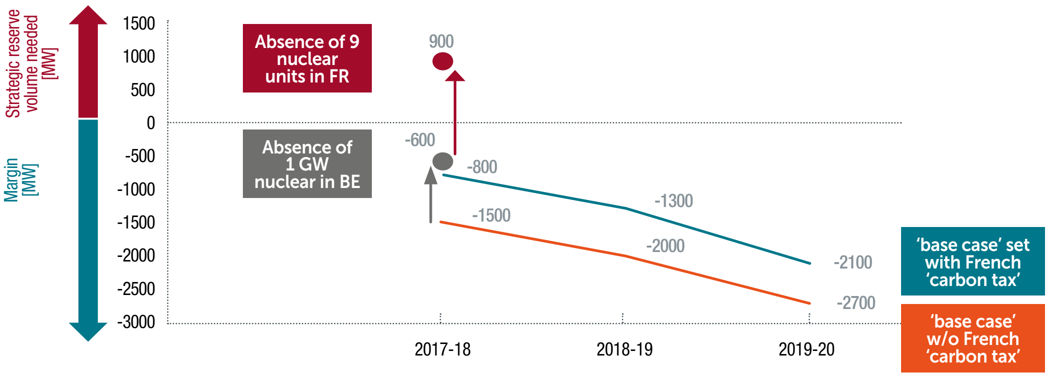
Following recent information about France and the situation for winter 2016-17 (as known in November 2016), an additional combination of sensitivities was assessed. In particular, recent developments in France deserve specific attention and have impact on the need for strategic reserve in Belgium. On the one hand, the French government announced that it will not pursue the introduction of a 'carbon tax'. On the other hand, on average nine nuclear reactors are expected to be unavailable over winter 2016-17 in France. This follows the unexpected extension of some maintenance by the producer, as well as additional shut downs at the request of the French nuclear safety authority. At this this, the potential consequences beyond the current winter are unknown. In addition, in the first weeks of winter period 2016-17, the CWE region experienced a number of situations with limited simultaneous import capabilities for Belgium and France. The root causes of these recent events are currently under investigation in close cooperation with CWE TSOs.

A number of sensitivity analyses were run to evaluate the impact of potential alternative assumptions, and also of the recent developments regarding generation in France and Belgium.

The 'base case' without French 'carbon tax' leads to a margin of 1500 MW in Belgium. Unavailability of 1 GW nuclear capacity in Belgium for the whole winter period, combined with the additional absence of nine nuclear units in France would lead to a need to contract a strategic reserve volume of 900 MW. This combination of sensitivities could reflect the current situation of winter 2016-17 if some of the unavailable units in November 2016 would (need to) extend their maintenance or outage.

These findings are summarised in Figure 145.

RESULTS FOR 'BASE CASE' WITHOUT FRENCH CARBON TAX AND IMPACT OF THE ABSENCE OF 1 GW BELGIAN AND 9 FRENCH NUCLEAR UNITS DURING THE WHOLE WINTER (FIG. 145)



RECOMMENDATION FOR WINTER 2017-18:

These two unavailability hypotheses have a major impact on the results and evolve almost daily. In view of this rapidly changing context, Elia recommends taking a decision based on the latest available information known on 15 January 2017. Concretely, if by that date the above-mentioned units did not receive approval from the competent authorities to restart and/or did not have the perspective on their full availability for winter 2017-18, Elia suggests considering this last scenario and its conclusions, i.e. a need for 900 MW of strategic reserve.

TRENDS FOR WINTERS 2018-19 AND 2019-20:

Results for winters 2018-19 and 2019-20 show an increase of the margin for all the scenarios for Belgium (and therefore a decrease of the risk of having a structural shortage). These calculations were based on the most recent data and information. Additional closures in Belgium and abroad could lead to lower margins in the future. Even if most of the sensitivities show a margin for those winters, a combination of them could result in a need for strategic reserve. More precise results will be computed in next year's report for winter 2018-19.

IN ADDITION TO THESE RESULTS, SOME ITEMS FOR ATTENTION CAN BE DEDUCTED FROM THIS STUDY:

- Belgium remains dependent on imports for its security of supply. This means that any change in the assumptions in neighbouring countries has a potential impact on the results for Belgium. This was assessed with lower assumptions for generation facilities in France and the Netherlands and it can be seen that there is a strong correlation between Belgium and France in terms of security of supply.
- The calculations are made without taking into consideration the maintenance of thermal units in Belgium for the winter (maintenance for 2017 is taken into account following the latest planning but only for winter 2017-18). Elia tries to plan all maintenances outside of winter, in consultation with the producers. This also applies to the maintenance and construction of grid upgrades for Elia's critical network infrastructure. The plans for all of these works outside the winter months, in addition to the drop in units available on the market, means that scheduling these operations becomes more critical and can lead to difficult times for supply outside the winter period (November–March).

WHEN INTERPRETING THE RESULTS ACCOUNT SHOULD BE TAKEN OF THE FOLLOWING KEY ASSUMPTIONS:

- The calculated volume does not distinguish between reductions in demand or production capacity. The volume is calculated on the basis of the assumption that this volume is 100% present. This is an important hypothesis, especially for large volumes;
- Volume is calculation without taking into account the possibility of being able to find such volume effectively in Belgium. The margin or deficit (need for strategic reserve volume) is calculated so as to fulfil both legal criteria (LOLE average and LOLE P95).

Elia wishes to emphasise that the conclusions of this report are inseparable from the assumptions that are mentioned in this report. Elia cannot guarantee that these assumptions are realised. These are in most cases developments beyond the direct control and the responsibility of the system operator.

08

ABBREVIATIONS

A>Z

aFRR: automatic Frequency Restauration Reserve

ANTARES: A New Tool for Adequacy Reporting of Electric Systems

ARP: Access Responsible Party

ASN: Autorité de Sûreté Nucléaire

BRP: Balance Responsible Party

CASC: Capacity Allocating Service Company

CB: Critical Branch

CCG: CWE Consultative Group

CCGT: Combined Cycle Gas Turbine

CEER: Council of European Energy Regulators

CfD: Contracts for Difference

CHP: Combined Heat & Power

CIPU: Contract for the Injection of Production Units

CM: Capacity Market

CORESO: Coordination of Electricity System Operators

CPF: Carbon Price Floor

CREG: Commission for Electricity and Gas Regulation

CRM: Capacity Remuneration Mechanism

CWE: Central West Europe

DG: Directorate-General

DSO: Distribution System Operator

ECN: Energy research Centre of the Nederlands

EMR: Electricity Market Reform

ENS: Energy Not Served

ENS95: Energy Not Served for a statistically abnormal year (95th percentile)

ENTSO-E: European Network of Transmission System Operators for Electricity

EPR: European Pressurised Reactor

FANC: Federal Agency for Nuclear Control

FB: Flow-Based

FCR: Frequency Containment Reserve

FES: Future Energy Scenarios

FPS: Federal Public Service

GDP: Gross Domestic Product

GT: Gas Turbine

GU: Grid User

HVDC: High Voltage Direct Current

IA: Impact Assessment

IHS CERA: Information Handling Services Cambridge Energy Research Associates

LOLE: Loss Of Load Expectation

LOLE95: Loss Of Load Expectation for a statistically abnormal year (95th percentile)

LOLP: Loss Of Load Probability

LWR: Least Worst Regret

MAF: Mid-term Adequacy Forecast

mFRR: manual Frequency Restauration Reserve

NCDC: National Climatic Data Center

NEV: Nationale EnergieVerkening

NTC: Net Transfer Capacity

OCGT: Open Cycle Gas Turbine

PLEF: Pentalateral Energy Forum

PST: Phase Shifting Transformer

PV: Photovoltaic

RES: Renewable Energy Sources

RoR: Run-of-river

RSS: Really Simple Syndication

RTE: Réseau de Transport d'Electricité (French transmission system operator)

SBR: Supplemental Balancing Reserves

SDR: Strategic Demand Reserve

SGR: Strategic Generation Reserve

SO&AF: Scenario Outlook and Adequacy Forecast

SR: Strategic Reserve

TSO: Transmission System Operator

TYNDP: Ten Year Network Development Plan

UC: Unit Commitment

09

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