ADEQUACY STUDY FOR BELGIUM

The need for strategic reserve for winter 2018-19

and outlook for 2019-20 and 2020-21

NOVEMBER 2017

FOREWORD

Dear reader,

During the winter period 2014-15 the strategic reserve mechanism was for the first time constituted at the request of the Federal government, as a measure to safeguard the Belgian security of supply during the winter period, specifically between 1 November and 31 March. This new mechanism was designed to cover structural generation shortages after a number of generation facilities had disappeared from the Belgian market.

Though this reserve production capacity - available 'out of the market' - during these years has not been activated, we may not assume there is no actual need for the strategic reserve volume. For instance, the cold spell in January 2017 combined with an exceptional unavailability of the French nuclear park pushed the Belgian energy system to its limits, with price peaks and nearly activating the strategic reserve.

Each year Elia delivers a probabilistic analysis on Belgium's adequacy for the following winter, as defined in the Electricity Act, to assess the need for a strategic reserve. In this latest report, the security of supply for the next winter 2018-19 is analysed, while giving preliminary indications on the need during the winter periods 2019-20 and 2020-21. We have brought a number of adjustments to the methodology used and to the report, after numerous interactions with stakeholders. The Federal Minister for Energy will use this analysis as one of the elements to decide on the need for strategic reserve during winter 2018-19, a decision to be made before 15 January 2018.

With a view to an increased transparency, publication of the Elia analysis is now scheduled six weeks earlier than defined by the legal process, i.e. at the end of November.

In this report, some sensitivities are taken up on top of the 'base case' scenario. These sensitivities mainly relate to the availability of the nuclear plants in Belgium and in France, as well as operating conditions of a given generation unit (Drogenbos) in Belgium. Considering these 'low-probability events with a high-impact on Belgian adequacy', a firm need for a volume of strategic reserve is identified for the winter 2018-19. This need for strategic reserve is expected to be decreased as of winter 2019-20, with the commissioning of Nemo Link®.

Elia therefore recommends fulfilling the need for 500 MW or 600 MW of strategic reserve for the entire winter 2018-19, depending on the operation of Drogenbos.

We also want to draw the attention of the reader to Elia's most recent study 'Electricity Scenarios for Belgium towards 2050', published on 15 November 2017. With a view to the planned nuclear phase-out in 2025, this study identifies for each long term future scenario a need for additional adjustable (thermal) generation capacity to be able to cope with the shock of the nuclear exit and to guarantee Belgian security of supply.

We wish you a pleasant reading,

Kind regards

Chris Peeters

CONTENTS

EXECUTIVE SUMMARY

As provided for in the Electricity Act, Elia must submit by 15 November of each year a probabilistic analysis of Belgium's adequacy for the following winter. This analysis is an important element to be taken into account by the Federal Minister for Energy to make the decision on the need for a volume of strategic reserve. The deadline for the latter decision for winter 2018-19 runs until 15 January 2018.

This report provides a probabilistic assessment of Belgium's security of supply under several hypotheses and the corresponding need for strategic reserve for the next winter period 2018-19, and also gives a preliminary indication of the need for subsequent winter periods 2019-20 and 2020-21.

The 'base case' scenario - as it is called in this study - includes the following assumptions (only the main drivers for Belgium are listed below):

- a relatively limited growth of 0.5% per year in Belgium's total demand;
- full availability of nuclear units (normal forced outage rates were taken into account, without accounting for exceptional outages as experienced over the last five winters);
- photovoltaic and onshore wind forecasts based on the latest data from the regions, combined with a best estimate made by Elia and FPS Economy for the offshore wind;
- exchanges between Belgium and the other CWE countries are modelled using historical flow-based domains, modified to take into account grid investments in CWE up to winter 2018-19;
- a maximum simultaneous import capacity of 4500 MW for Belgium for winter 2018-19, increasing to 5500 MW for winters 2019-20 and 2020-21;
- the commissioning of the new interconnector with Great Britain (Nemo Link®) with a capacity of 1000 MW from winter 2019-20 onward;
- a stable trend in the remaining thermal generation facilities in Belgium between winter 2017-18 and winter 2018-19, with a small decrease in thermal capacity for both winter 2019-20 and winter 2020-21. The assumptions for winter 2018-19 are fixed, as units had to announce their closure at the latest on 31 July 2017.

Belgium remains dependent on imports for its electricity supply. Therefore any change in the assumptions in neighbouring countries has a potential impact on Belgium and on the associated strategic reserve volume.

Due to the large installed capacity of Belgian nuclear units, their availability has a very significant impact on Belgian adequacy. Forced outage rates used in calculations are based on historical unplanned unavailability for the last ten years. Exceptional long-lasting outages that occurred for Belgian nuclear power plants between 2014 and 2017 were not included in forced outage rates in the 'base case' scenario due to the unusual nature of those outages. Given their significant impact, however, it is important to analyse a scenario taking into account such low-probability, high-impact events. To that end, a detailed comparison of the modelled availability with the real Belgian nuclear availability over the last five winters was conducted.

As a result of this analysis, it is concluded that low-probability, high-impact events, as observed during the last five winters, can be properly captured by considering a sensitivity with 1 GW of nuclear production capacity out of service for the entire winter in Belgium.

Also, unavailability in the French nuclear power fleet has an impact on the adequacy situation in Belgium, as was seen last winter 2016-17 when multiple nuclear units were temporarily out of service at the request of the French nuclear safety authority.

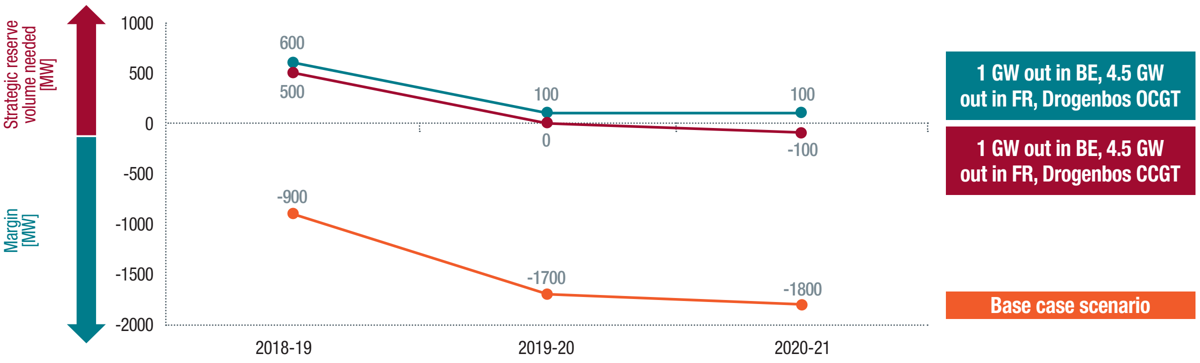
Consequently, the same analysis as for Belgium was conducted for French nuclear availability. When comparing the modelled French nuclear availability in the 'base case' scenario with real French nuclear availability over the last five winters, it became apparent that a sensitivity with 4.5 GW of nuclear production capacity out of service for the entire winter in France should be studied.

In addition, the 'base case' scenario takes the Drogenbos power plant into account as an OCGT[1] production unit with a capacity of 230 MW. However, the production unit can also operate in a CCGT[2] configuration with a capacity of 460 MW. Over the course of winter 2016-17 it was observed that the unit changed its normal OCGT operating mode to CCGT. As announced by the owner of the Drogenbos plant, the same conversion is planned for part of winter 2017-18. Consequently, the sensitivity to Belgian and French nuclear availability was combined as well with a sensitivity to the operation of the Drogenbos power plant as CCGT during the entire winter.

The 'base case' scenario in the study leads to a margin of 900 MW, with an average LOLE of 45 minutes and a LOLE95 of two hours. **Under the assumptions made for this 'base case' scenario, the analysis does not identify a need to contract strategic reserve for winter 2018-19 in order to meet the legal criteria.**

1. Open-Cycle Gas Turbine.
2. Combined Cycle Gas Turbine.

RESULTS FOR THE 'BASE CASE' SCENARIO, AS WELL AS FOR THE SENSITIVITIES ON BELGIAN AND FRENCH NUCLEAR AVAILABILITY FOR DROGENBOS OPERATING BOTH AS CCGT AND OCGT



When applying the abovementioned sensitivity analysis in order to capture low-probability, high-impact events, i.e. where 1 GW nuclear capacity would be unavailable in Belgium and 4.5 GW in France for the entire winter (in addition to historically standard forced-outage rates), and where the Drogenbos unit is operating in OCGT mode, **this would lead to a strategic reserve volume need of 600 MW. If the Drogenbos unit is operating in CCGT mode during the entire winter, the identified need is 500 MW**.

Concerning winters 2019-20 and 2020-21, the margin on the system will increase, mainly thanks to the expected commissioning of the Nemo Link® interconnector by winter 2019-20.

This shows for the 'base case' scenario an indicative increased margin of up to 1700 MW for winter 2019-20 and 1800 MW for winter 2020-21. The LOLE average remains below one hour for both winters. The LOLE P95 is two hours in 2019-20 and three hours in 2020-21.

The same sensitivity analysis that was conducted for winter 2018-19 indicates for winters 2019-20 and 2020-21 a relatively small need of 100 MW when Drogenbos is operating in OCGT mode. When Drogenbos is operating in CCGT mode, no need or margin is identified for winter 2019-20 and a margin of 100 MW is identified for winter 2020-21.

These results give a synopsis of the adequacy situations for Belgium for the next three winters. In the 'base case' scenarios there is no need for strategic reserve in order to fulfil the legal criteria. When correctly taking into account low-probability events with a high-impact on Belgian adequacy, a firm need for a strategic reserve volume is identified for winter 2018-19. This strategic reserve need is expected to shrink as of winter 2019-20.

Elia therefore recommends taking a decision on the basis of the scenarios incorporating low-probability events with a high-impact on Belgian adequacy. Concretely, this results in a need for 500 MW or 600 MW of strategic reserve depending on whether the Drogenbos power plant is operating in CCGT or OCGT mode for the entire winter.

With respect to the medium term (2025) and longer term (2030 and beyond) outlook, Elia would like to refer to its report 'Electricity Scenarios for Belgium towards 2050' published on 15 November 2017. In this report Elia analyses both short-term and long-term policy options for Belgium's future energy mix on the path towards 2050. Bearing in mind the planned nuclear phase-out in 2025, Elia is striving for a sustainable and adequate electricity system with prices that are competitive compared to our neighbouring countries.

In each future scenario for 2050 there is a need for additional adjustable (thermal) generation capacity in order to cope with the shock of the nuclear exit and guarantee security of supply. To guarantee an adequate electricity system, it is necessary - in all future scenarios - to build replacement capacity. Based on the assumptions in that study, in the event of a full nuclear exit by 2025, Belgium must develop at least 3.6 GW of new capacity that will come online by no later than winter 2025-2026. In calculating this 3.6 GW, Elia paid particular attention to energy efficiency, demand-side management, energy storage and the expected increase in renewable energy. It was also assumed that in 2025 there will be at least 2.3 GW of existing gas-fired power stations (both CCGT and OCGT).

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

- The calculated volume of strategic reserve does not differentiate between reductions in demand or production capacity. The volume is calculated on the assumption that this volume is for 100% available;
- The volume is calculated without taking into account the possibility of being able to actually find this volume 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 mentioned in this report. Elia cannot guarantee that these assumptions will actually materialise. In most cases, these are developments beyond the direct control or responsibility of the system operator.

EXECUTIVE SUMMARY

Zoals bepaald in de Elektriciteitswet, maakt Elia elk jaar op 15 november een probabilistische analyse over de bevoorradingszekerheid van België voor de volgende winter op. Deze analyse is een belangrijk element voor de beslissing van de federale minister van Energie over de nood aan een volume van strategische reserve. Deze beslissing dient ten laatste op 15 januari 2018 genomen te worden voor de winterperiode 2018-19.

Dit rapport geeft een probabilistische beoordeling van de Belgische bevoorradingszekerheid op basis van verschillende hypotheses en van de daarmee gepaard gaande behoefte aan strategische reserve voor de komende winterperiode 2018-19. Het geeft ook een eerste indicatie over de noodzaak voor de volgende winterperiodes 2019-20 en 2020-21.

Het 'basisscenario' zoals aangegeven in deze studie omvat de volgende veronderstellingen (alleen de belangrijkste elementen voor België zijn hieronder vermeld):

- een relatief beperkte groei van 0,5% per jaar van de totale vraag van België;
- de volledige beschikbaarheid van de nucleaire eenheden (normale ongeplande onbeschikbaarheden werden in rekening gebracht, met uitzondering van uitzonderlijke onbeschikbaarheden zoals die zich de afgelopen vijf winters hebben voorgedaan);
- Voorspellingen van zonne-energie en onshore windproductie op basis van de nieuwste gegevens van de regio's, in combinatie met de beste schatting van Elia en FOD Economie voor de offshore wind;
- Uitwisselingen tussen België en de andere CWE-landen worden gemodelleerd met behulp van historische Flow-Based-domeinen, die werden aangepast om rekening te houden met netinvesteringen in CWE tot winter 2018-19;
- een maximale gelijktijdige importcapaciteit van 4500 MW voor België voor winter 2018-19, die stijgt tot 5500 MW voor winters 2019-20 en 2020-21;
- de ingebruikname van de nieuwe interconnector met Groot-Brittannië (Nemo Link®) met een capaciteit van 1000 MW vanaf winter 2019-20;
- een stabiele evolutie van de rest van de thermische centrales in België tussen winter 2017-18 en winter 2018-19, met een kleine afname van het thermische vermogen voor zowel winter 2019-20 als winter 2020-21. Hypotheses voor de winter van 2018-19 zijn vast omdat eenheden hun sluiting ten laatste op 31 juli 2017 moesten aankondigen.

België blijft afhankelijk van import voor zijn elektriciteitsvoorziening. Daarom heeft elke verandering in de hypotheses van de buurlanden een potentiële impact op België en op het bijbehorende volume aan strategische reserve.

Omdat de geïnstalleerde capaciteit van de Belgische nucleaire eenheden zo groot is, heeft hun beschikbaarheid een zeer hoge impact op de Belgische bevoorradingszekerheid. Ongeplande onbeschikbaarheden die gebruikt worden in de berekeningen zijn gebaseerd op de historische ongeplande onbeschikbaarheden tijdens de afgelopen tien jaar. Uitzonderlijke langdurige ongeplande onbeschikbaarheden die zich voordeden op de Belgische kerncentrales tussen 2014 en 2017 zijn niet opgenomen in de percentages van het 'basisscenario' vanwege het uitzonderlijke karakter van deze onbeschikbaarheden. Gezien hun significante impact, is het echter belangrijk om een scenario te analyseren waarbij rekening wordt gehouden met dergelijke gebeurtenissen met een lage waarschijnlijkheid en hoge impact. Daarom is er een gedetailleerde vergelijking gemaakt van de gemodelleerde beschikbaarheid met de echte Belgische nucleaire beschikbaarheid gedurende de afgelopen vijf winters.

Als resultaat van deze analyse wordt vastgesteld dat gebeurtenissen met een lage waarschijnlijkheid met hoge impact, zoals waargenomen tijdens de laatste vijf winters, goed kunnen worden vastgelegd door een gevoeligheid te beschouwen met 1 GW aan nucleaire productiecapaciteit in België die gedurende de hele winter buiten dienst is.

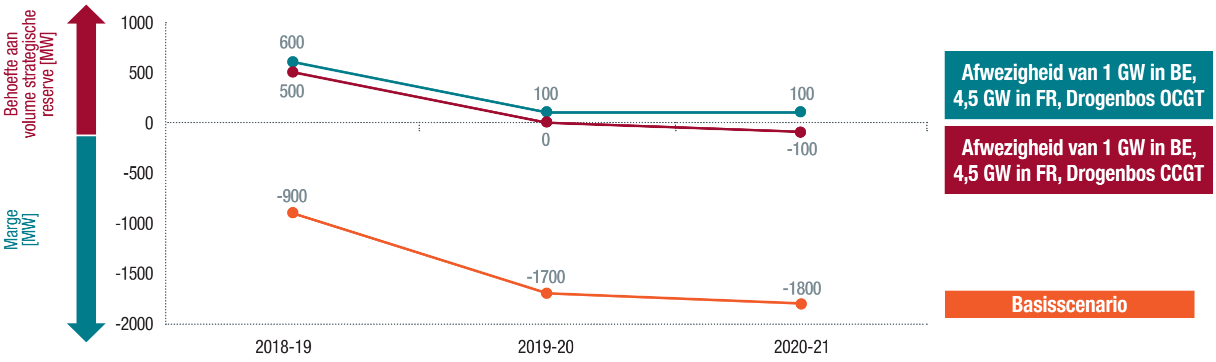
Ook onbeschikbaarheden in het Franse nucleaire productiepark hebben een impact op de bevoorradingszekerheid in België, zoals werd we dat de voorbije winter 2016-17 hebben gemerkt, toen meerdere nucleaire eenheden op verzoek van de Franse nucleaire veiligheidsautoriteit tijdelijk buiten dienst waren.

Bijgevolg is voor de Franse nucleaire beschikbaarheid dezelfde analyse uitgevoerd als voor de Belgische. Bij vergelijking van de gemodelleerde Franse nucleaire beschikbaarheid in het 'basisscenario' met de echte Franse nucleaire beschikbaarheid gedurende de laatste vijf winters, werd het duidelijk dat een gevoeligheid met 4,5 GW aan nucleaire productiecapaciteit in Frankrijk buiten dienst gedurende de hele winter zou moeten worden onderzocht.

Daarnaast houdt het 'basisscenario' rekening met de centrale Drogenbos als een OCGT[3]-productie-eenheid met een capaciteit van 230 MW. De productie-eenheid kan echter ook werken in een CCGT[4]-configuratie met een capaciteit van 460 MW. In de loop van de winter van 2016-17 werd waargenomen dat de eenheid haar normale operationele OCGT-modus veranderde in CCGT-modus. Zoals aangekondigd door de eigenaar van de centrale Drogenbos,

3. OCGT staat voor Open-Cycle Gas Turbine.
4. CCGT staat voor Combined Cycle Gas Turbine, ofwel STEG.

RESULTATEN VOOR HET 'BASISSCENARIO', EVENALS VOOR DE SENSITIVITEITEN OP DE BELGISCHE EN FRANSE NUCLEAIRE BESCHIKBAARHEID ZOWEL VOOR DROGENBOS ALS CCGT EN ALS OCGT



is dezelfde conversie gepland voor een deel van de winter 2017-18. Daarom werd de gevoeligheid voor de Belgische en Franse nucleaire beschikbaarheid ook gecombineerd met een gevoeligheid voor de werking van de Drogenbos-centrale als CCGT gedurende de hele winter.

Het 'basisscenario' in de studie leidt tot een marge van 900 MW, met een gemiddelde LOLE van 45 minuten en een LOLE95 gelijk aan 2 uur. **Onder de veronderstellingen die voor dit 'basisscenario' zijn gemaakt, geeft de analyse niet aan dat er een strategische reserve voor winter 2018-19 gecontracteerd moet worden om aan de wettelijke criteria te voldoen**.

Bij toepassing van de bovengenoemde gevoeligheidsanalyse voor het opvangen van gebeurtenissen met een lage waarschijnlijkheid en hoge impact, d.w.z. waarbij 1 GW nucleaire capaciteit niet beschikbaar is in België en 4,5 GW in Frankrijk gedurende de hele winter (bovenop de historisch gezien standaard ongeplande onbeschikbaarheden), en **waarbij de Drogenbos-eenheid in de OCGT-modus werkt, zou dit leiden tot een behoefte aan strategische reservevolume van 600 MW. Als de Drogenbos-eenheid de hele winter in de CCGT-modus werkt, bedraagt de geïdentificeerde behoefte 500 MW**.

Wat de winters 2019-20 en 2020-21 betreft, zal de marge op het systeem toenemen vooral dankzij de verwachte ingebruikname van de NEMO Link®-interconnector vanaf winter 2019-20.

Dit toont voor het 'basisscenario' een indicatieve verhoogde marge tot 1700 MW voor winter 2019-20 en 1800 MW voor winter 2020-21. Het LOLE-gemiddelde blijft voor beide winters onder de 1 uur. De LOLE P95 bereikt 2 uur in 2019-20 en 3 uur in 2020-21.

Dezelfde gevoeligheidsanalyse die is uitgevoerd voor de winter 2018-19, geeft voor de winters 2019-20 en 2020-21 een relatief kleine behoefte van 100 MW aan wanneer Drogenbos in OCGT-modus zou werken. Wanneer Drogenbos in CCGT-modus zou werken, wordt geen behoefte of marge geïdentificeerd voor winter 2019-20 en wordt een marge van 100 MW vastgesteld voor winter 2020-21.

Deze resultaten geven een overzicht van de bevoorradings-zekerheidssituaties voor België voor de komende drie winters. In de 'basisscenario's' is er geen strategische reserve nodig om te voldoen aan de wettelijke criteria. Wanneer op de juiste wijze rekening wordt gehouden met gebeurtenissen met een lage waarschijnlijkheid die een hoge impact hebben op de Belgische bevoorradingszekerheid, wordt voor winter 2018-19 een sterke behoefte aan een volume strategische reserve geïdentificeerd. Deze behoefte aan strategische reserve zal naar verwachting vanaf de winter van 2019-20 aanzienlijk afnemen.

Daarom beveelt Elia aan om een beslissing te nemen op basis van de scenario's met gebeurtenissen met een lage waarschijnlijkheid die een hoge impact hebben op de Belgische bevoorradingszekerheid. Concreet resulteert dit in een behoefte aan strategische reserve van 500 MW of 600 MW, afhankelijk van de werking van de Drogenbos-centrale als CCGT, respectievelijk OCGT voor de hele winter.

Wat de vooruitzichten betreft op middellange (2025) en langere termijn (2030 en daarna), zou Elia willen verwijzen naar het rapport 'Electricity Scenarios for Belgium towards 2050', gepubliceerd op 15 november 2017. In dit rapport analyseert Elia beleidsopties zowel op korte als lange termijn voor de toekomstige energiemix voor België op weg naar 2050. Rekening houdend met de geplande nucleaire uitstap in 2025, streeft Elia naar een duurzaam en adequaat elektriciteitssysteem met prijzen die competitief zijn in vergelijking met onze buurlanden.

In elk toekomstscenario voor 2050 is er behoefte aan bijkomende regelbare (thermische) productiecapaciteit om de schok van de nucleaire uitstap op te vangen en de bevoorradingszekerheid te garanderen. Om een adequaat elektriciteitssysteem te garanderen, is het in alle toekomstscenario's noodzakelijk om vervangingscapaciteit te bouwen. Op basis van de veronderstellingen in de studie, in het geval van een volledige nucleaire exit in 2025, moet België tenminste 3,6 GW aan nieuwe capaciteit bouwen die uiterlijk tegen 2025-2026 operationeel zal zijn. Bij de berekening van deze 3,6 GW heeft Elia bijzondere aandacht besteed aan energie-efficiëntie, beheer van de vraagzijde, energieopslag en de verwachte toename van hernieuwbare energie. Er werd ook aangenomen dat er in 2025 minstens 2,3 GW aan bestaande gasgestookte elektriciteitscentrales zal zijn (zowel CCGT als OCGT).

Tot slot moeten, bij het interpreteren van de resultaten, volgende belangrijke veronderstellingen in aanmerking worden genomen:

- Bij de berekening van de strategische reserve wordt er geen onderscheid gemaakt tussen vraagbeperking of productiecapaciteit. Het volume wordt berekend in de veronderstelling dat dit volume 100% beschikbaar is;
- De berekening van het volume wordt gemaakt zonder rekening te houden met de mogelijkheid om de benodigde hoeveelheid effectief in België te kunnen vinden;
- De marge of het tekort (nood aan strategische reserve volume) wordt berekend om beide wettelijke criteria (LOLE gemiddeld en LOLE P95) te vervullen.

Elia wenst te benadrukken dat de conclusies van dit rapport onlosmakelijk zijn verbonden met de veronderstellingen die erin aan bod komen. Elia kan niet garanderen dat deze veronderstellingen worden gerealiseerd. In de meeste gevallen gaat het om ontwikkelingen die buiten de directe controle en de verantwoordelijkheid van de netbeheerder liggen.

EXECUTIVE SUMMARY

Comme prévu dans la loi Électricité, Elia doit livrer, le 15 novembre de chaque année, une analyse probabiliste sur l'adéquation pour l'hiver suivant. Cette analyse est un élément important à prendre en compte par le ministre fédéral de l'Énergie pour prendre une décision sur le volume nécessaire de réserve stratégique. La date limite pour cette décision pour l'hiver 2018-19 est le 15 janvier 2018.

Ce rapport fournit une évaluation probabiliste de la sécurité de l'approvisionnement de la Belgique suivant plusieurs hypothèses ainsi que le besoin correspondant de réserve stratégique pour la prochaine période hivernale 2018 19. Il donne également une première estimation du besoin pour les périodes hivernales suivantes 2019 20 et 2020 21.

Le 'scénario de base' indiqué dans cette étude comprend les hypothèses suivantes (seuls les facteurs clés pour la Belgique sont énumérés ci-dessous):

- une croissance relativement limitée de 0,5% par an de la demande totale de la Belgique;
- la disponibilité totale des unités nucléaires (les taux d'indisponibilité fortuite normaux ont été pris en compte, sans tenir compte des pannes exceptionnelles survenues au cours des 5 derniers hivers);
- des prévisions de la production photovoltaïque et éolienne onshore basées sur les dernières données des régions, combinées à la meilleure estimation d'Elia et du SPF Economie pour l'éolien offshore;
- les échanges entre la Belgique et les autres pays de la région CWE sont modélisés à l'aide de domaines flow-based historiques, modifiés pour prendre en compte les investissements dans les réseaux de la région CWE jusqu'à l'hiver 2018-2019;
- une capacité d'importation simultanée maximale de 4500 MW pour la Belgique pour l'hiver 2018-19, qui augmente à 5500 MW pour les hivers 2019-20 et 2020-21;
- la mise en service de la nouvelle interconnexion avec la Grande-Bretagne (Nemo Link®) d'une capacité de 1000 MW à partir de l'hiver 2019-20;
- une évolution stable du reste du parc de production thermique en Belgique entre l'hiver 2017-18 et l'hiver 2018-19, et une légère diminution de la capacité thermique à la fois pour l'hiver 2019-20 et l'hiver 2020-21. Les hypothèses pour l'hiver 2018-2019 sont fixes puisque les unités devaient annoncer leur fermeture au plus tard le 31 juillet 2017.

La Belgique reste dépendante des importations pour son approvisionnement en électricité. Par conséquent, toute modification des hypothèses dans les pays voisins a un impact potentiel sur la Belgique et sur le volume correspondant de réserve stratégique.

En raison de la grande capacité installée des unités nucléaires belges, leur disponibilité a un impact très significatif sur la sécurité d'approvisionnement de la Belgique. Les taux d'indisponibilité fortuite utilisés dans les calculs sont basés sur l'indisponibilité non planifiée historique des dix dernières années. Les pannes exceptionnelles de longue durée qui ont touché les centrales nucléaires belges entre 2014 et 2017 n'ont pas été incluses dans les taux d'indisponibilité fortuite du 'scénario de base' en raison du caractère exceptionnel de ces indisponibilités. Compte tenu de leur impact significatif, il est toutefois important d'analyser un scénario prenant en compte des événements de faible probabilité et à fort impact. Par conséquent, une comparaison détaillée entre la disponibilité modélisée et la disponibilité réelle du parc nucléaire belge ces cinq derniers hivers a été effectuée.

À la suite de cette analyse, nous avons conclu que les événements de faible probabilité ayant un impact élevé, observés au cours des 5 derniers hivers, peuvent être correctement intégrés en considérant une sensibilité de 1 GW de capacité de production nucléaire hors service pour tout l'hiver en Belgique.

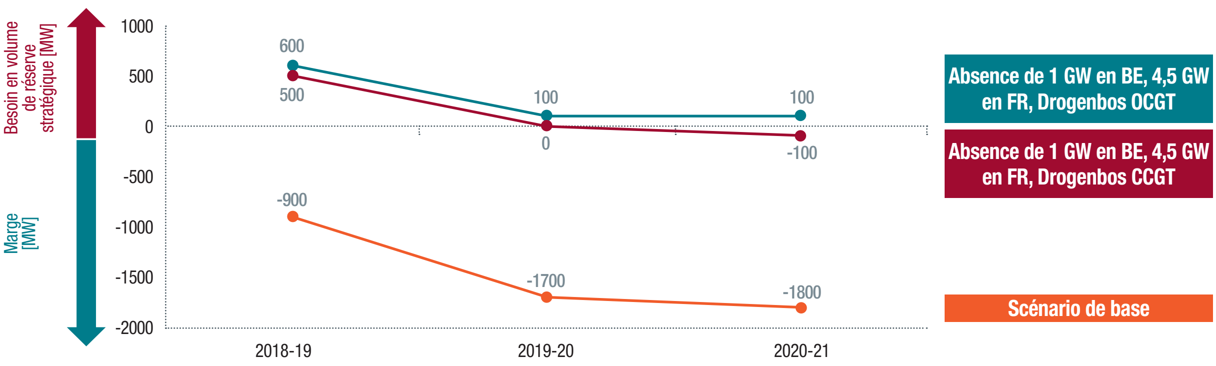
Les indisponibilités du parc nucléaire français ont également un impact sur la sécurité d'approvisionnement en Belgique, comme on l'a vu lors de l'hiver 2016-17 où de nombreuses unités nucléaires ont été temporairement mises hors service à la demande de l'Autorité de Sûreté Nucléaire française.

Par conséquent, la même analyse que pour la Belgique a été réalisée pour la disponibilité nucléaire française. En comparant la disponibilité nucléaire française modélisée dans le 'scénario de base' à la disponibilité nucléaire française réelle au cours des cinq derniers hivers, il est apparu qu'une sensibilité de 4,5 GW de capacité de production nucléaire hors service en France pour tout l'hiver devait être étudiée.

De plus, le 'scénario de base' prend en compte la centrale de Drogenbos en tant qu'unité de production OCGT[5] d'une capacité de 230 MW. Cependant, l'unité de production peut également fonctionner dans une configuration CCGT[6] d'une capacité de 460 MW. Au cours de l'hiver 2016-2017, il a été observé que l'unité avait changé son mode opérationnel normal d'OCGT en CCGT. Comme annoncé par le propriétaire de la centrale de Drogenbos, la même conversion est prévue pour une partie de l'hiver 2017-18.

5. Open-Cycle Gas Turbine.
6. Combined Cycle Gas Turbine.

RÉSULTATS DU 'SCÉNARIO DE BASE', AINSI QUE POUR LES SENSITIVITÉS SUR LA DISPONIBILITÉ DES UNITÉS NUCLÉAIRE BELGES ET FRANÇAISES POUR DROGENBOS EN MODE D'OPÉRATION CCGT ET OCGT



Par conséquent, la sensibilité sur la disponibilité nucléaire belge et française a été combinée avec une sensibilité sur l'exploitation de la centrale de Drogenbos en tant que CCGT pour tout l'hiver.

Le 'scénario de base' de l'étude conduit à une marge de 900 MW, avec un LOLE moyen de 45 minutes et un LOLE95 égal à 2 heures. **Selon les hypothèses retenues pour ce 'scénario de base', l'analyse n'indique pas la nécessité de contracter une réserve stratégique pour l'hiver 2018-2019 afin de satisfaire aux critères juridiques**.

En appliquant l'analyse de sensibilité mentionnée ci-dessus pour intégrer les événements à faible probabilité et à fort impact, c'est-à-dire où une capacité nucléaire de 1 GW serait indisponible en Belgique et 4,5 GW en France pendant tout l'hiver (en plus des taux d'indisponibilité fortuite normaux historiques), et où l'unité de Drogenbos fonctionne en mode OCGT, **cela entraînerait un besoin de volume de réserve stratégique de 600 MW. Dans le cas où l'unité Drogenbos fonctionne en mode CCGT pendant tout l'hiver, le besoin identifié est de 500 MW**.

Pour les hivers 2019-20 et 2020-21, le système bénéficiera d'une plus grande marge, principalement grâce à la mise en service attendue de l'interconnecteur NEMO Link® d'ici l'hiver 2019-2020.

Le 'scénario de base' indique une marge accrue allant jusqu'à 1700 MW pour l'hiver 2019-2020 et 1800 MW pour l'hiver 2020-21. La moyenne de LOLE reste inférieure à 1 heure pour les deux hivers. Le LOLE P95 atteint 2 heures en 2019-20 et 3 heures en 2020-21.

La même analyse de sensibilité qui a été réalisée pour l'hiver 2018-2019 indique, pour les hivers 2019-20 et 2020-21, un besoin relativement faible de 100 MW lorsque Drogenbos fonctionnerait en mode OCGT. Lorsque Drogenbos fonctionne en mode CCGT, aucun besoin ou marge n'est identifié pour l'hiver 2019-20 et une marge de 100 MW est identifiée pour l'hiver 2020-21.

Ces résultats donnent une vue d'ensemble des situations d'adéquation de la Belgique pour les trois prochains hivers. Dans les 'scénarios de base', il n'y a pas besoin de réserve stratégique pour remplir les critères légaux. Si l'on prend correctement en compte les événements à faible probabilité ayant un impact important sur l'adéquation belge, un besoin ferme d'un volume de réserve stratégique est identifié pour l'hiver 2018-2019. Ce besoin de réserve stratégique devrait diminuer dès l'hiver 2019-2020.

Par conséquent, Elia recommande de prendre une décision sur base des scénarios intégrant des événements à faible probabilité ayant un impact important sur l'adéquation belge. Concrètement, il en résulte un besoin de réserve stratégique de 500 MW ou de 600 MW si la centrale de Drogenbos est exploitée en mode CCGT ou en mode OCGT pour l'ensemble de l'hiver.

En ce qui concerne les perspectives à moyen terme (2025) et à plus long terme (2030 et au-delà), Elia voudrait faire référence à son rapport 'Electricity Scenarios for Belgium towards 2050' publié le 15 novembre 2017. Dans ce rapport, Elia analyse des options politiques à court et à long terme pour le futur mix énergétique de la Belgique d'ici 2050. Tout en tenant compte de la sortie du nucléaire prévue pour 2025, Elia vise un système électrique belge durable et adéquat aux prix compétitifs par rapport à nos pays voisins.

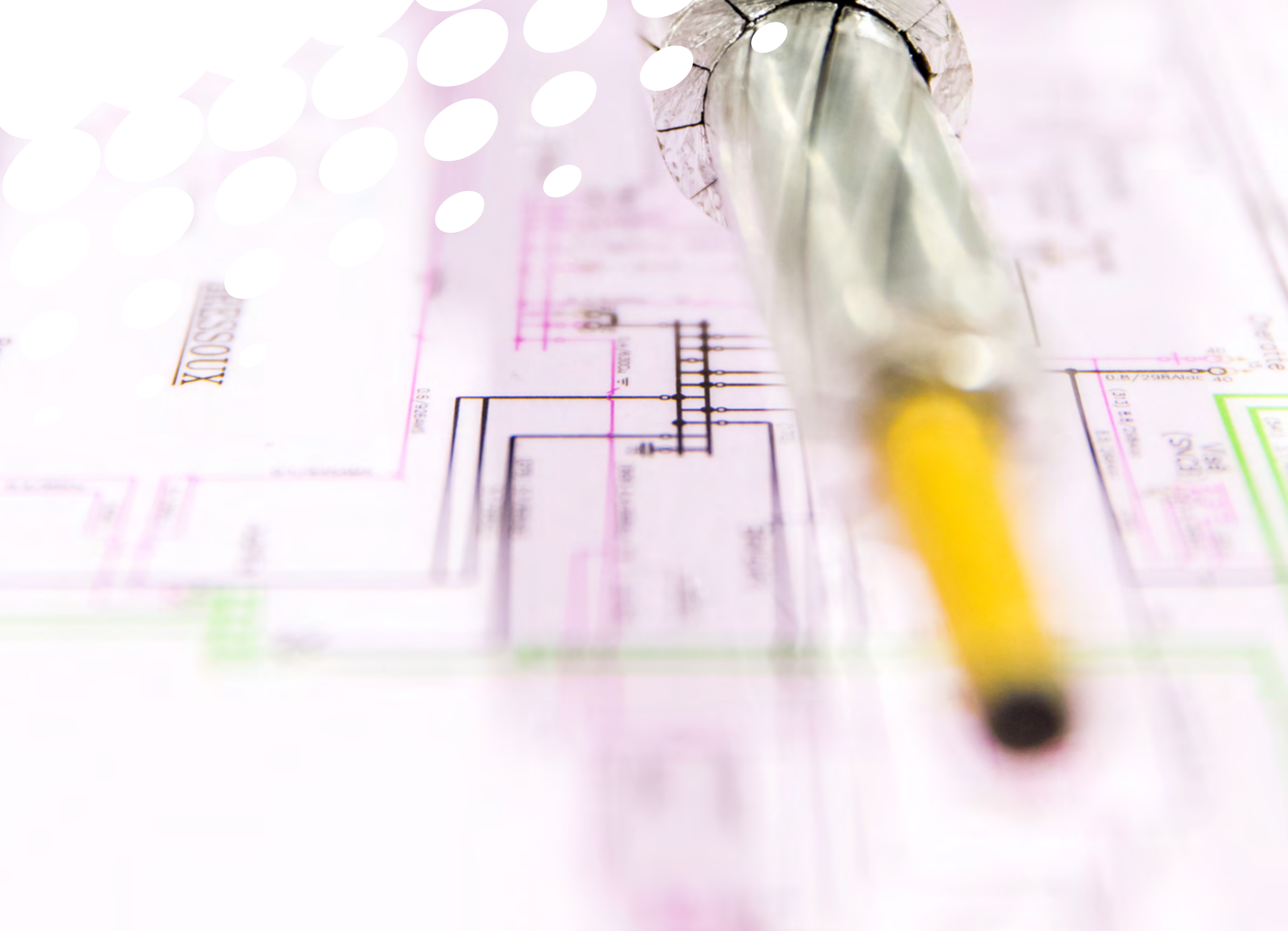
Dans chaque scénario futur pour 2050, il est nécessaire de disposer d'une capacité de production (thermique) réglage supplémentaire afin de faire face au choc de la sortie du nucléaire et de garantir la sécurité de l'approvisionnement. Pour garantir un système d'électricité adéquat, il est nécessaire – dans tous les scénarios futurs – de construire une capacité de remplacement. Sur la base des hypothèses de cette étude, en cas de sortie nucléaire complète d'ici 2025, la Belgique doit développer au moins 3,6 GW de nouvelle capacité qui devra être mise en service au plus tard pour hiver 2025-2026. En calculant ces 3,6 GW, Elia a accordé une attention particulière à l'efficacité énergétique, à la gestion de la demande, au stockage de l'énergie et à l'augmentation attendue des énergies renouvelables. Il a également été supposé qu'en 2025, il y aura au moins 2,3 GW de centrales électriques au gaz existantes (à la fois CCGT et OCGT).

Enfin, lors de l'interprétation des résultats, les hypothèses clés suivantes doivent être prises en compte :

- le volume de réserve stratégique calculé ne fait pas de distinction entre les réductions de la demande ou de la capacité de production. Le volume est calculé en supposant que ce volume est disponible à 100%;
- le calcul du volume est effectué sans tenir compte de la possibilité de pouvoir effectivement trouver ce volume en Belgique;
- la marge ou le déficit (besoin en réserve stratégique) est calculé de manière à répondre aux deux critères légaux (LOLE moyen et LOLE P95).

Elia souhaite souligner que les conclusions de ce rapport sont inséparables des hypothèses qui sont mentionnées dans ce rapport. Elia ne peut garantir que ces hypothèses se réaliseront. Il s'agit dans la plupart des cas d'évolutions indépendantes du contrôle direct et de la responsabilité du gestionnaire de réseau de transport.

01 INTRODUCTION



A strategic reserve mechanism has been in place since 2014 to strengthen the electricity security of supply of Belgium during the winter period. This mechanism entails new tasks and responsibilities for Elia System Operator (hereinafter 'Elia'). One of these is to determine the need for the strategic reserve by means of a probabilistic assessment. This report sets out the assessment for the winter period 2018-2019 that Elia is required to conduct by 15 November 2017.

Elia has already carried out previous assessments for the winters of 2014-15, 2015-16, 2016-17 and 2017-18. These documents are publicly available on the website of the Directorate-General for Energy at FPS Economy.[7]

The current report continues to build upon the major elaboration and expansion introduced in previous years. As such, the same general structure is applied. In contrast with previous reports, some modelling details have been moved to an appendix to make the study more easily readable.

Chapter 1 presents the relevant background and context (incl. a status of the EU-investigation), gives 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 used and the framework for the probabilistic assessment. The application of this is covered in 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 the situation in neighbouring countries.

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

Chapters 6 sets out the results of the assessment for the winters 2018-19, 2019-20 and 2020-21. A more in-depth analysis of the 'base case' scenario for winter 2018-19 is given and explained in detail. In addition to the results for the 'base case' scenario, detailed results for a sensitivity scenario on nuclear availability in Belgium and France, combined with the operation of the Drogenbos power plant in CCGT mode, are given.

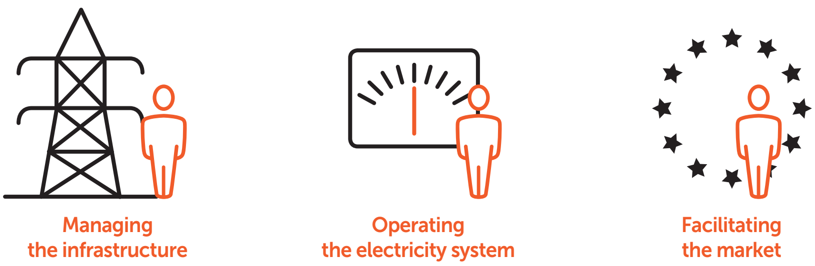
The study ends with Chapter 7, setting out the conclusions of this report. Chapter 8 contains the aforementioned appendix with modelling details.

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

ROLES AND RESPONSIBILITIES

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

MAIN ACTIVITIES OF ELIA (FIG. 2)



7. http://economie.fgov.be/nl/consument/Energie/Energiebevoorradingszekerheid/strategische_reserve_elektriciteit/#.WcuKC2cUnIU

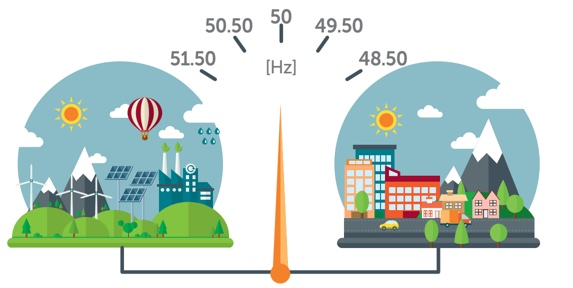
ELIA'S THREE CORE ACTIVITIES ARE:

OPERATING THE ELECTRICITY SYSTEM

This task is facing increasing challenges. Accordingly, sophisticated tools and processes and special skills are needed to maintain balance on the system 24 hours a day, all year round. As electrical energy cannot be stored in high volumes, balance must be maintained in real time with a view to ensure a reliable supply and the efficient operational management of the high-voltage grid. The 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.



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 power plants and centres of consumption have increased significantly, 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 expanding both the distribution and transmission grids. Elia adopts innovative technologies to boost the efficiency and reliability of its electricity system, and manages its infrastructure in a cost-efficient way, with an unremitting focus on safety.

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:

- **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;
- **Balance Responsible Parties** (BRPs[8]) ensure quarter-hourly balance between all their customers' injections and offtakes;
- **Distribution System Operators** (DSOs) manage the distribution grids and, as such, pass on the electricity to the businesses and private individuals connected to their grid;
- the **federal government** determines general policy, including policy on the security of the energy supply;
- the **federal regulator CREG**[9] 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 enforcement of the relevant legislation and regulations.

8. This may be a generator, a major consumer, an electricity supplier or a trader, among others.
9. CREG: Commission for Electricity and Gas Regulation.

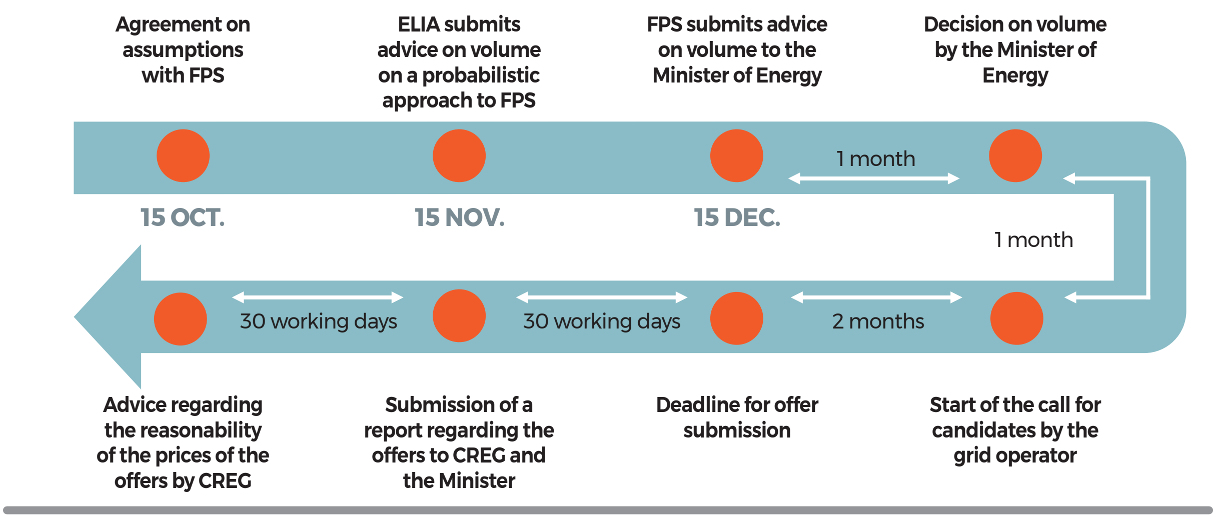
1.2 LEGAL FRAMEWORK AND PROCESS[10]

Article 7bis to 7sexies of the Law of 29 April 1999 on the organisation of the electricity market ('Electricity Act') includes the following **timetable** for determining the volume of the strategic reserve (see also Figure 4):

ART.7 BIS – 7 SEXIES

- ***Prior to 15 October***: *DG Energy[11] 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.*
- ***One month after the Minister's instruction***: *The grid operator starts the procedure for constituting strategic reserve. Offers should be submitted within two months after the start of this procedure.*
- ***30 working days after the latest submission date of offers***: *The grid operator submits a report to CREG and the Minister regarding all received offers and proposes a technico-economic optimal selection of offers.*
- ***30 working days after receipt of the grid operators report:*** *CREG issues an advice that explicitly and in a motivated way indicates whether or not the price of the proposed selection of offers by the grid operator is manifestly unreasonable. If the CREG's advice indicates that the offers that are part of the technico-economic selection are not unreasonable, the grid operator concludes contracts for these offers. In the CREG's advice concludes that the selection made by the grid operator is manifestly unreasonable, the King may, further to a proposal by the Minister and, for reasons of security of supply, impose by Royal Decree the necessary prices and volumes on one or more suppliers whose offer was considered by CREG as manifestly unreasonable.*

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

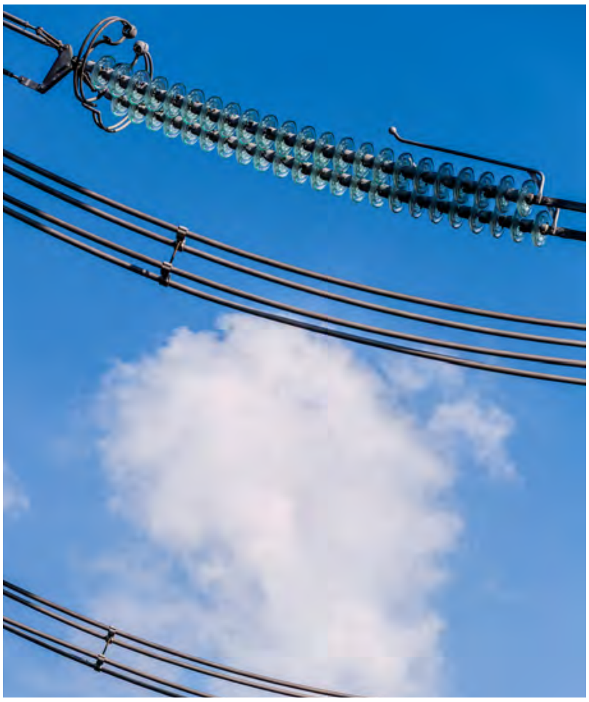


10. Some texts in this section are taken from the Electricity Act and are not available in English (only in French and Dutch). They are translated from those languages for the reader's information. Elia assumes no responsibility for the accuracy of the translation of these legal articles and, in case of any doubt, the original text prevails over these translations. This also applies to other translations from the Electricity Act provided in this report.
11. Directorate-General for Energy at Federal Public Service (FPS) Economy.

This law also includes the following aspects that must be borne in mind for the probabilistic assessment regarding the security of Belgium's supply for the winter ahead:

ART.7 BIS §4

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



EUROPEAN INVESTIGATION ON THE COMPATIBILITY OF THE BELGIAN STRATEGIC RESERVE WITH THE APPLICABLE EU STATE AID RULES

As of the summer of 2017, the Belgian and European authorities have been in contact to investigate if the Belgian mechanism of strategic reserve is compatible with the applicable EU State aid rules, and in particular with the 'Guidelines on State aid for environmental protection and energy 2014 - 2020' (EEAG).

Even though there is not yet a final, public decision of the European authorities, Elia and CREG have shortly before the final delivery of this probabilistic assessment report, i.e. on 10 November 2017, been formally informed of the commitments that the Federal Minister of Energy has taken towards the European Commission. The commitments for the future concern mainly:

- That strategic reserve capacities cannot accumulate any revenues from in-the-market frequency ancillary services (with an exception for the black-start service, for which plants participating in the strategic reserve can perform the service as a last resort measure);
- That the next adequacy assessments should include a 'low-probability high-impact' scenario;
- That an approval of the strategic reserve is requested for no longer than five years;
- To amend the relevant legal basis of the measure (Electricity Law) in order to ensure that:
  - The volume can be adjusted upwards and downwards in the period between the definition of the strategic reserve size by the Minister and the eventual contracting of capacities by the TSO;
  - When the tender does not put forward competitive bids, prices are reduced by the Ministry on the basis of the recommendation of the Regulator;
  - A prohibition is foreseen for capacities to return to the market (no-return clause) during the term of their reserve contracts;
  - A prohibition is foreseen for power plants that announced 'definitive closure' to return to the market at any point in time thereafter.
- To align the duration of reserve contracts with the frequency and time horizon of (annual) adequacy assessments, i.e. only 1 year contracts;
- To increase the specific imbalance penalty in case of structural shortage following an economic or technical trigger (currently at 4500 €/MWh) to above the Intraday (ID) price cap (of 9999 €/MWh) to limit market distortions.

Without prejudice to the timely implementation or the exact formulation of these commitments, Elia informs the market actors of these topics which are expected to lead to modifications in the following weeks and months. This adequacy report of November 2017 for winter 2018-19 is however based on the current legal framework and has not taken these elements into account. In any case, this report already foresaw the inclusion of a low-probability, high-impact scenario.

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[12]': 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[13], 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[14].*

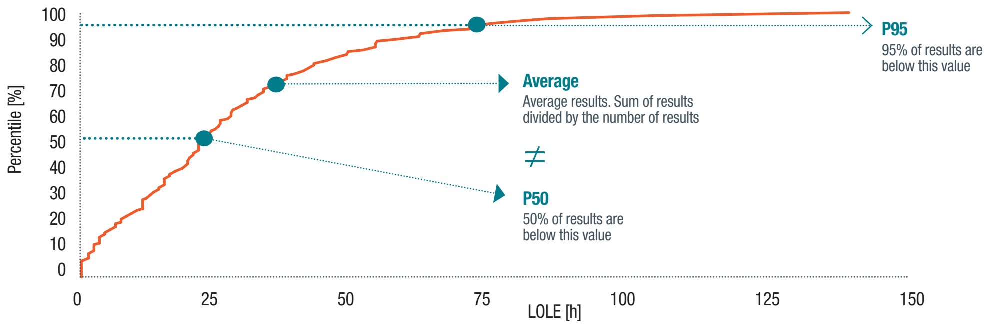
HOW TO INTERPRET THE ADEQUACY CRITERIA

The following indicative figure (Figure 6) shows how to interpret the adequacy criteria. Many future states are calculated for a given winter in a probabilistic assessment (see section 8.1). For each future state, the model calculates the LOLE for the winter. The distribution of the LOLE among all studied future states can be extracted.

For the first criterion, the average is calculated from all these LOLE results[15]. For the second criterion (95th percentile), all the LOLE results are ranked. The highest value, after the top 5% of values have been disregarded, gives the 95th percentile (1 chance in 20 of having this amount of LOLE). **Both criteria need to be satisfied for Belgium**, as specified in the Electricity Act.

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

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



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

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. LOLE: Loss Of Load Expectation.
13. Load: demand for electricity.
14. The probability of occurrence of a statistically abnormal year is 1 in 20 (95th percentile).
15. 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.

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**'[16]: the volume of energy that cannot be supplied during the hours in which loss of load occurs. This yields ENS (for a statistically normal year) and ENS95 (for a statistically abnormal year), expressed in GWh per year.
- '**LOLP**'[17]: the probability that at a given time a loss of load situation will occur, expressed in %.

In 2014, CEER[18] 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 its conclusions 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 on the assumption of 100% availability in order to fulfil both legal criteria in terms of security of supply. No distinction is made between demand reduction (SDR[19]) and generation capacity (SGR[20]):

- 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 8.1.1).
- 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 duration of activations.

The assumption of 100% availability of the SGR is important, 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 equally important, as restrictions on the number and the duration of activations could be included in the operating modalities.

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

16. ENS: Energy Not Served.
17. LOLP: Loss Of Load Probability.
18. CEER: Council of European Energy Regulators.
19. SDR: Strategic Demand Reserve.
20. SGR: Strategic Generation Reserve.

GENERAL BACKGROUND ON STRATEGIC RESERVE

1.4.1. HOW IS A RISK TO SECURITY OF SUPPLY IDENTIFIED OPERATIONALLY?

The potential security of supply risk 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 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 [5] to the general public (see Figure 8).

At the same time, when a structural shortage[21] is identified, this may lead to the activation of the strategic reserve. Notification of any such activation is published on Elia's website [6]. 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 [7].

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

POWER INDICATOR: 7-DAY FORECAST (FIG. 8)

Green	Orange	Red	Black
There is enough electricity to cover consumption – no need to worry!	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!	There is not enough electricity to meet our needs at all time. The authorities have decided to take prohibitive measures to cut consumption further.	If not possible otherwise, some consumers will temporarily have their power cut to prevent a widespread, uncontrolled, long-term blackout.

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 for avoiding any interruption in the power supply.

21. A structural shortage as defined in the rules governing the functioning of the strategic reserve [7] 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.

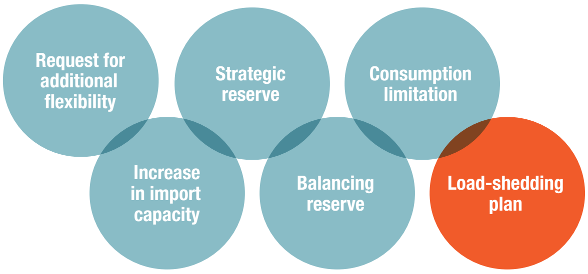
1.4.3. WHAT MEASURES WILL BE TAKEN IF A RISK TO SECURITY OF SUPPLY MATERIALISES?

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 9):

- 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 RSS[22] feed to send out a balancing warning on the web [8].
- If the situation so requires, Elia will assess whether special measures are possible in coordination and collaboration with the other transmission system operators in the CWE area[23] to further increase Belgium's **import capacity**.
- An economic or technical trigger may give rise to activation of Belgium's **strategic reserve**.
- 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[24], reducing the consumption of industrial customers and requesting assistance from neighbouring transmission system operators.
- 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.

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

MEASURES IF A SHORTAGE OCCURS (FIG. 9)



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

The load-shedding plan is a measure of last resort that can be used if all 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 year. 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, duration of the intervention and communications at the time of the outage) can be found on the FPS Economy website [9].

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, 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 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 works on the distribution grid.

The **legal framework** for the load-shedding plan is set out in 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.

22. RSS: Really Simple Syndication.
23. CWE: Central West Europe.
24. An aggregator is a demand service provider that combines multiple short-duration consumer loads for sale or auction in organised energy markets.

1.5 HISTORY AND CURRENT SITUATION OF STRATEGIC RESERVE CONSTITUTION

Since the introduction of the strategic reserve in winter 2014-15, there has been a strategic reserve volume for each winter period (see Figure 10). More specifically, the strategic reserve for **winter 2014-15** comprised:

– 750 MW of generation capacity, for three years;

– 96.7 MW of load-shedding capacity, for one year.

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

– 750 MW of generation capacity, since 2014;

– 427.1 MW of additional generation capacity, for one year;

– 358.4 MW of load-shedding capacity, for one year.

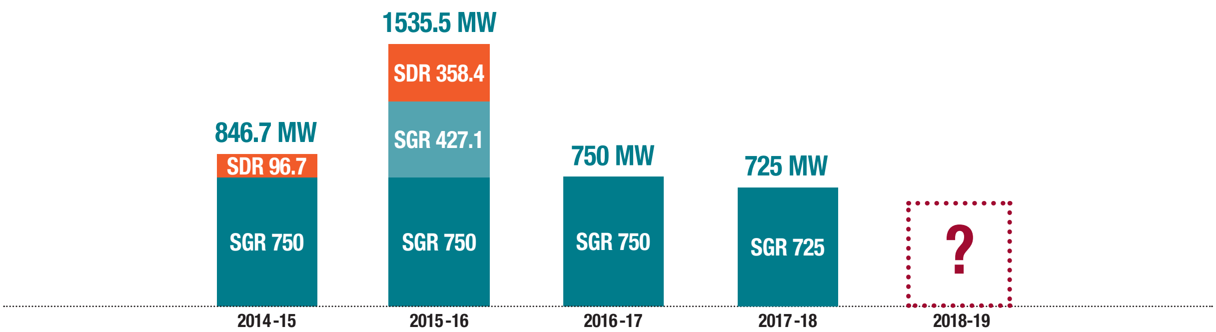
For **winter 2016-17**, no additional volume was acquired. However, there was still 750 MW of generation capacity retained (three-year period as of 2014). Therefore, on 1 November 2016, the following capacity was comprised in the strategic reserve:

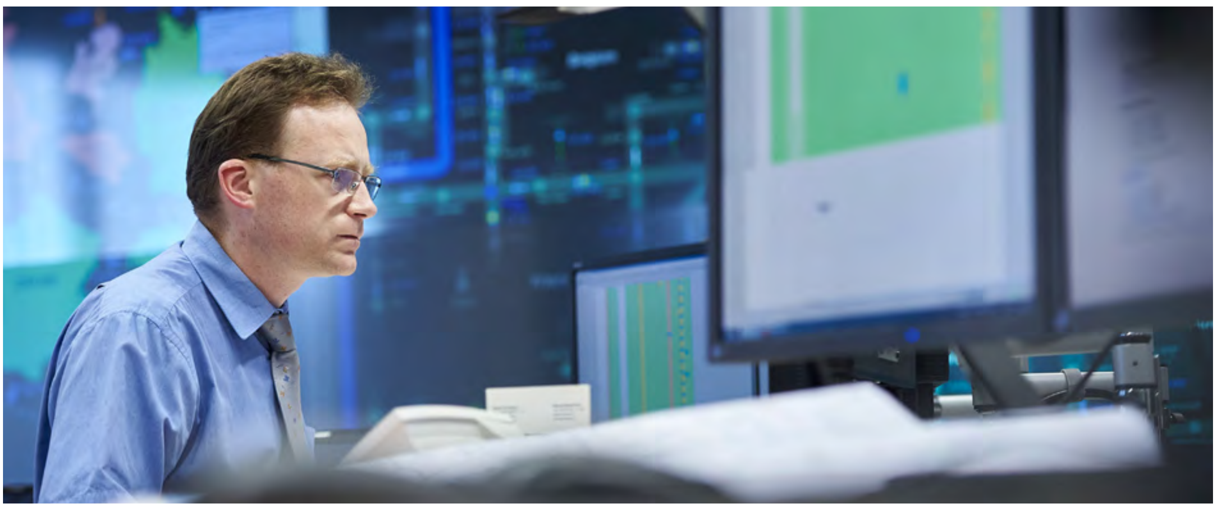
– 750 MW of generation capacity, since 2014;

For **winter 2017-18**, no capacity was previously contracted. On 1 November 2017, the following capacity was comprised in the strategic reserve:

– 725 MW of generation capacity, for one year.

STRATEGIC RESERVE VOLUME FOR WINTERS 2014-15 TO 2017-18 (FIG. 10)



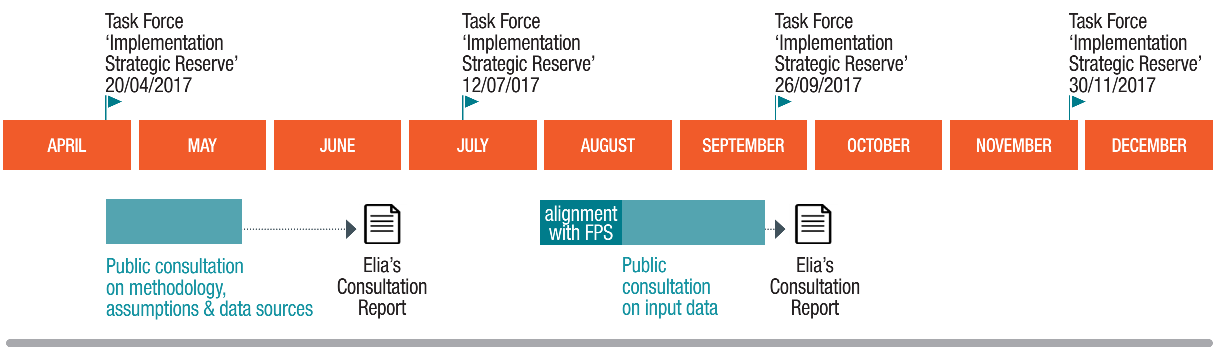


PUBLIC CONSULTATIONS REGARDING STRATEGIC RESERVE VOLUME CALCULATIONS

The potential problems Belgium could face 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 2017: 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 2017 (FIG. 11)



The consultations were announced in the meetings of the Task Force 'implementation Strategic Reserve' respectively on 20 April 2017 for the first consultation and on 12 July 2017 for the second consultation.

Both consultations were announced on Elia's homepage and each time all involved stakeholders (members of the Task Force 'implementation Strategic Reserve', the contractual contact points known at the customer relations department and the regulator CREG) were informed through e-mails.

1.6.1. FEEDBACK FROM STAKEHOLDERS

Following the two consultations, Elia received respectively two and five (one of which was 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 [56] and [57]. The answers were orally explained at the Task Force 'Implementation Strategic Reserve' meeting on 12 July 2017 for the first consultation and on 26 September 2017 for the second consultation.

FEEDBACK FROM STAKEHOLDERS ON PUBLIC CONSULTATIONS IN 2017 (FIG. 12)

PUBLIC CONSULTATION 1

- **Content**: methodology, assumptions, data sources
- **Consultation Period**: 24 April to 22 May 2017 at 18:00
- **Responses received**: 2
- **Subjects**: Market response, Flow-Based Modelling, Data, Assumptions, Volume Determination, Process
- **Consulted document and Consultation Report**: [56]

PUBLIC CONSULTATION 2

- **Content**: raw input data
- **Consultation Period**: 21 August to 18 September 2017 at 18:00
- **Responses received**: 5 (of which 1 was confidential)
- **Subjects**: General, Data, Market Response, Flow-Based Domains
- **Consulted document and Consultation Report**: [57]

1.6.2. FOLLOW-UP TO THE CONSULTATION

Elia examined the various suggestions and different actions were taken to update the data.

Some received responses requested only additional clarifications of the principles used which consequently will be further clarified in this volume report for winter 2018-19.

Remarks on the market response methodology and data were taken into account in the 'demand response subgroup' as described in section 3.3.

The methodological improvements in comparison to previous years are explained in more detail in section 1.7 below. 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.

METHODOLOGY AND MODELLING IMPROVEMENTS FROM THE PREVIOUS ASSESSMENT

Following the public consultation on methodology, hypotheses and data sources, several improvements in the modelling were implemented for this assessment. Below we include an overview of the new methodological improvements that were considered in the assessment for winter 2018-2019, compared to the assessment performed for winter 2017-18:

HVDC[25] outage modelling

Simulated random forced outages of HVDCs are incorporated in the modelling in addition to forced outages of thermal units. This new methodological improvement is considered in order to incorporate in all the simulations the impact of the availability of HVDC lines on system adequacy (see section 5.2.2). This improvement is in line with developments performed in the ENTSO-E MAF 2017 study [16].

Flow-Based modelling

A revision of the selection process and number of typical days and their corresponding flow-based domains from the flow-based operational environment is considered. Data comprising observations of the previous two winters (2015-16 and 2016-17) were analysed for this purpose. Also a special focus is on ensuring consistency with ongoing national and regional adequacy assessments including flow-based methods (see section 5.1 for more details).

A new way of correlating the flow-based domains with climatic data is taken into account. Last year, three typical domains were considered and their correlation to hourly situations was driven only by the level of wind infeed in Germany. This year a more systematic approach is taken, linking specific combinations of climate conditions of wind and demand with the representative flow-based domains to be considered in the simulations (see section 5.1).

Climatic Database

A new climatic database of wind, PV and temperature time series procured within the framework of ENTSO-E was used to align and ensure consistency with ongoing regional and pan-European adequacy assessments as well as relevant national adequacy studies.

Thermal Sensitivity of Load

A new way of incorporating the temperature sensitivity of the load has been used. Instead of a linear relationship between temperature and load, a cubic relationship is used, making it possible to systematically capture effects like saturation, while preserving the level of accuracy of the linear method previously used.

Market Response

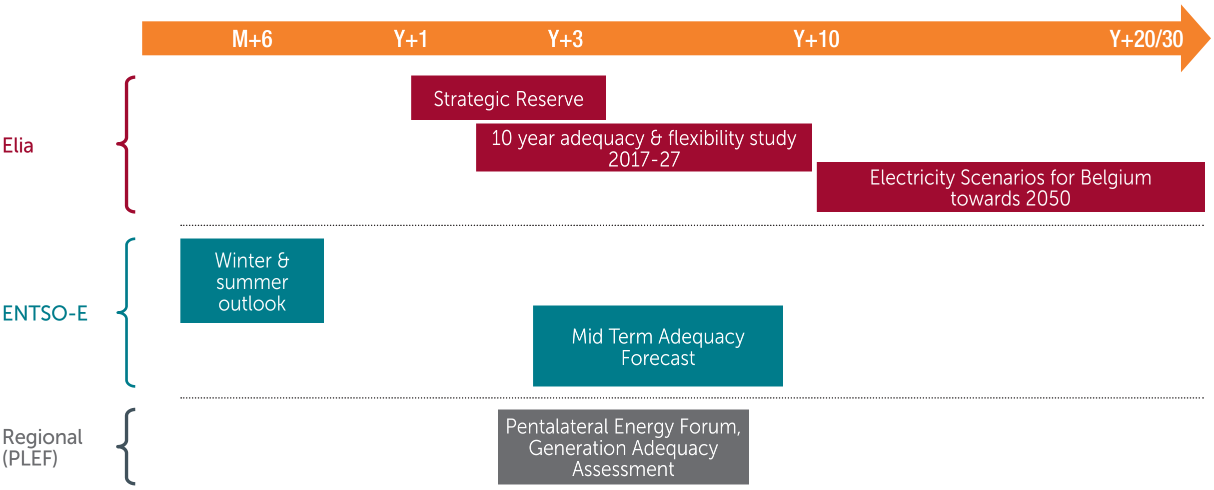
Key stakeholders on the market have been engaged in a continuous interaction process to design the most adequate methodology to determine the volumes of market response in Belgium and to apply the methodology to assess the relevant volumes and activation constraints of market response for the volume assessments (see section 3.3).

25. High-Voltage Direct Current.

1.8 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 study is detailed further below.

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



Elia is committed to ensuring a high level of consistency between the above-mentioned assessments by:

i) developing and applying a common probabilistic methodology and

ii) ensuring complementarity of the results obtained between the different studies.

The pan-European, regional and national studies shown above share the same probabilistic methodology, therefore enabling consistent analyses and comparisons. It should be noted as well that due to the different scope, purpose and time of completion of the different studies, some updates in the methodological assumptions and data might be considered.

1.8.1. ELIA'S 2017-2027 ADEQUACY AND FLEXIBILITY STUDY

Elia adequacy and flexibility study 2017-2027

LINK:	CLICK HERE [12], [13]
METHOD:	Probabilistic
TIME-FRAME:	2017-2021-2023-2027
LATEST 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 the analysis of security of supply, the Belgian Federal Minister for 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 for 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 for Energy. This addendum was also presented to and shared with market parties and is publically available on Elia's website [13].

1.8.2. ELECTRICITY SCENARIOS FOR BELGIUM TOWARDS 2050

Electricity Scenarios for Belgium towards 2050

LINK:	CLICK HERE [77]
METHOD:	Probabilistic
TIME-FRAME:	2030-2040-2050
LATEST PUBLICATION:	11/2017
SCOPE:	22 countries
COUNTRY RESULTS:	Belgium
FREQUENCY OF PUBLICATION:	ad hoc Elia publication

This study builds on the Elia report 'The need for adequacy and flexibility in the Belgian electricity system for 2017-2027' (see previous box).

This study analyses both short-term and long-term policy options on the future energy mix for Belgium on the path towards 2050, bearing in mind the planned nuclear phase-out in 2025, and striving towards a sustainable and adequate electricity system.

In addition to putting figures to the various future scenarios for 2030 and 2040, the study also focuses on a few options for sustainability ensuring security of supply in the short term. These are needed in order to cope with the planned 2025 nuclear exit and to provide sufficient replacement capacity for guaranteeing security of supply.

1.8.3. ENTSO-E: OUTLOOK REPORTS

ENTSO-E Winter and Summer outlooks

LINK:	CLICK HERE [78]
METHOD:	Deterministic
TIME-FRAME:	next winter/summer
LATEST 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[26] publishes a report entitled 'Winter Outlook and Summer Review'. One of the focal points of this short-term adequacy report is the main adequacy risk 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.

26. ENTSO-E: European Network of Transmission System Operators for Electricity: Organisation representing 43 TSOs from 36 countries.

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.

It is currently under discussion within ENTSO-E for this assessment to evolve into a probabilistic assessment.

1.8.4. ENTSO-E: MID-TERM ADEQUACY FORECAST

ENTSO-E Mid Term Adequacy Forecast

LINK:	CLICK HERE [16]
METHOD:	Probabilistic
TIME-FRAME:	2020 - 2025
LATEST PUBLICATION:	09/2017
SCOPE:	all pan EU perimeter
COUNTRY RESULTS:	all pan EU perimeter
FREQUENCY OF PUBLICATION:	Yearly

Every year, until 2015, ENTSO-E published the 'Scenario Outlook & Adequacy Forecast' (SO&AF). 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. Recently the new edition of this report, MAF 2017, has been published and submitted for public consultation [16]. The study gives stakeholders in the European energy market an overview of the national and European adequacy situation. The assessment uses best-estimate scenarios based on a bottom-up data collection from TSOs, and focuses on the LOLE and ENS as adequacy indicators. Both 2016 and 2017 reports include an assessment for 2020 and 2025 covering all European countries. The MAF study is the first pan-European adequacy assessment using several probabilistic models but the same methodology.

The following improvements in the methodology and data were considered for the MAF 2017 version:

- the inclusion of demand-side response;
- the extension of the climate database to multiple years (from 13 to 34);
- consolidation and standardisation of the database;
- the assessment of more generation scenarios including mothballing sensitivities;
- alignment of approaches regarding the technico-economic optimisation performed by the different tools used.

Elia is actively contributing as one of the modelling parties within MAF and towards improving the methodology and modelling for subsequent editions as the planned improvements are fully coherent with Elia's adequacy assessment approach.

1.8.5. PENTALATERAL ENERGY FORUM (PLEF): REGIONAL GENERATION ADEQUACY ASSESSMENT

Pentalateral Energy Forum Adequacy study

LINK:	CLICK HERE [79]
METHOD:	Probabilistic
TIME-FRAME:	2018-19 - 2023-24
LATEST PUBLICATION:	01/2018 (forthcoming)
SCOPE:	all pan EU perimeter
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[27] (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), both for the various countries and for 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 currently ongoing and its publication is planned for early 2018 and will cover winters 2018-19 and 2023-24. Elia is actively contributing as one of the modelling parties within PLEF.

The following improvements in the methodology and data have been considered in the PLEF 2017 study:

- alignment with MAF data for the countries outside the CWE area considered;
- use of MAF climate database to more years (from 13 to 34);
- assessment of specific regional sensitivities, e.g. economic risk, environmental constraints (decarbonisation), long term nuclear unavailability;
- implementation of a flow-based method in line with the national studies by Elia and RTE.

27. The Pentalateral Energy Forum has been expanded to include the Swiss and Austrian TSOs.

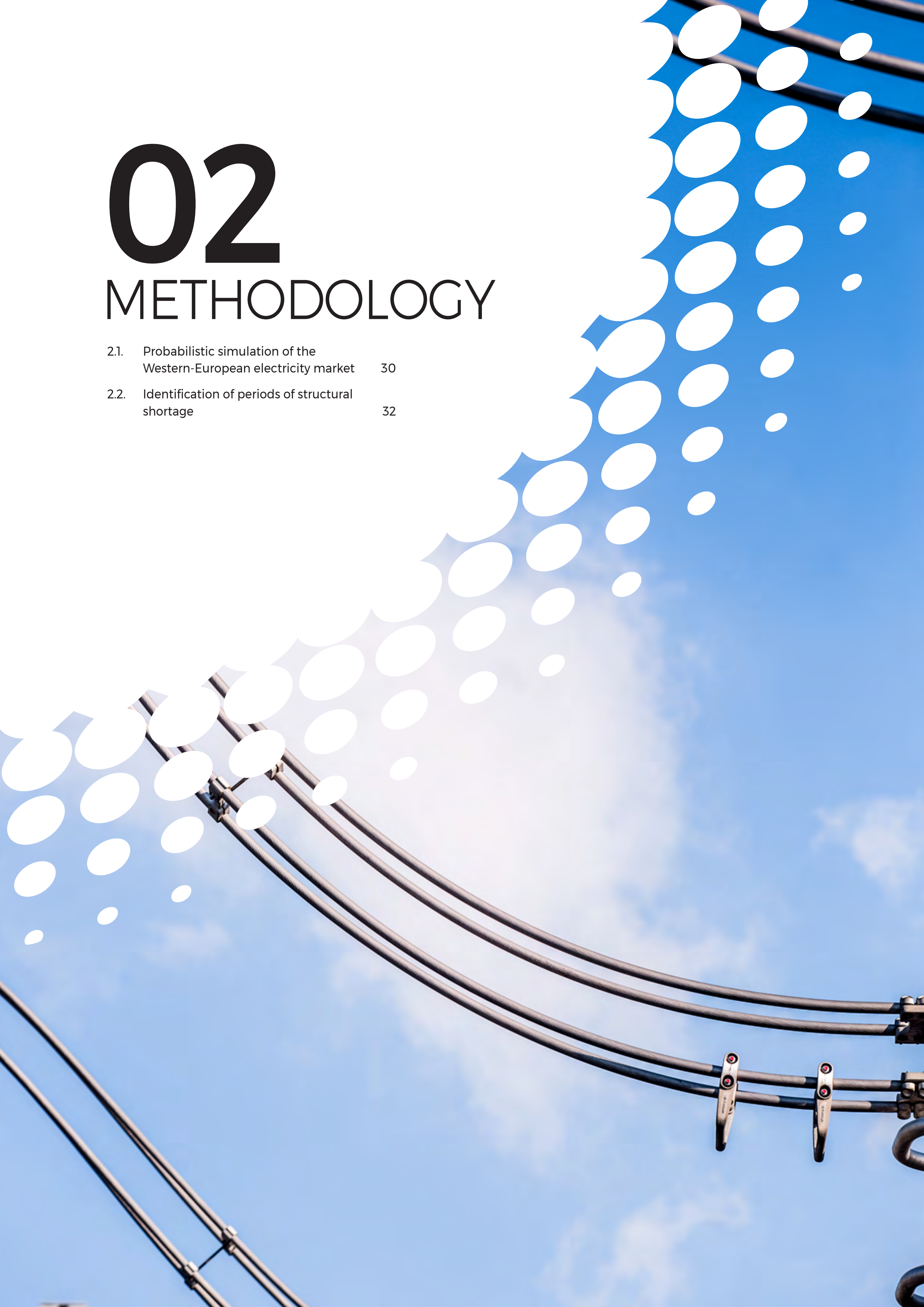
1.9 DISCLAIMER

This report provides a probabilistic assessment of Belgium's security of supply and the need for strategic reserve for winters 2018-19, 2019-20 and 2020-21. The assessment takes into account the following key assumptions:

- Within the calculated volume, no distinction is made between demand reduction 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.

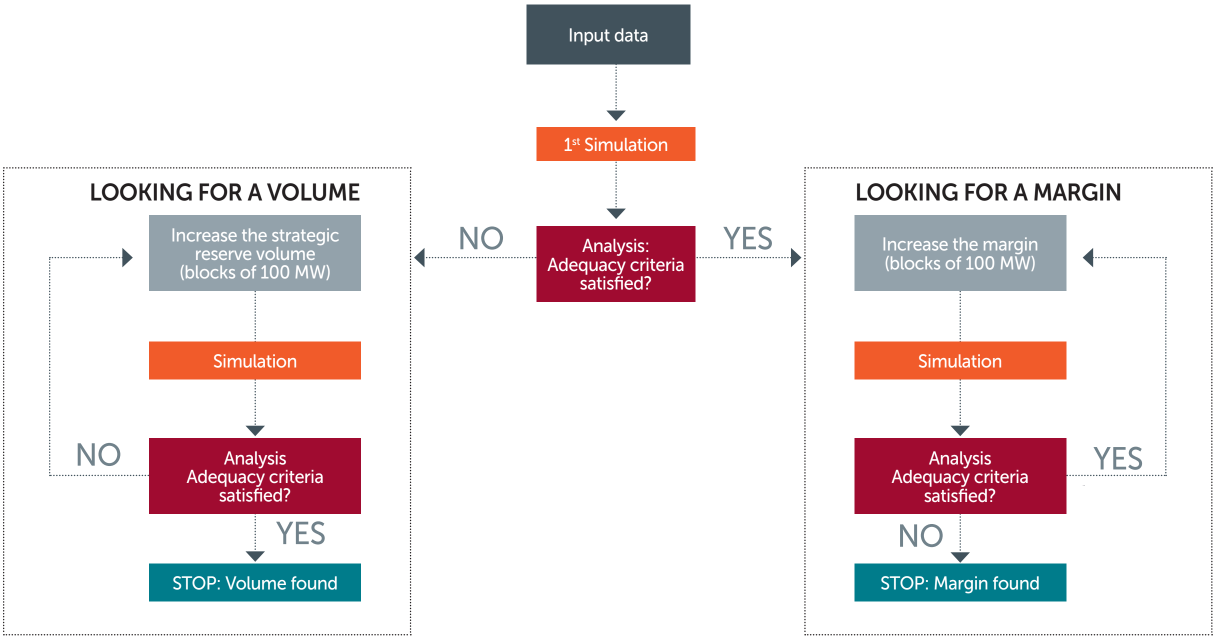
Elia would like to stress that the conclusions of this report are inextricably linked to the initial assumptions set out in this report. Elia is not liable for these assumptions being realised, as in most cases they relate to developments falling outside the direct control of the grid operator.

02
METHODOLOGY

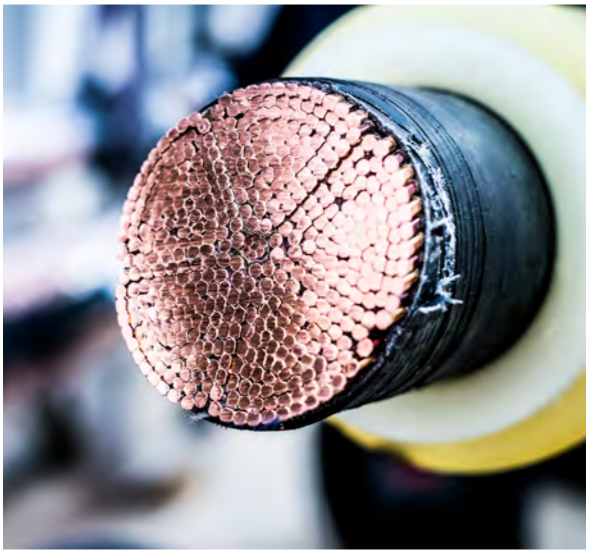


The necessary volume of strategic reserve for a specific winter is determined using the iterative process depicted in Figure 14. At the start of the process, it is determined whether a margin or a necessary volume of strategic reserve is identified for the studied situation. If both legal criteria are not met, additional strategic reserve volume is needed. On the other hand, if the simulation without additional volume of strategic reserve is already compliant with both legal criteria, the margin on the system will be sought. The extra volume or margin is increased by 100 MW blocks until the legal criteria are met. 100 MW-block resolution is also used in other adequacy analyses performed by TSOs as well as within the context of ENTSO-E analyses.

ITERATIVE PROCESS TO CALCULATE THE VOLUME OF STRATEGIC RESERVE OR THE MARGIN (FIG. 14)



At each iteration step, a full probabilistic simulation of the Western-European electricity market is performed. This simulation, which is performed on an hourly basis for the winter in question, is described in section 2.1. The hourly output of this probabilistic simulation is subsequently analysed to determine whether the two adequacy criteria are satisfied. The identification of hours in which a structural shortage is present is illustrated in section 2.2. Depending on whether a margin or a needed volume of strategic reserve is sought, the iterative process is halted according to Figure 14.



PROBABILISTIC SIMULATION OF THE WESTERN-EUROPEAN ELECTRICITY MARKET

The **first part of each iteration** step consists of the **probabilistic simulation of the Western-European electricity market**. This probabilistic simulation is done in roughly two separate steps:

1. Construction of 'Monte Carlo' years (section 2.1.1);
2. Simulation of each 'Monte Carlo' year (section 2.1.2).

In this chapter, we give a brief summary of the way the probabilistic simulation is performed. The whole simulation process, as well as the tools and methods used are described in greater **detail in the appendix** (Chapter 8).

In this chapter, we give a brief summary of the way the probabilistic simulation is performed. The whole simulation process, as well as the tools and methods used are described in greater **detail in the appendix** (Chapter 8).

As Belgium depends on electricity imports for its security of supply, explicit modelling of its neighbouring countries is compulsory. For this study, the individual modelling of twenty neighbouring countries is done, as shown in Figure 15. More specifically, the following countries are modelled: Germany (DE), France (FR), Belgium (BE), the Netherlands (NL), Luxembourg (LU), Austria (AT), 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).

Due to the specific market situation in Italy, Denmark, Norway and Sweden, these countries are modelled with multiple market nodes. This type of specific modelling is in line with the real market situation, and is identical to the approach used in other studies done e.g. within ENTSO-E.

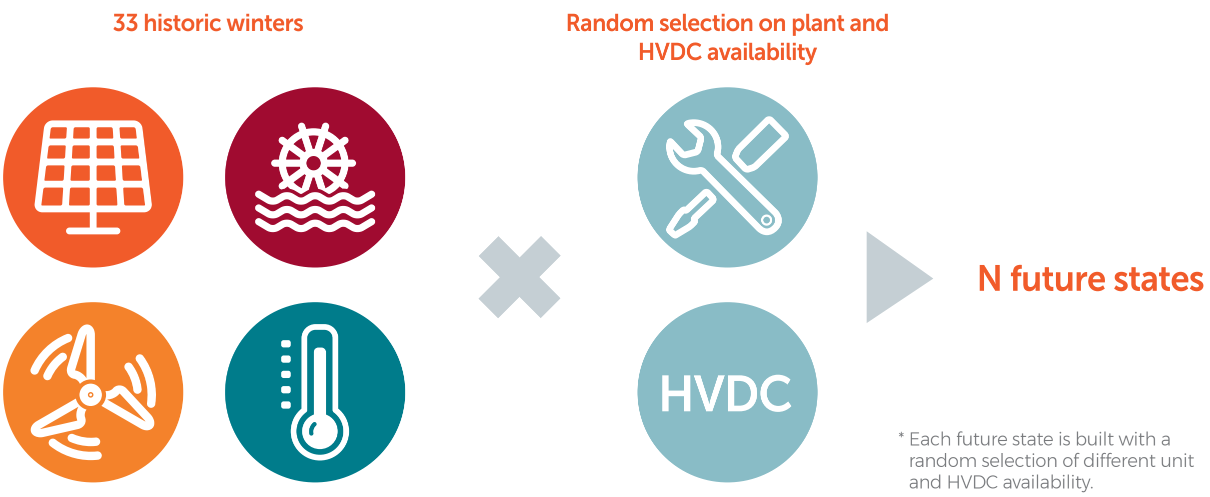
FOR THE PROBABILISTIC SIMULATION, 20 COUNTRIES ARE MODELLED INDIVIDUALLY (FIG. 15)

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

2.1.1. CONSTRUCTION OF 'MONTE CARLO' YEARS

For each of the countries simulated, a large number of future states – also called 'Monte Carlo' years – are constructed. Each future state is established on the basis of historical data on meteorological conditions (wind, sun, temperature, and precipitation), power plant and HVDC link unavailability, by convolution of different climatic conditions with random availability of power plants and HVDC links, as illustrated in Figure 16. For this analysis, climatic variables are modelled using data of 33 historical winters.

CONSTRUCTION OF 'MONTE CARLO' YEARS (FIG. 16)



2.1.2. SIMULATION OF EACH 'MONTE CARLO' YEAR

The constructed 'Monte Carlo' years are next used as an input for the simulation of the Western-European electricity market. A detailed modelling of the power plants' economic dispatch is performed. The assessment takes into consideration *inter alia* power plants' marginal costs and also enables the pumped-storage power plants and hydroelectric reservoirs to be appropriately modelled. Furthermore in the adequacy assessment, the model also correctly considers that in periods of structural shortage, all of the available generation facilities will be taken into account, operating at their maximum capacity, in order to minimise the shortage.

The market simulator used in the scope of this study is ANTARES, a sequential 'Monte Carlo' multi-area simulator developed by French TSO RTE, the purpose of which is to assess generation adequacy problems and economic efficiency issues. The different input and outputs of the model are depicted in Figure 17.

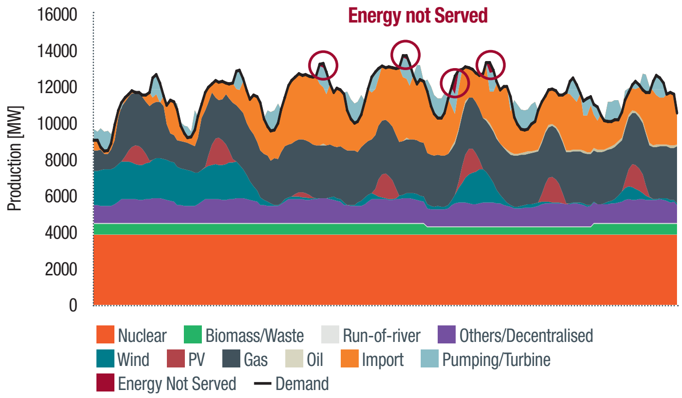
INPUT AND OUTPUT DATA FOR THE MODEL (FIG. 17)

2.2 IDENTIFICATION OF PERIODS OF STRUCTURAL SHORTAGE

The second part of each iteration step involves identifying periods of structural shortage, i.e. times when the generation and imports of electricity are insufficient to meet demand. To this end, the output of the probabilistic market simulation is assessed on an hour-by-hour basis by simulating the European electricity market.

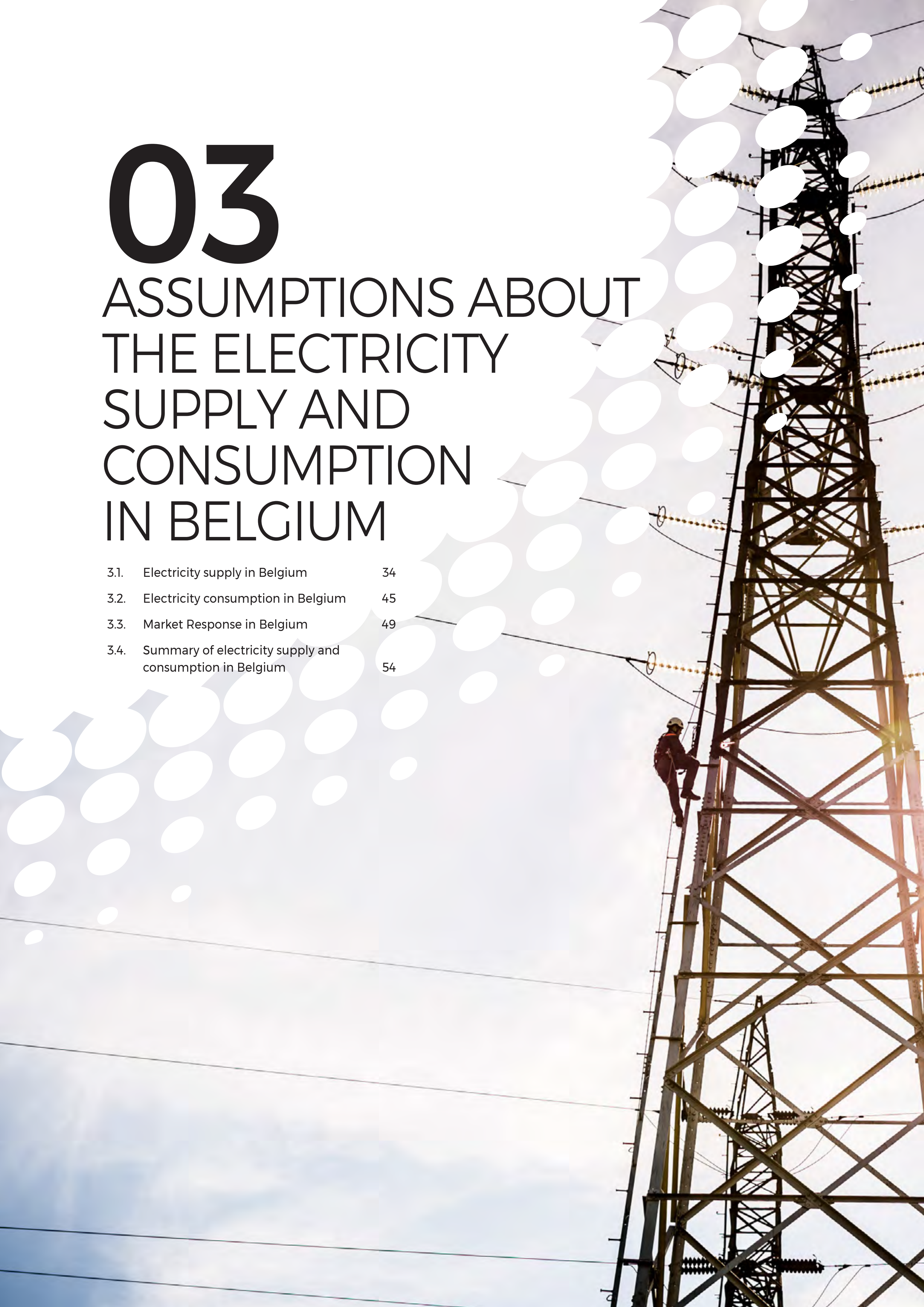
Figure 18 gives an example of how consumption is covered by the available generation facilities and imports for every hour of the week. If, for a given hour, the combination of generation capacity, imports and market response falls short (by 1 MW or higher) of the capacity required for meeting demand, this corresponds to one hour of structural shortage, where 'Energy - Not Served' (ENS) occurs. The average amount of all such hours, within the Monte Carlo approach, is then referred to as 'Lost Of Load Expectation' (LOLE). Figure 18 illustrates the energy that cannot be supplied by the generation facilities and imports.

EXAMPLE FOR GENERATION PER PRODUCTION TYPE FOR A GIVEN WEEK FOR BELGIUM (FIG. 18)



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

03 ASSUMPTIONS ABOUT THE ELECTRICITY SUPPLY AND CONSUMPTION IN BELGIUM



This section elaborates on the assumptions used in this analysis for Belgium. As mentioned in section 1.6, Elia organised a public consultation on the raw data for Belgium.

In **section 3.1**, the hypotheses used with regard to the **Belgian electricity supply** are detailed. Next, **section 3.2** elaborates on **Belgian electricity demand**, and the way its specifics are incorporated in the model. **Section 3.3** provides the details for the **Belgian market response**. Lastly, **section 3.4 summarises** the input data for Belgium.

ELIA CONTRIBUTES TO MORE TRANSPARENT INFORMATION ON THE BELGIAN ELECTRICITY SYSTEM

Elia provides a large volume of data in real time on its website [22] to give stakeholders an overview of the Belgian transmission system. The data sets made publicly available on Elia's website include:

- total Belgian load and Elia grid load;
- photovoltaic and wind production data and forecasts;
- generation capacity forecasts.

These data sets and many more can be downloaded for detailed analysis. Furthermore, Elia contributes to the ENTSO-E transparency platform [27] by providing real-time data.

Elia organised a public consultation on the detailed assumptions used for Belgium in this analysis. See section 1.6 for more information.

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 Act, Elia received input from the Directorate-General of Energy at Federal Public Service (FPS) Economy prior to 15 October 2017. The information received from FPS Economy was included in the report and taken into account in the analysis.

3.1.1. WIND AND SOLAR FORECASTS

FPS Economy consults the three Belgian regional authorities, 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 takes as its basis 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.

This section provides an overview of the assumptions made with regard to the Belgian electricity supply. The modelling details are provided in Chapter 8 (Appendix).

3.1.1.1. WIND ONSHORE

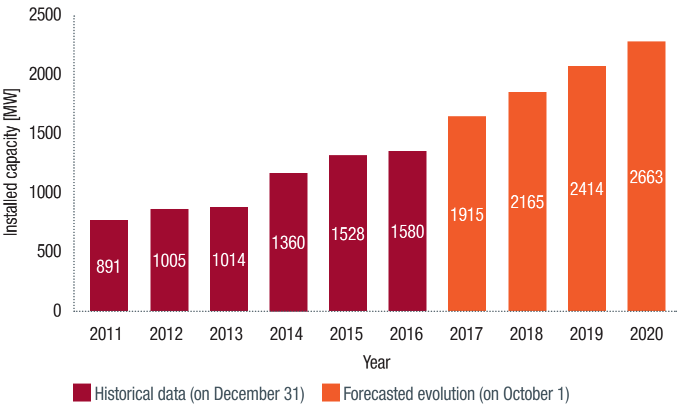
Figure 19 shows the historical evolution of the installed capacity of onshore wind generation, as well as the forecast consolidated by FPS Economy. On average, the forecast evolution amounts to a yearly increase of 250 MW. For illustration purposes, the geographical distribution of the onshore wind farms in Belgium for 2017 is shown in Figure 20.

+ 250 MW / YEAR

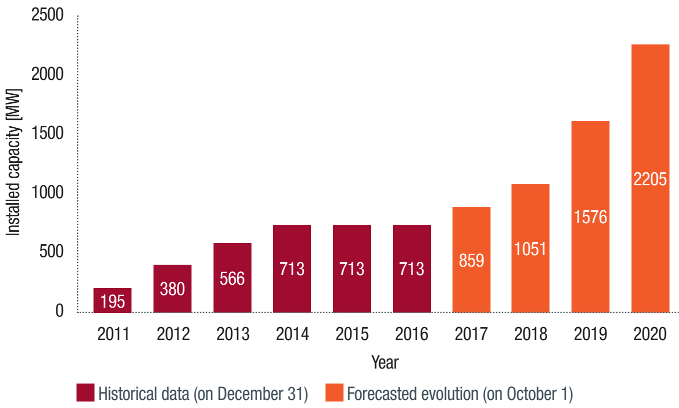
3.1.1.2. WIND OFFSHORE

The Belgian government has awarded domain concessions for the construction and exploitation of offshore wind electricity production to nine wind farms (see Figure 22). With the commissioning of the Nobelwind wind farm in 2017, the total installed capacity of offshore wind will be 859 MW by the end of 2017. Figure 21 shows the historical evolution of installed capacity of offshore wind, 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.

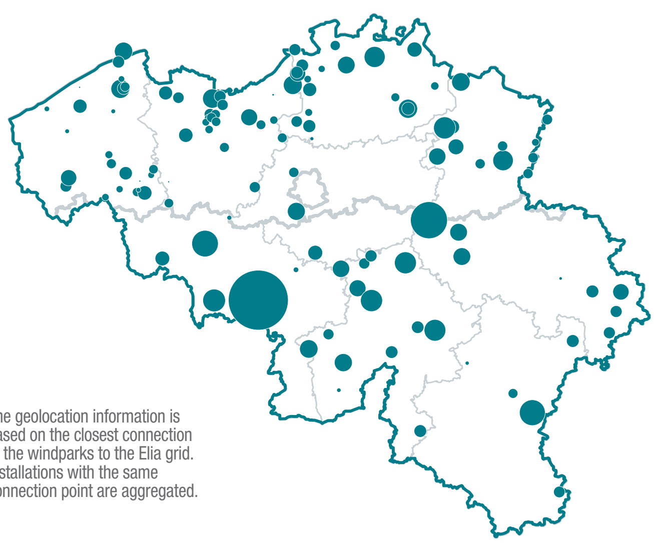
EVOLUTION AND FORECAST OF INSTALLED CAPACITY ONSHORE WIND (FIG. 19)



EVOLUTION AND FORECAST OF INSTALLED CAPACITY OFFSHORE WIND (FIG. 21)

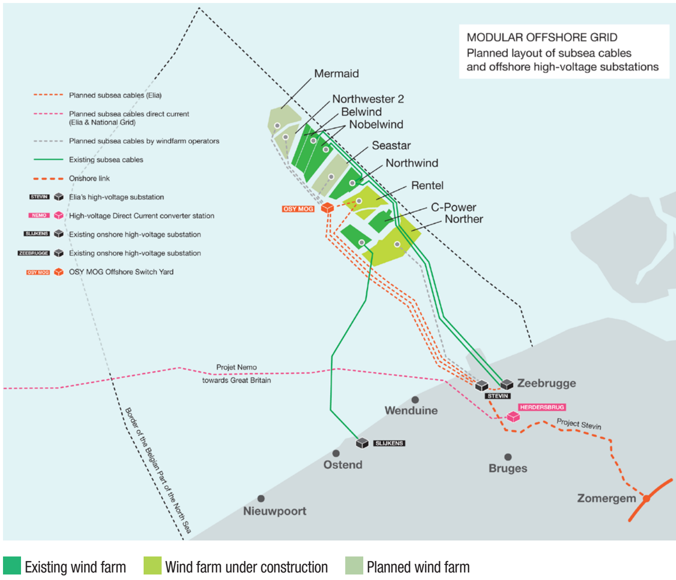


GEOGRAPHICAL DISTRIBUTION OF THE BELGIAN ONSHORE WIND PRODUCTION (WINTER 17-18) (FIG. 20)



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

OFFSHORE WIND CONCESSIONS IN THE BELGIAN NORTH SEA (FIG. 22)

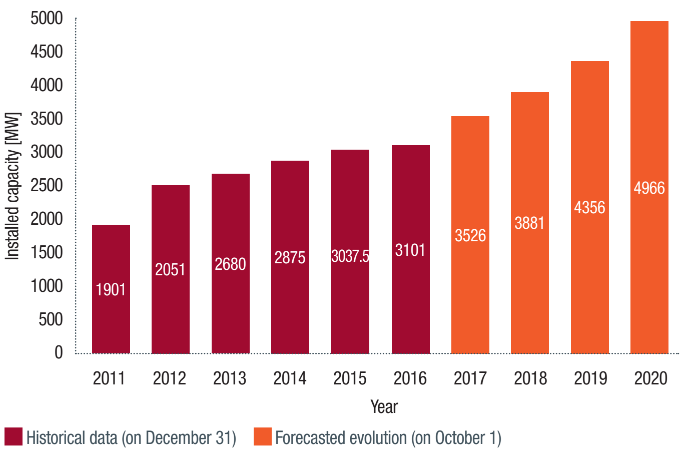


3.1.1.3. SOLAR

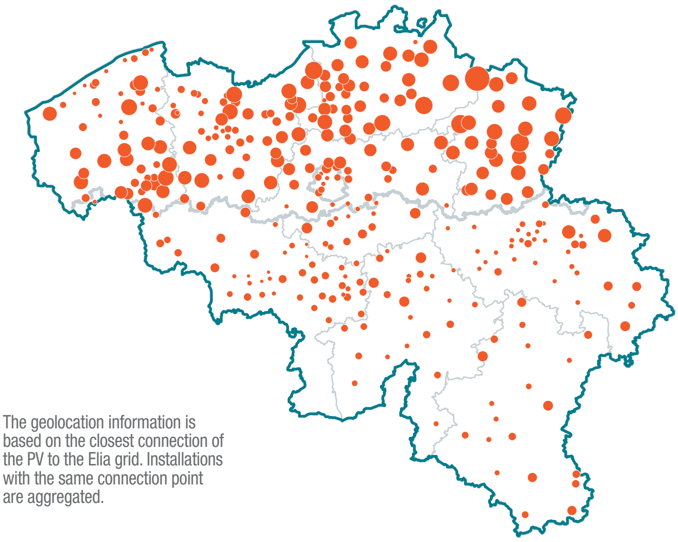
Figure 23 shows the historical evolution of installed capacity of photovoltaic (PV) generation in Belgium. It contains the forecast used in this analysis, which was consolidated by FPS Economy. On average, a yearly increase of approximately 450 MW per year is taken into account. For illustration purposes, Figure 24 shows the geographical distribution of the installed capacity PV in Belgium for 2017.

+ 450 MW / YEAR

EVOLUTION AND FORECAST OF INSTALLED CAPACITY PV (FIG. 23)



GEOGRAPHICAL DISTRIBUTION OF THE BELGIAN PHOTOVOLTAIC ELECTRICITY PRODUCTION (WINTER 2017-18) (FIG. 24)



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

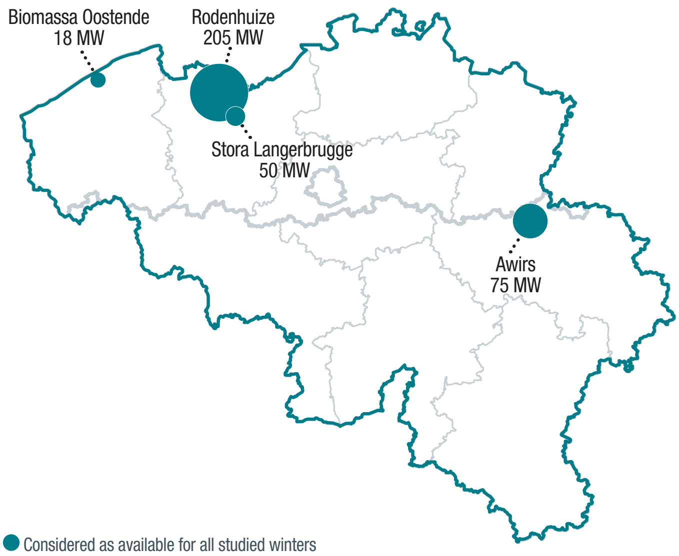
3.1.2. BIOMASS, WASTE AND COMBINED HEAT & POWER FACILITIES

This section elaborates on the installed capacity of biomass, waste and Combined Heat & Power (CHP) production facilities for Belgium. 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. Units subject to a CIPU[28] contract, as well as units for which such a contract does not apply, are both considered in the database.

When the unit is subject to a CIPU contract, its owner is obliged to notify Elia about the unit's availability. 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 lower installed capacity. It has been agreed with the distribution system operators that all units with an installed capacity greater than 0.4 MW must 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 aggregated. The database contains both information concerning units that are **in service**, but also projects that are currently **in development**.

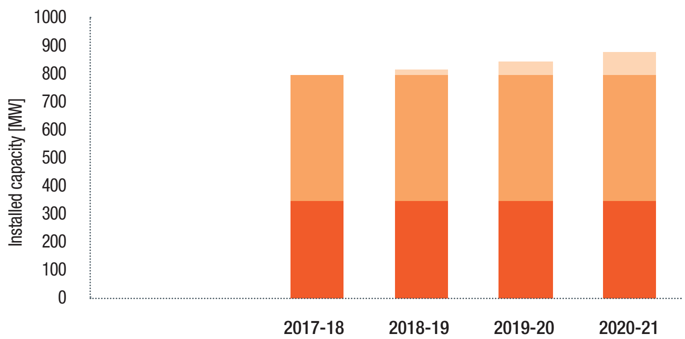
After discussion with FPS Economy, it was decided to use the information in the Elia production unit database to determine installed **biomass** production capacity. Following the cancellation of the Langerlo biomass conversion project, which was scheduled to be in operation by winter 2018-19, this production unit is no longer taken into account. A capacity growth elaborated by FPS Economy after consultation with the regions has subsequently been added in order to obtain the installed production capacity for the next three winters. This forecast is globally in line with the information in the Elia database. Figure 26 shows the forecast trend in installed capacity of biomass electricity production in Belgium. The figure differentiates as to whether a CIPU contract applies to the units or not. Furthermore, 'additional biomass units' are included according to the forecast provided by FPS Economy. These 'additional biomass units' are considered as not being subject to a CIPU contract. In Figure 25, the location of the biomass production units with a CIPU contract is shown for information.

TOTAL INSTALLED CIPU BIOMASS CAPACITY IN BELGIUM FOR ALL STUDIED WINTERS (FIG. 25)



Total installed CIPU capacity considered for all studied winters: **348 MW**

FORECASTED EVOLUTION OF INSTALLED CAPACITY BIOMASS (FIG. 26)



	2017-18	2018-19	2019-20	2020-21
Additional biomass (non-CIPU)	0	18	46	80
Biomass non-CIPU	446	446	446	446
Biomass CIPU	348	348	348	348

FINAL CURTAIN FALLS FOR LANGERLO: 2 BILLION EURO PROJECT SCRAPPED

Source: deredactie.be – 8 April 2017

There will be no biomass power plant in Langerlo (Limburg province). The company behind the project, Graanul Invest of Estonia, has filed for bankruptcy. The whole project has been scrapped; the Flemish government will not have to pay out 2 billion euros in green subsidies, but on the other hand some 100 people will lose their job.

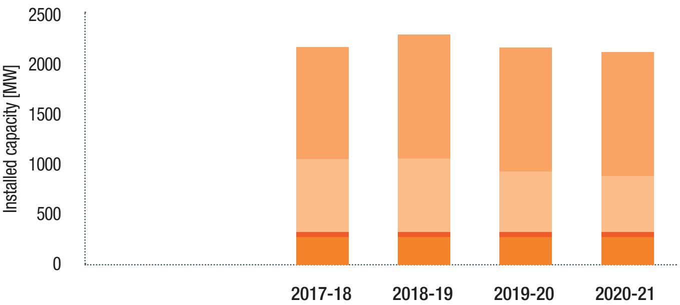
[...]

Langerlo used to be a coal factory, generating energy by burning charcoal. Since this is no longer meeting modern standards concerning air pollution and sustainability, the factory was to be transformed into a biomass plant.

28. CIPU: Contract for the Injection of Production Units. The signatory of the CIPU contract is the single point of contact at Elia for aspects relating to 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 FPS Economy to base the installed capacity forecast on the information available in the Elia production database. Only projects communicated to Elia that are in a sufficiently mature phase in their development are taken into account in this analysis. Figure 27 shows the forecast evolution of installed capacity CHP and waste. Again, the figure differentiates the units based on whether the unit is subject to a CIPU contract or not. No change is foreseen for the installed capacity of waste-fuelled units, and an increase of approximately 100 MW is taken into account for CHP units without a CIPU contract based on the Elia production database. For CHP units with a CIPU contract, a combined decrease of 169 MW is forecast after winter 2018-19.

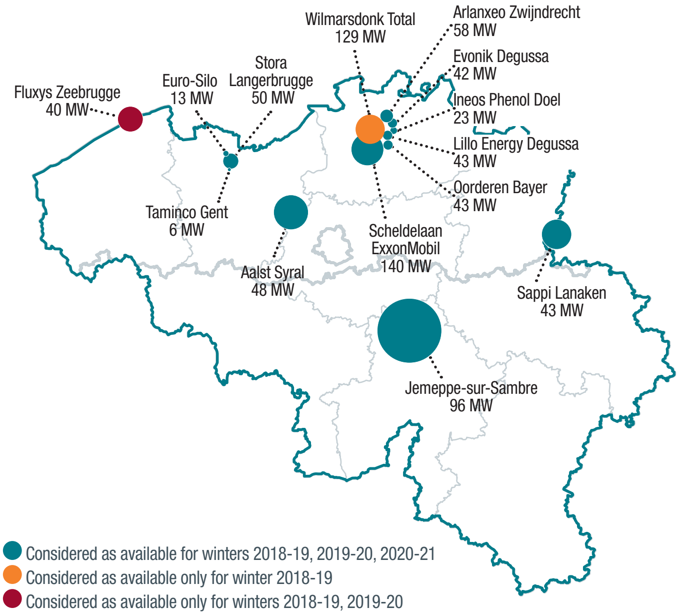
FORECASTED EVOLUTION OF INSTALLED CAPACITY CHP AND WASTE (FIG. 27)



	2017-18	2018-19	2019-20	2020-21
CHP non-CIPU	1111	1231	1231	1231
CHP CIPU	724	724	595	555
Waste non-CIPU	51	51	51	51
Waste CIPU	280	280	280	280

In Figure 28 and Figure 29, the geographical location of the installed capacity of CHP and waste units with a CIPU contract is given for illustrative purposes.

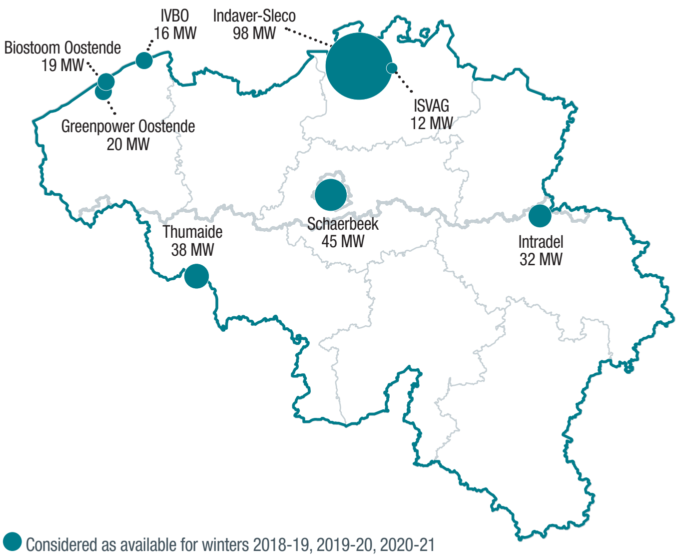
TOTAL INSTALLED CIPU CHP CAPACITY AVAILABLE IN BELGIUM FOR ALL STUDIED WINTERS (FIG. 28)



Considered as available for winters 2018-19, 2019-20, 2020-21
Considered as available only for winter 2018-19
Considered as available only for winters 2018-19, 2019-20

Total installed CIPU capacity considered in the 'base case' for winter 2018-19: **724 MW**

TOTAL INSTALLED CIPU WASTE CAPACITY AVAILABLE IN BELGIUM FOR ALL STUDIED WINTERS (FIG. 29)



Considered as available for winters 2018-19, 2019-20, 2020-21

Total installed waste CIPU capacity considered in the 'base case' for winter 2018-19: **280 MW**

3.1.3. THERMAL PRODUCTION WITH A CIPU CONTRACT

In this section, details on Belgian thermal production units with a CIPU contract are provided. For biomass, waste and CHP production, these units were discussed above in section 3.1.2. Below, we first elaborate on the installed capacity of those thermal units with a CIPU contract (section 3.1.3.1). Since units with a CIPU contract are modelled individually, outages of individual units are taken into account. This is described in greater detail in section 3.1.3.2

3.1.3.1. INSTALLED CAPACITY OF THERMAL PRODUCTION WITH A CIPU CONTRACT

The installed capacity of Belgian thermal production with a CIPU contract is consolidated by Elia and FPS Economy based on the information provided by producers to the Federal Minister for Energy, FPS Economy, CREG and Elia as set out in the Electricity Act. These parties cannot be held accountable for the realisation of the provided hypotheses, since this is the responsibility of the producers. Figure 30 shows the forecast for the thermal production units with a CIPU contract.

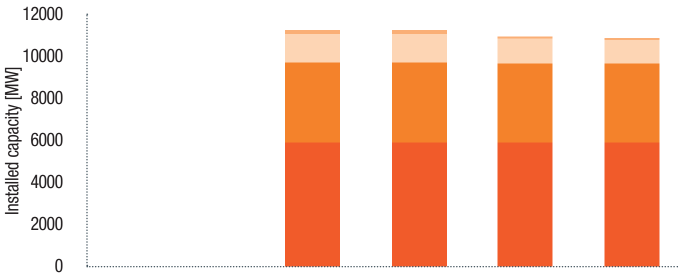
Section 3.1.2 already gives the details for the Belgian **biomass, waste, and CHP** units with a CIPU contract. In April 2016, the decommissioning of the Langerlo coal plant marked the closure of the last big **coal** plant in Belgium.

The hypothesis used in this analysis with regards to the installed capacity of **nuclear** electricity production is aligned with the law concerning the nuclear phase out. This law was amended twice:

- The lifespan of the Tihange 1 power plant (installed capacity of 962 MW) was extended by ten years with the 2013 amendment of the law;
- 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 stay operational for and additional ten years.

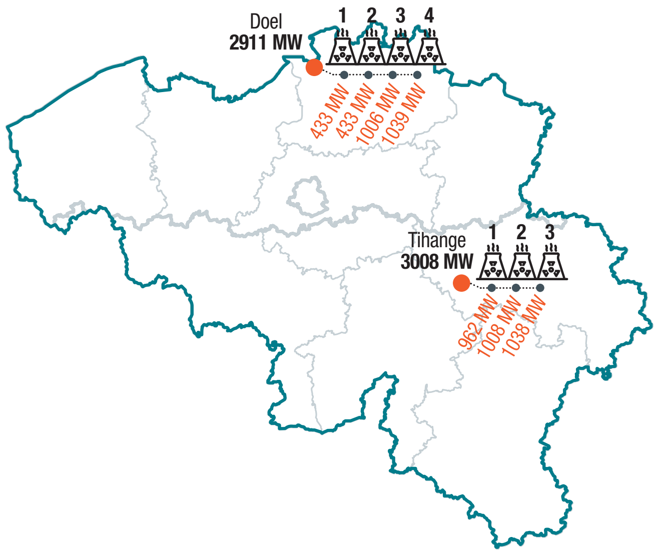
In line with the modified Belgian law on the nuclear phase-out, it is assumed that in the 'base case' all seven nuclear reactors (5919 MW) are operational for the entire period covered by the study. In Figure 31 the geographical location of the installed capacity of nuclear electricity production is given.

FORECAST OF THE INSTALLED CAPACITY THERMAL UNITS WITH CIPU CONTRACT (FIG. 30)



	2017-18	2018-19	2019-20	2020-21
Turbojet	158	158	68	68
Biomass, CHP, and Waste	1352	1352	1223	1183
Gas CCGT/GT/CL	3846	3846	3776	3776
Nuclear	5919	5919	5919	5919

INSTALLED NUCLEAR CAPACITY IN BELGIUM (FIG. 31)



Total installed capacity considered in the 'base case' for winters 2018-19, 2019-20 and 2020-21: **5919 MW**

In line with the amended Belgian law on the nuclear phase-out, it is assumed that in the 'base case' all seven nuclear reactors (5919 MW) are operational for the whole period of the study.

In recent years, several thermal units have been taken off the market. Some of these units were contracted in the context of the strategic reserve. For this analysis, it is assumed that all units currently participating in the strategic reserve for winter 2017-18 will not return to the market. For illustration purposes, the geographical distribution of CCGT/CL and OCGT units in Belgium is shown in Figure 32 and Figure 33 respectively. The installed capacity for the turbojet units in Belgium is summarised in Figure 34.

The **Drogenbos** gas-fired production unit can operate both in CCGT (460 MW) and OCGT (230 MW) mode. Based on information by the owner of the production unit, the Drogenbos production unit will be taken into account as an OCGT in the 'base case' analysis. For an analysis with the Drogenbos power plant operating as CCGT, see the sensitivity described in section 6.2.3.

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.

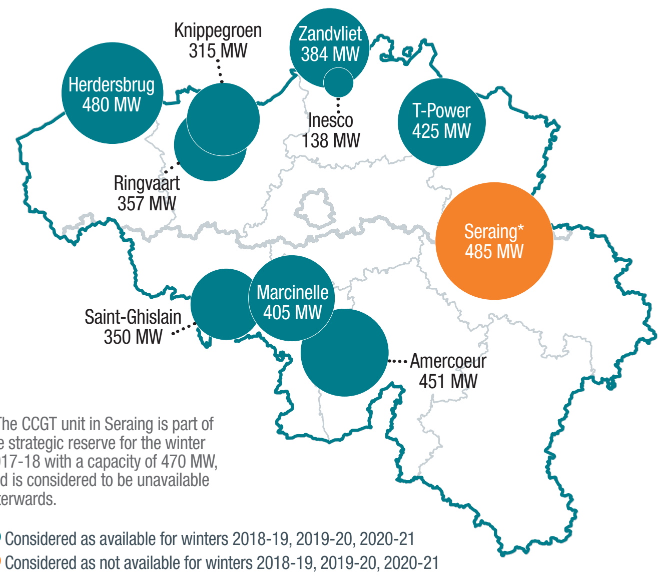
A permanent shutdown can only occur after 30 September of the year following the notification referred to in paragraph 1. A notice of shutdown is required for each installation for power generation connected to the transmission grid, whether a prior individual authorisation in accordance with Article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

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

§ 3. No permanent or temporary 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 CCGT/CL CAPACITY AVAILABLE IN BELGIUM (FIG. 32)

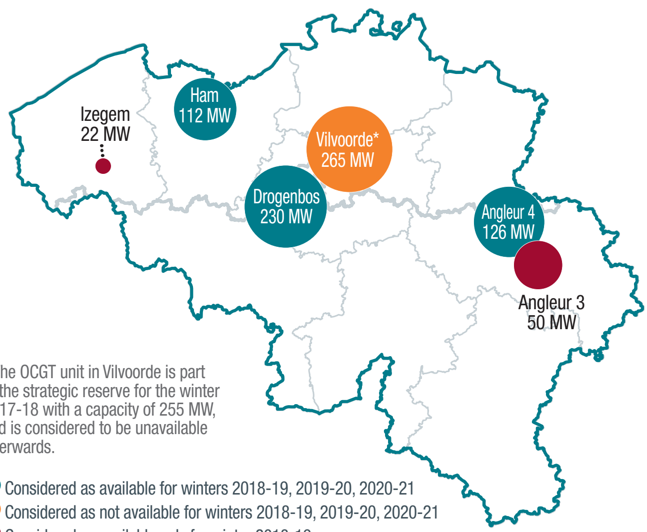


* The CCGT unit in Seraing is part of the strategic reserve for the winter 2017-18 with a capacity of 470 MW, and is considered to be unavailable afterwards.

- Considered as available for winters 2018-19, 2019-20, 2020-21
- Considered as not available for winters 2018-19, 2019-20, 2020-21

Total installed CIPU capacity considered in the 'base case' for winters 2018-19, 2019-20, 2020-21: **3308 MW**

TOTAL INSTALLED OCGT CAPACITY AVAILABLE IN BELGIUM (FIG. 33)

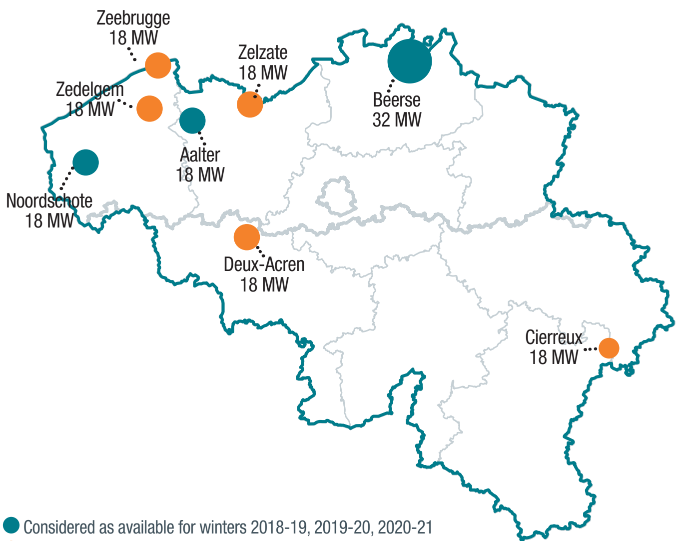


* The OCGT unit in Vilvoorde is part of the strategic reserve for the winter 2017-18 with a capacity of 255 MW, and is considered to be unavailable afterwards.

- Considered as available for winters 2018-19, 2019-20, 2020-21
- Considered as not available for winters 2018-19, 2019-20, 2020-21
- Considered as available only for winter 2018-19

Total installed capacity considered in the 'base case' for winter 2018-19: **538 MW**

TOTAL INSTALLED TURBOJET CAPACITY AVAILABLE IN BELGIUM (FIG. 34)



- Considered as available for winters 2018-19, 2019-20, 2020-21
- Considered as available only for winter 2018-19

Total installed capacity considered in the 'base case' for winter 2018-19: **158 MW**

3.1.3.2. AVAILABILITY OF THERMAL PRODUCTION WITH A CIPU CONTRACT

Belgian thermal production units with a CIPU contract are modelled individually in the ANTARES model. The analysis takes into account two types of unavailability for the CIPU production units:

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

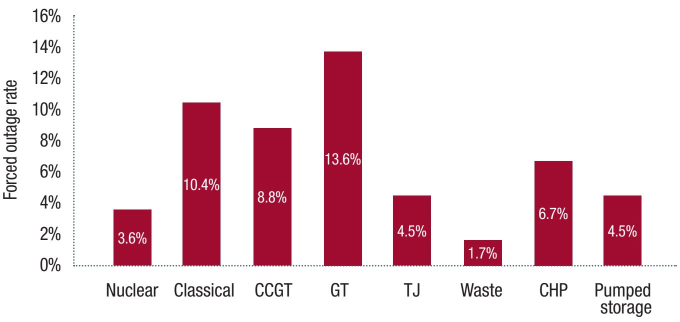
Planned unavailability

In recent years, less and less maintenance is planned during the course of winter. Together with the producers, Elia aims to schedule all planned unavailability outside of the winter period (see box 'Method and hypotheses used for the calculation of the maximal maintenance curve' for details next page). For 2018, a maintenance schedule has already been established and is taken into account in the analysis of the months of 2018 corresponding to winter 2018-19. Furthermore, since the 2019 maintenance schedule is not yet known, no planned unavailability of units for which a CIPU contract applies is thus considered for the months of 2019 corresponding to winter 2018-19. Similarly, for the analysis of winters 2019-20 and 2020-21, no planned unavailability is considered in the course of the entire winter.

Unplanned unavailability

On top of the planned unavailability this study takes into account unplanned or forced unavailability. An analysis has been conducted for each production type (CCGT, gas turbine, turbojet, etc.), based on the historical unplanned unavailability for the period 2007-2016. The analysis is conducted using the availability information of the production units that are nominated in the day-ahead market and the result is shown in Figure 35. See also section 8.1.4 for further details.

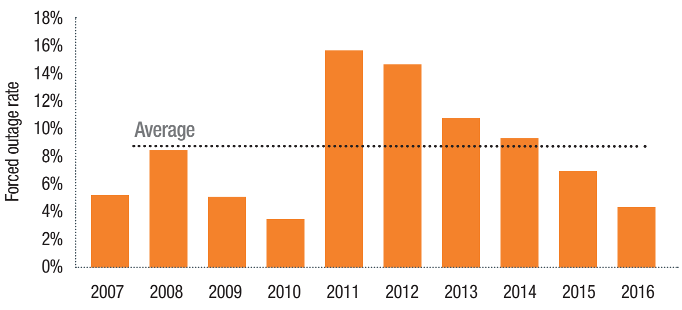
BELGIAN AVERAGE FORCED OUTAGE RATE OVER 2007-2016 PER PRODUCTION TYPE (FIG. 35)



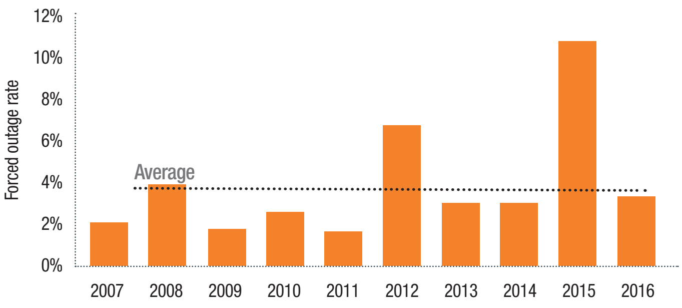
The unavailability of the Doel 4 (August 2014 to December 2014), Doel 3 and Tihange 2 (March 2014 to December 2015), and Tihange 1 (September 2016 to May 2017) nuclear plants are not taken into account in the determination of the above-mentioned forced outage rates. Given the exceptional nature of this unavailability, the decision was made to analyse such events as a sensitivity instead (see chapter 6.2).

The analysis of the forced outage rates of Belgian production units has shown that the outage rate can differ greatly between years. In Figure 36 and Figure 37, this variability is illustrated for the CCGT and nuclear production units respectively. It can be observed 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.

FORCED OUTAGE RATE FOR BELGIAN CCGT POWER PLANTS PER YEAR (FIG. 36)



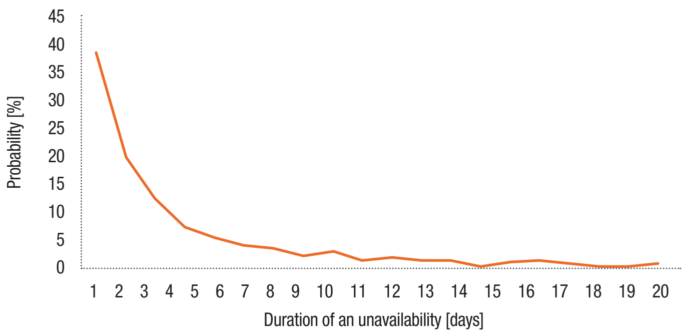
FORCED OUTAGE RATE FOR BELGIAN NUCLEAR POWER PLANTS PER YEAR (FIG. 37)



In addition to the analysis regarding the frequency at which unplanned outages happen, the length of these outages for Belgian production units was also studied. For unavailability with 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 in the calculation of the necessary volume of strategic reserve.

For each production unit type, the probability associated with the duration of an unplanned unavailability was modelled separately. The analysis of the historical length of the forced outages shows that unavailability of a limited number of days is more common. However, unplanned unavailability of longer duration can also occur, as illustrated in Figure 38 ('Duration of an unavailability' refers to number of days).

EXAMPLE: DISTRIBUTION OF THE DURATION OF AN UNAVAILABILITY FOR ONE TYPE OF PRODUCTION UNITS (BASED ON THE ANALYSIS OF HISTORICAL DATA) (FIG. 38)



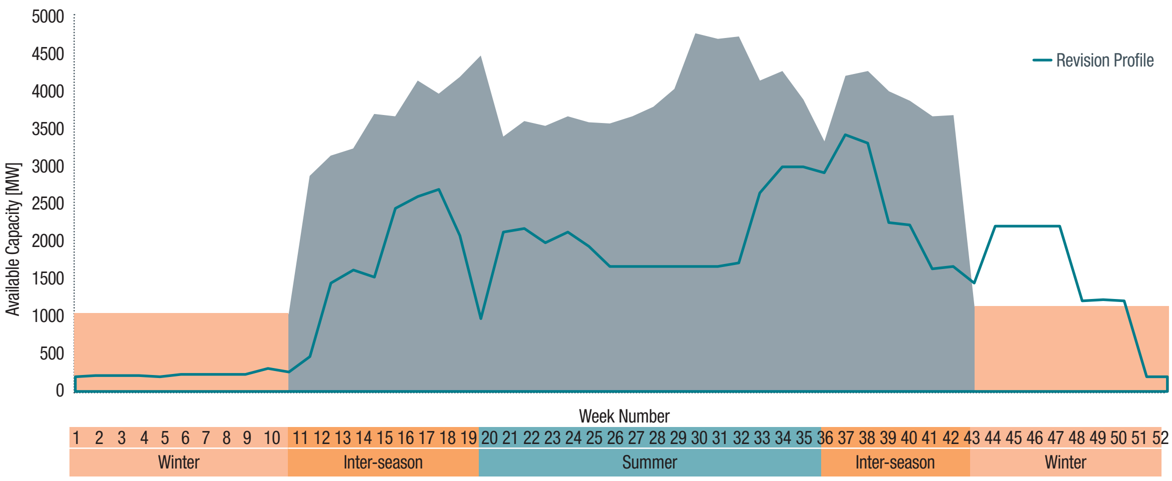
METHOD AND HYPOTHESES USED FOR CALCULATING OF THE OPTIMAL MAINTENANCE CURVE

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

- The **optimal 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 strategic reserve volume, but modified to cover a complete calendar year.
- The TSO's acceptance or refusal of a maintenance schedule submitted by the BRP is determined by the risk of shortage. The risk of shortage is evaluated by comparing two parameters: the volume available for maintenance (VP95) and the volume for maintenance as proposed by the BRP (VR). When there is a small risk of shortage (VR < VP95, with only one-off risk of shortage), Elia will ask the BRP to modify their maintenance schedule in order to minimise the punctual risks. In the second case, when VR > VP95 and thus a high risk of shortage is identified, Elia will ask the BRP 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 BRP in question.

By way of illustration, Figure 39 shows the result of the abovementioned exercise for 2018. The orange area shows the optimal maintenance curve, with the solid line indicating the scheduled maintenance planning at the moment. A punctual risk of shortage is visible between weeks 43 and 48. Therefore, modifications in the maintenance schedule are being discussed with the BRPs.

WEEKLY AVAILABLE CAPACITY FOR ARP REVISION PLANNING (FIG. 39)



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 Platte Taille power station. The total installed turbining capacity is 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 thus 5300 MWh.

In the ANTARES model, the ten Belgian pumped-storage units are modelled individually, making it possible to take into account planned and forced outages on these units. The model determines the dispatching of the units using a daily cycle, taking into account the hourly electricity price (optimal economic dispatch, see section 8.2). 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 to Belgian electricity production. The historical use of pumped-storage power plants in Belgium is in line with the model results.

When the model encounters periods of structural supply shortage (with prices of up to 3000 €/MWh), the pumped-storage units will be used at maximum capacity. If the supply shortage lasts for longer periods of time, the model will dispatch the pumped-storage units in order to flatten peaks in the electricity use.

Run-of-river power stations in Belgium have an installed capacity of 114 MW. For informative purposes, Figure 40 shows the geographical distribution of this production type at the end of 2016. According to the information available to Elia, a very slight increase of this capacity is expected, resulting in an installed capacity of 120 MW at the end of 2020. As described in greater detail in section 8.1.2.4, the run-of-river power stations are taken into account in the model by using monthly historical profiles for 33 winters.

GEOGRAPHICAL DISTRIBUTION OF THE BELGIAN RUN-OF-RIVER ELECTRICITY PRODUCTION (WINTER 2017-18) (FIG. 40)

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

3.1.5. BALANCING RESERVES

In 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. These ancillary services, also called balancing reserves, are agreements with certain producers and consumers to increase or decrease production or demand by 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 by, *inter alia*, 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 of the strategic reserve, the volume production capacity contracted for frequency containment reserves (FCR) and frequency restoration reserves (FRR) is taken into account in the simulations as a reduction of available capacity to cope with adequacy. A slight decrease in the volume of balancing reserves for Belgian production units taken into account for winter 2018-19 in this study (based on the needed volume for 2018) in comparison to the value used in the previous study for winter 2017-18 (based on the necessary capacity for 2017).

The amount of balancing reserves needed for 2018 was proposed by Elia and approved by the Belgian regulator CREG. The approval document can be found on CREG's website [28].

FCR – Frequency Containment Reserve ('primary reserve'):

The objective of primary frequency control is to maintain the balance between generation and consumption within the European interconnected high-voltage system. This reserve is defined at ENTSO-E level for the European synchronous area. At the time of writing, this figure is not yet known for 2018. It is thus assumed in this study that it will be around 80 MW. Since part has been contracted on demand since mid-2016, FCR can also be contracted abroad; 20 MW of FCR is considered as being sourced on Belgian production units from 2018 onwards.

aFRR – automatic Frequency Restoration Reserve ('secondary reserve'):

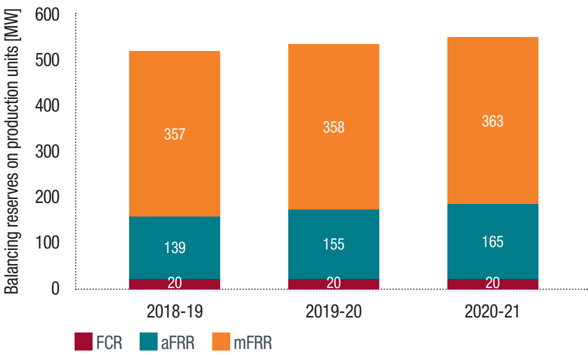
For winter 2018-19, it is assumed that 139 MW will be provided by Belgian production units. Given the specific requirements of this reserve, this type of reserve is mainly provided by production units.

mFRR – manual Frequency Restoration Reserve ('tertiary reserve'):

Tertiary reserve products can be provided either by demand or production. The volume considered reserved for Belgian production units in this study is 357 MW for winter 2018-19.

For illustration purposes, Figure 41 shows the balancing reserves considered as provided by Belgian production units for this study per type of reserve. More information about these types of reserves can be found on Elia's website [23].

BALANCING RESERVES CONSIDERED AS PROVIDED BY BELGIAN PRODUCTION UNITS IN THIS STUDY (FIG. 41)



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 possible measures to be taken if there is a risk to security of supply, see section 1.4.3.

ELECTRICITY CONSUMPTION IN BELGIUM

As discussed in greater detail in the appendix in 8.1.3, modelling electricity consumption consists of three steps (see Figure 42). In this section, the assumptions taken for Belgium in each of these three steps are given.

STEPS TO CONSTRUCT CONSUMPTION PROFILE (FIG. 42)

1. GROWTH OF THE TOTAL DEMAND
2. GROWTH APPLIED TO AN HOURLY PROFILE NORMALISED FOR TEMPERATURE
3. ADDITION OF THE TEMPERATURE SENSITIVITY EFFECT TO THE NORMALISED LOAD

This section provides an overview of the assumptions made with regard to Belgian electricity consumption. The modelling details are provided in the appendix in 8.1.3.

What is total electrical consumption (‘Total load’)?

Total electrical consumption takes into account all loads on the Elia and 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 with Elia consumption (‘Elia grid load’)?

The Elia grid load is a calculation based on injections of electrical energy into the Elia grid. It incorporates the measured net generation of (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 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 under 30 kV into the distribution networks is not entirely included in the Elia grid load. The significance of this last segment has steadily increased during the last years. Therefore Elia decided to complete its publication with a forecast of the total Belgian electrical load.

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

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

The Elia grid includes grids with voltages of at least 30kV in Belgium but also in the Sotel/Twinerg grid in the south of Luxembourg. In this study, Belgium’s Total load does not include the consumption of the Sotel/Twinerg grid. This 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 [25].

3.2.1. GROWTH OF TOTAL BELGIAN LOAD

1 GROWTH OF THE TOTAL DEMAND

For Belgium, the most recent forecast by IHS Markit, a consultancy, is taken as reference for total Belgian electricity demand in this study. This forecast takes into account IHS Markit research on the underlying economic and policy drivers that affect the European power markets up to June 2017. The IHS Markit forecast is based on a top-down model (e.g. using parameters such as GDP). A relatively small average growth of 0.5% is considered for this study.

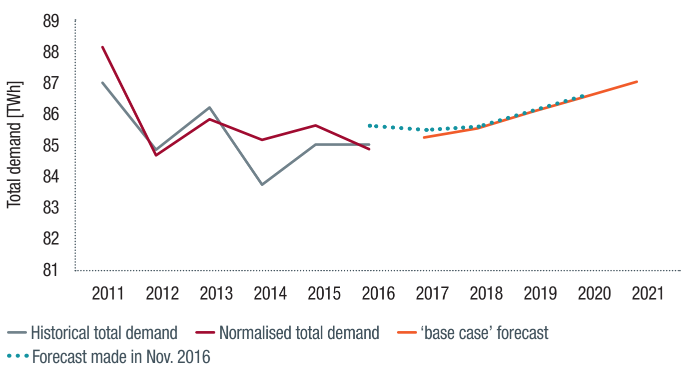
Figure 43 gives an overview of annual total demand since 2011 and its value normalised for temperature. The table includes the 'base case' forecast used for this analysis as well as the 'base case' forecast used in the previous study in November 2016.

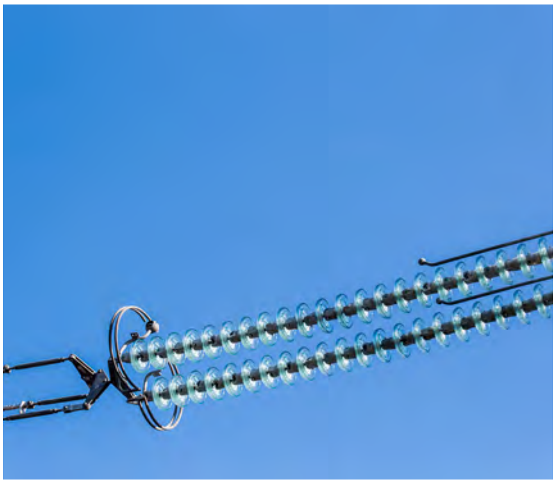
OVERVIEW OF THE YEARLY TOTAL DEMAND SINCE 2011 AND ITS NORMALISATION FOR TEMPERATURE (FIG. 43)

		Historical values			'Base case' normalised total demand		Forecast Nov. 2016
		Total demand (TWh)	Normalised total demand (TWh)	Growth rate	Growth rate	Forecast (TWh)	Forecast (TWh)
historical	2011	87.02	88.17	-0.01			
historical	2012	84.86	84.66	-3.97%			
historical	2013	86.24	85.81	1.36%			
historical	2014	83.73	85.14	-0.78%			
historical	2015	85.01	85.64	0.58%			
historical	2016	85.02	84.86	-0.91%			85.64
forecast	2017				0.44%	85.23	85.50
forecast	2018				0.33%	85.51	85.60
forecast	2019				0.65%	86.07	86.08
forecast	2020				0.56%	86.55	86.60
forecast	2021				0.60%	87.07	

The values shown in the table of Figure 43 are also plotted in Figure 44. Given the fact that the year 2015 was warmer than average, it leads to a normalised consumption for 2015 that is higher than the historical observed value. As 2016 was slightly colder than average, the inverse effect can be observed.

TOTAL BELGIAN HISTORICAL DEMAND AND FORECAST OF THE NORMALISED DEMAND (FIG. 44)



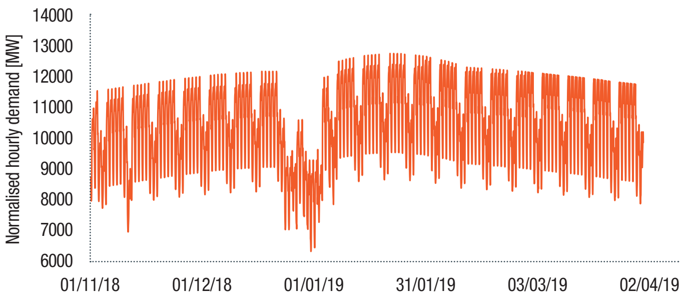


3.2.2. BELGIAN NORMALISED DEMAND PROFILE

2 GROWTH APPLIED TO AN HOURLY NORMALISED PROFILE FOR TEMPERATURE

The normalised profile used in this study was constructed by a dedicated ENTSO-E working group. For the construction of this normalised profile, historical load data is combined with temperature data and information on public holidays. The growth identified in step 1 is applied to this normalised profile in order to match the total forecast demand normalised for temperature. The hourly normalised profile for Belgium used in this study is shown on Figure 45.

HOURLY NORMALISED LOAD PROFILE FOR BELGIUM FOR WINTER 2018-19 (FIG. 45)



From Figure 45 one can clearly see the weekday/weekend effect and the holiday effect on Belgian consumption. 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.

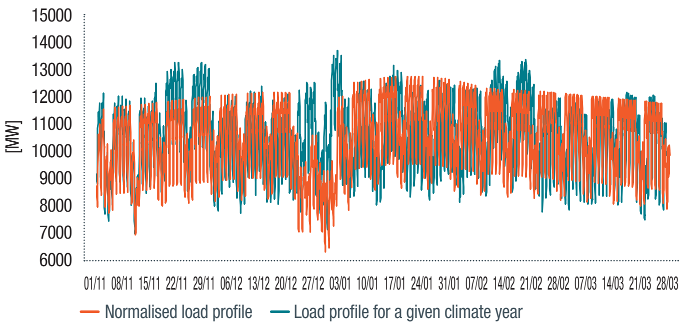
Like the pumped-storage units, the impact of market response is not taken into account in this profile. Market response is modelled separately and is optimised by the model based on the electricity production cost. More information on the Belgian market response, and the new method developed to assess its volume and activation details can be found in section 3.3.

3.2.3. SENSITIVITY OF THE BELGIAN LOAD TO TEMPERATURE

3 ADDITION OF THE TEMPERATURE SENSITIVITY EFFECT TO THE NORMALIZED LOAD

The last step consists of applying the temperature sensitivity to the hourly profile normalised for temperature. For each climate year, an hourly profile for consumption is created. Figure 46 shows the impact of temperature on the total hourly profile for Belgium for one of the 33 historical winters used in this study.

EXAMPLE OF A LOAD PROFILE ON WHICH THERMOSENSITIVITY OF THE DEMAND WAS APPLIED COMPARED TO THE NORMALISED PROFILE (FIG. 46)



In the context of the ENTSO-E MAF study (see section 1.8.4), a new methodology for incorporating the temperature sensitivity of the load was developed. This new method relates the daily minimal and maximal power to the daily temperature (average over 24 hours). Furthermore, instead of a linear relationship as used in previous Belgian adequacy studies, a cubic relationship is used which makes it possible to capture in a systematic way effects like saturation, while preserving the level of accuracy of the linear method previously used. More details of this method are given in section 8.1.3.3.

Elia has chosen to implement this new method, developed in the context of ENTSO-E, for the analysis of winter 2018-19. This choice is made in order to increase the methodological consistency between the volume determination of strategic reserve assessment and the methods developed and used at the European level within ENTSO-E.

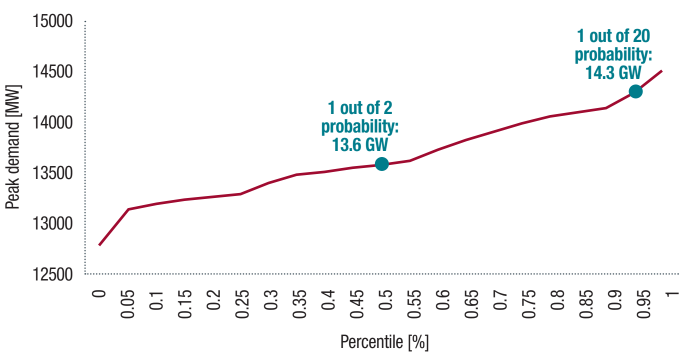
FORECAST OF THE PEAK DEMAND IN BELGIUM FOR WINTER 2018-19

Figure 47 gives an overview of peak demand after applying the thermo-sensitivity effect for the 33 winters used in this study to the Belgian normalised profile. The peak demand thus shown is the maximum demand observed for a given winter. Although this figure gives an indication of the maximum load observed among the different historical winters used, it does not show the occurrence of high demand values within the winters.

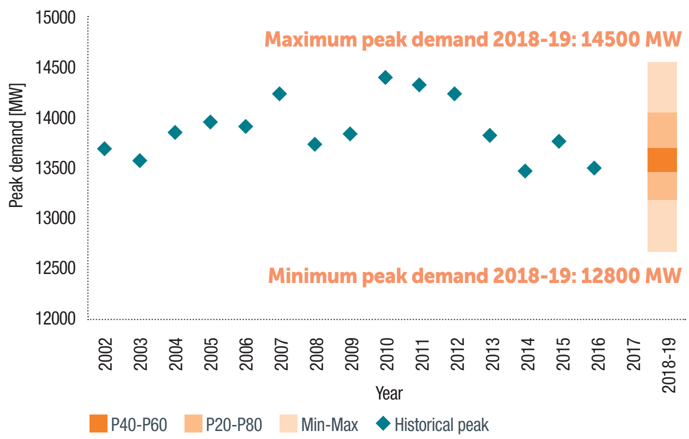
During the winter period more than one cold spell could be observed, the length of those being a very important parameter for adequacy problems. If the high demand is observed for only a few days, it will have a lower impact than if a cold spell lasts two weeks. From Figure 47 a peak demand of 13.6 GW can be observed for the 50th percentile for winter 2018-19 under study (probability of 'once every two years'). In extreme cases, peak demand could be even higher as shown by the 1 out of 20 probability (95th percentile, probability of 'once every twenty years') that equals 14.3 GW.

Figure 48 shows the historical peak demands[29] since 2002. Note that peak demand is not constant and is mainly influenced by the temperature. The graphic also shows the probability percentiles for peak demand in winter 2018-19 as used in this analysis, whose range covers the observed historical peak demands.

PEAK LOAD DISTRIBUTION FOR THE 33 CLIMATIC WINTERS FOR BELGIUM FOR THE WINTER 2018-19 (FIG. 47)



HISTORICAL PEAK LOADS IN BELGIUM AND FORECAST FOR 2018-19 (FIG. 48)



Peak demand for winter 2018-19 is forecast between 12.8 GW and 14.5 GW depending on climatic conditions.

29. Historical peak demand is an estimate based on measurements and calculations.

MARKET RESPONSE IN BELGIUM

This section discusses how available Belgian market response is taken into account in this adequacy study. As consumers may react during periods of scarcity by reducing their net consumption, it is important to take this response into account to avoid oversizing the strategic reserve needs. Section 3.3.1 gives a short overview of the ways in which the market response has been integrated in the past, and of the process followed for the development of the new method to correctly integrate market response into the process of determining the volume of strategic reserve. Next, in section 3.3.2 a detailed description of the newly developed method is given, together with the results obtained.

3.3.1. INTRODUCTION

Market response is a crucial market dynamic during difficult situations on the electricity grid, especially under tough conditions, when adequacy problems arise. European (2009/72/CE and 2012/27/CE) and national policy makers as well as regulators are pushing for the increased development of 'Demand Side Response' (DSR) and 'Market Response' (MR). This effort is mirrored by market stakeholders' demands (FRP, BRP, producers, suppliers, third party aggregators and customers) to fine-tune the methodology used to identify the volume of market response[30] in Belgium in the context of determining the volume of the strategic reserve.

In 2015, Elia sent a questionnaire to the BRPs, Elia grid users and/or aggregators to estimate market response at times of system stress. 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. The results focused 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.

During the public consultation held in 2016 the request was made to update the market response data for winter 2017-18. Due to timing constraints the decision was made to update the study performed in 2015. Consequently, this involved only re-using the existing templates and leveraging respondents' experience, but without addressing the approach itself. However, it was decided that for future volume assessments the methodology to assess the market response volume should be improved and/or changed.

30. In general, DSR is seen as the reduction of consumption (not including distributed generation or storage technologies), while market response should be understood in a broader sense, leaving out the technology (including distributed generation or storage technologies). In this sense, it is the market response which is investigated as an input for this Adequacy Study.

In 2017, a broad range of market players expressed their willingness to be involved in the development of a new methodology to determine market response in Belgium within the scope of the process for determining the volume of the strategic reserve. In the context of the Task Force 'implementation Strategic Reserve', a 'Demand Response Study' subgroup was created in January 2017 to design the most appropriate methodology for determining these market response volumes. This study was conducted in cooperation with E-CUBE Strategy Consultants. The methodology was designed on the basis of interactions with stakeholders over the course of four workshops and bilateral interviews.

3.3.2. DEVELOPMENT OF A NEW METHOD TO DETERMINE THE VOLUME OF MARKET RESPONSE

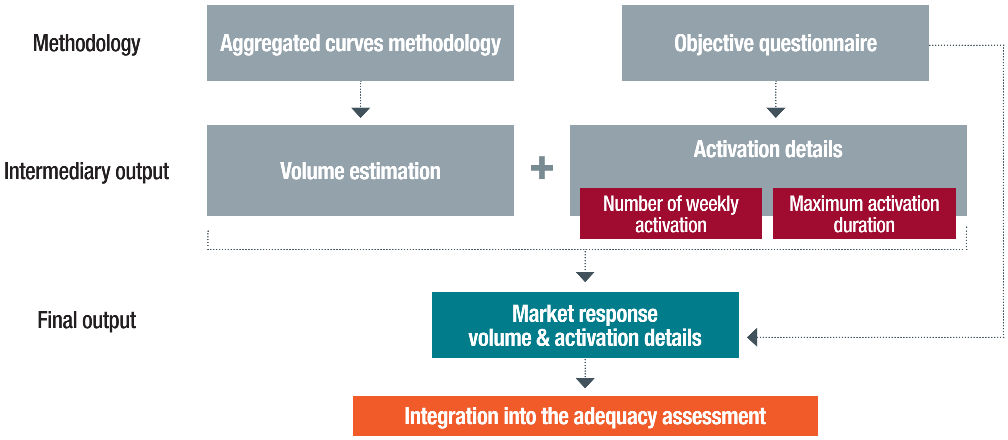
Market response, as used in the context of determining the volume of the strategic reserve, encompasses the full market response in the energy-only market to extraordinarily high prices. Market response under normal price conditions (prices < 150 €/MWh) is already considered in the normalised load profile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

Based on the workshops and input from consultants, it was concluded that the entire available market response can be taken into account with the following threefold approach (as shown in Figure 49): global market response volumes can be estimated based on the analysis of the aggregated demand and supply curve[31] of the EPEX Spot Belgium day-ahead market (section 3.3.2.1). This analysis was supplemented with a qualitative questionnaire (section 3.3.2.2) to assess the activation details and lastly was verified with a sanity check (section 3.3.2.3).

The results of the analysis and how these should be integrated in the adequacy assessment are summarised in section 3.3.3. The methodological framework can be considered robust for the coming years, though some analysis could be updated regularly as reflected in section 3.3.4. The final reports of this study are available on Elia's website [61] and [62].

31. An aggregated curve is a curve representing all the demand offers, expressed in capacity, ranked from lower to higher price.

INTEGRATION OF THE METHODOLOGY INTO THE ADEQUACY ASSESSMENT (FIG. 49)



3.3.2.1. AGGREGATED-CURVES ANALYSIS: ESTIMATING GLOBAL VOLUME

The aggregated-curves methodology makes it possible to estimate the total market response volume for the contract-based, price-based market response and voluntary market response categories. In the aggregated curves, market response volumes can be valued as a demand decrease or as a supply increase.

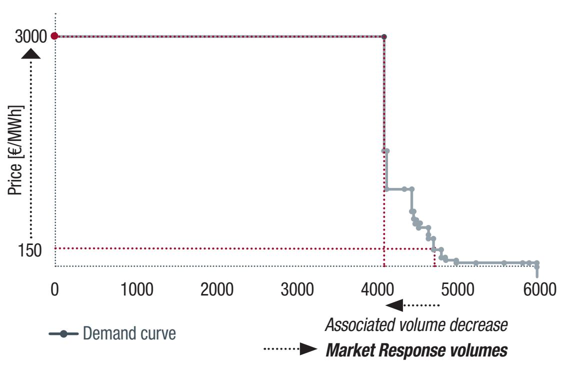
The demand decrease due to a price increase is directly present in the aggregated curves by studying the volume decrease associated to the price increase from 150 €/MWh (bottom price limit of the market response volumes) to 3000 €/MWh (maximum day-ahead price) as can be seen in Figure 50. Since the aggregated curves are provided for each hour, this volume comparison is computed hourly.

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

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

Instead of a demand decrease, suppliers can value market response as a supply increase in the market. It is not possible to deduct market response directly from these curves as they aggregate this capacity with generation. Contrary to the demand curves where the presence of bids representing generation reductions is considered very limited above 150 €/MWh, the supply curves can contain generation bids of these price orders. Generation bids higher than 150 €/MWh can be justified by extraordinary variable costs such as foreign sourcing.

MARKET RESPONSE IN THE DEMAND CURVE (FIG. 50)



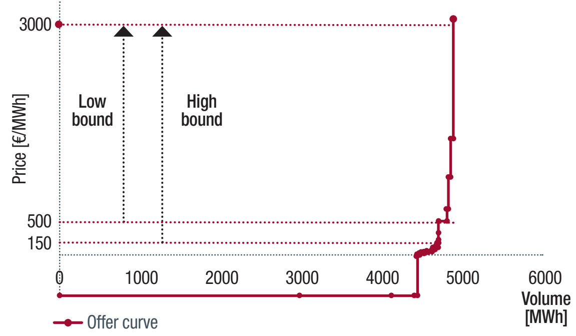
To refine the analysis of the supply curve, two price thresholds are considered (see Figure 51):

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

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

- a low estimate of the supply side: this estimate does not take into account the potential value under 500 €/MWh but definitely excludes generation;
- a high estimate: this estimate integrates the adequate market response perimeter but possibly takes into account additional volumes of generation assets.

ANALYSIS OF THE AGGREGATED-SUPPLY CURVE (FIG. 51)



In the aggregated curves, the smart orders[32] are not taken into account. This could reduce the total market response volume estimated. However, the volumes of market response smart orders are very limited, most of it being from generation assets. The impact on market response volumes assessment is very limited.

Over The Counter (OTC) bids are implicitly taken into account in the curves. If not in the curves, it would correspond to irrational behaviour by the stakeholders, which was not taken into account in the study.

As an example, if the volume above 150 €/MWh is 150 MW and if the volume above 500 €/MWh is 100 MW, the volumes of market response valued in the supply curve can be considered to be in the [100-150] MW range.

The output volume of the methodology corresponds to the adapted scope for the contractbased and pricebased market response categories, but also the voluntary market response forecast by the market players. If there are some volumes in the voluntary market response category, the market players will anticipate such events. In theory, their anticipation will be reflected in their bidding behaviours if they are considered firm by the BRPs, with the voluntary market response then implicitly taken into account in this methodology. In general, this approach makes the methodology robust towards future changes (e.g. new technologies facilitating market response) as any change which is and will be considered firm by the market players will appear in the aggregated curves, and will therefore be considered in the analysis.

3.3.2.2. 'OBJECTIVE QUALITATIVE Q&A': QUALITATIVE CONTENT TO COMPLEMENT THE AGGREGATED-CURVES ANALYSIS

The aggregated-curves analysis provides a capacity estimate and not an hourly volume to integrate in the model. For integration into Elia's adequacy assessment, the number of activations per week and the maximum activation duration must be obtained.

The activation details are obtained by means of a Q&A. This questionnaire was factual, so as to avoid unrealistic and unanswerable questions. It was also qualitative, focusing on gathering the required activation information in order to establish a correct link between adequacy and the methodology, i.e. the activation details.

According to the discussion conducted with the stakeholders, the Q&A needed to be simple, intuitive, and have questions anchored in reality. Its main objective was to obtain high-quality information to complement the aggregated-curves methodology: the key information being the number of possible activation per week and the duration of the activation.

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

3.3.2.3. GLOBAL SANITY CHECK

To conduct a sanity check, the questionnaire also provided an estimate of the volumes currently valued. This made it possible to avoid the main limit of the questionnaire raised by the stakeholders: the hypothetical situation description.

An international benchmarking was conducted, putting the market response volumes in proportion to the maximum peak load in the electric system.

These volumes were then compared to the volumes previously established so as to assess the global consistency of the volumes.

32. Smart orders are linked block orders (one block is executed if the other is) or exclusive block orders.

3.3.3. RESULTS OF THE ANALYSIS AND INTEGRATION IN THE ADEQUACY ASSESSMENT

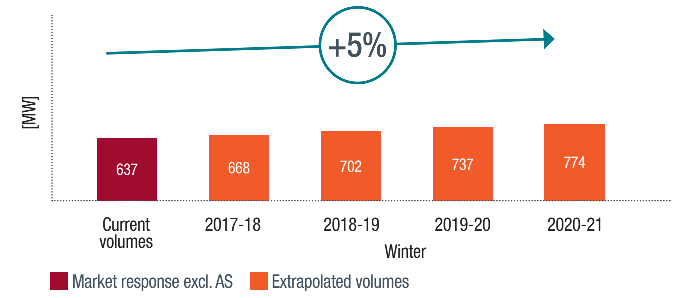
The aggregated-curves analysis firstly made it possible to estimate market response volumes. The volumes had to be extracted first from the EPEX Spot Belgium day-ahead market aggregated curves so as to obtain a treatable dataset of market response hourly values from 01/01/2014 to 01/05/2017. On the demand side, market response volumes can be directly found in the aggregateddemand curve, by studying the decrease in volume when the price increases from 150 €/MWh to 3000 €/MWh (excluding the 'at any price' bids). In the supply curves, the market response is represented by two volumes: market response offered above 150 €/MWh (high bound) and above 500 €/MWh (low bound).

The dataset was then refined, firstly by excluding the national strike and treating the national holidays as Sundays in terms of day type. Secondly, the year 2014 was excluded from the dataset due to a specific bidding behaviour in the supply curves, not corresponding to the current reality of the market. This refined dataset is therefore more accurate while maintaining a satisfactory amount of data.

The refined dataset was then analysed to assess the impact of various parameters on market response volumes, including temperature, price and Elia grid load. Although the regressions did not reveal statistical correlations between the market response volumes and these parameters, another analysis made it possible to ascertain that the Elia grid load has the greatest impact on market response volumes. Indeed, in high-loads periods, the standard deviation of the dataset is reduced and the average volume is increased. Consequently, the volumes for the winter peak hours were extracted as to study highload hours separately. The average volume during winter peak hours for the refined dataset reaches 637 MW.

Finally, the output was extrapolated to the three future winters (i.e. winter 2018-19, 2019-20 and 2020-21). An option to change the extrapolation factor for the market response volumes for the following years was discussed during the Task Force meetings. An extrapolation factor of 1% growth per year, based on historical analysis, together with two alternative extrapolation scenarios of 3% and 5%, were presented. Based on discussions during the Task Force meetings, a 5% yearly growth was put forward, subject to a yearly reassessment based on an update of the quantitative analysis. The values that will be integrated in the adequacy study are shown in Figure 52:

MARKET RESPONSE VOLUMES EXTRAPOLATION (FIG. 52)



To be useful for this adequacy study, the output of the aggregated-curves analysis was supplemented with the activation constraints: number of weekly activations and maximum activation duration. This qualitative information was provided by the questionnaire sent to all relevant market players, i.e. TSO grid users, BRPs (non-grid users) and aggregators. A satisfactory response rate (81 out of 162 questionnaires sent) made it possible to differentiate seven categories of activation constraints: the majority of the volumes is estimated to provide between 2 to 28 activations per week, and between 1 to 4 hours of maximum activation duration, while 5% of the volumes have no constraints regarding both the number of activation per week and the activation duration.

This categorisation, based on answers from the TSO grid users, was broadly validated by answers from BRPs (non-grid users) and aggregators. Figure 53 gives an overview of the constraints used in the model. This assumption is made on the basis of the analysis of the different responses to the survey.

CATEGORIES OF ACTIVATION CONSTRAINTS (FIG. 53)

Number of activations per week	2	4	7	14	14	28	No limits
Activation duration (hours)	1	4	2	2	4	4	No limits
% of Market Response volumes	~10%	~10%	~25%	~10%	~30%	~10%	~5%

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

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

The third part of the methodology consisted of verifying the consistency of the results with a sanity check. Firstly, in addition to the qualitative information, the questionnaire respondent also provided quantitative feedback on the market response volume available. This volume is treated very carefully since the individual estimate cannot be extrapolated as such to provide an objective quantification of the total market response volume. However, this sanity check made it possible to validate the order of magnitude of the volumes with an estimated market response range of [560 – 690] MW. The qualitative feedback from the questionnaire also made it possible to validate the winter peak hours categorisation. Secondly, the volumes were compared to the available market response information in the benchmarked countries. In the UK, an estimate of market response is provided by the Triad Avoidance mechanism: these volumes represent 4% of the UK's peak load, which is coherent with the 5% found for Belgium (market response, excluding ancillary services). Similarly, a consistency check was conducted for France and PJM, yet on a total market response level (including Ancillary Services). The total market response estimate for Belgium is above the values for France and PJM.

3.3.4. UPDATE OF THE METHODOLOGY

To take into account future changes in the market response volumes, its implementation in order to obtain representative results could be updated regularly. However, the methodological framework itself, defined together with the market parties, can be considered robust for future years.

The quantitative method facilitates an annual re-calculation based on updating the data and parameters, without needing to re-design the methodology annually. The EPEX Spot Belgium day-ahead market aggregated curves should be updated with recent data every year, along with price thresholds, the extrapolation factor and ancillary service changes. Note that new market changes impacting the aggregated curves will be automatically incorporated in the analysis.

The qualitative methodology, however, is less sensitive to yearly changes while being more resource intensive for Elia and market parties. An update of the qualitative aspects could be planned after a few years or whenever the need becomes apparent.

3.4 SUMMARY OF ELECTRICITY SUPPLY AND CONSUMPTION IN BELGIUM

Figure 54 summarises the forecast 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.

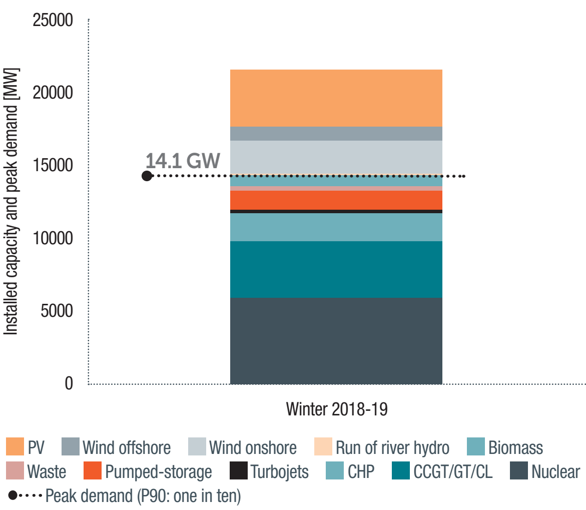
Note that this installed capacity does not take into account forced nor planned outages or energy limitations of some technologies.

INSTALLED GENERATION CAPACITY IN THE MARKET (EXCLUDING UNITS IN STRATEGIC RESERVE) (FIG. 54)

		Production capacity in winter available in the market (MW)				
		2016-17	2017-18	2018-19	2019-20	2020-21
Non RES	Nuclear	5919	5919	5919	5919	5919
	CCGT/GT/CL	4006	3846	3846	3776	3776
	CHP	1990	1835	1955	1826	1786
	Turbojets	158	158	158	68	68
Storage	Pumped-storage	1308	1308	1308	1308	1308
RES	Waste	331	331	331	331	331
	Biomass	844	794	811	840	874
	Run of river hydro	114	114	114	117	120
	Wind onshore	1580	1915	2165	2414	2663
	Wind offshore	712	859	1051	1576	2205
	PV	3101	3526	3881	4356	4966
	Total	**20063**	**20605**	**21539**	**22531**	**24016**

Figure 55 can be constructed by combining the installed generation capacity with the P90 peak demand forecast in Belgium for winter 2018-19. In addition to these capacities, market response when prices are high should be considered together with the respective activation limits, see section 3.3 for more information. Similarly, any possible imports (see chapter 5 for detailed information) are not shown on this figure. Moreover, it should be noted that comparing the shown P90 peak demand with the installed capacity does not give any indication regarding adequacy. Indeed, the availability of generation and exact distribution of demand have to be correctly taken into account when analysing the Belgian adequacy.

INSTALLED GENERATION CAPACITY IN THE MARKET AND P90 PEAK DEMAND IN BELGIUM FOR WINTER 2018-19 (FIG. 55)



04

ASSUMPTIONS FOR NEIGHBOURING COUNTRIES

Given the high amount of possible energy exchanges between countries, accurate modelling of foreign countries is crucial in order to quantify structural shortage hours in Belgium. In order to achieve this, the data and assumptions for neighbouring countries are collected through bilateral contacts with the respective TSOs. For those 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 1.8.

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.

FRANCE

The thermal and nuclear capacity is assumed to remain stable for the next three winters in line with recent announcements by the new French government .

Over the past several years, stabilisation of demand in France is observed mainly due to energy efficiency measures and moderate economic growth. It is expected that demand will slightly decrease for the next coming winters.

High nuclear unavailability was observed before and during the winter 2016-17. Reduced availability of some nuclear plants is also possible for parts of winter 2017-18.

An analysis of the observed nuclear availability of the last five winters in France was performed in order to define a sensitivity scenario considered in this assessment.

The French 'Energy Transition' law of 2016 proposed decreasing the share of nuclear energy in electricity generation to 50% by 2025. At the same time, for 2030, the same law also set the goal of ensuring that renewables account for with 40% of the energy mix, driven mainly by the development of wind and solar technologies. Lastly, the law calls for coal-fired power plants to shut down by 2023-25. This law has been the main driver for French energy policies in the last year and a half.

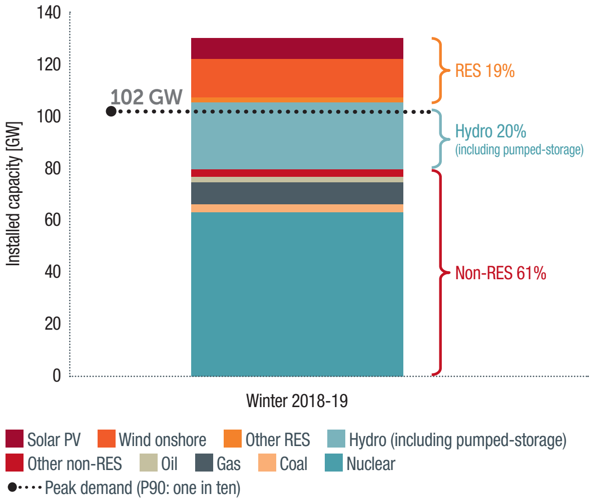
In a recent announcement, the new French government postponed the above mentioned goal of reducing share of nuclear energy in electricity generation to 50% by 2025. According to arguments put forward by the French government, this target is no longer 'realistic for France and that would increase CO_2 emissions, endanger security of supply and put jobs at risk' [35].

An adequacy report ('Bilan Prévisionnel') issued by the French transmission system operator (RTE) was recently published [33]. The RTE report covers two timeframes: 2018-22 and 2022-35.

The period 2018-22 aims to identify the possibilities for taking action on the electricity mix with regard to the objectives defined by the above-mentioned 'Energy Transition' and/or the recent announcements by the French public authorities. There is a particular focus on closing coal-fired power plants and shutting down the first nuclear reactors after 40 years of operation; an overview of the adequacy situation is also provided. The period 2022-35 considers five scenarios examined to define different energy transition options for renewable energies, nuclear power, the carbon footprint and the role of new technologies and means of production.

For this French adequacy report, RTE uses the same probabilistic method and model as used by Elia in this study to simulate the European electricity market. Data mentioned in this section are consistent with the trends presented in the French report [33] for the period 2018-22. Figure 56 gives an overview of installed capacity in France for winter 2018-19 in the 'base case'. P90 peak demand is also indicated in the chart.

INSTALLED CAPACITY CONSIDERED IN THE 'BASE CASE' AND P90 PEAK DEMAND FOR WINTER 2018-19 IN FRANCE (FIG. 56)



4.1.1. ELECTRICITY SUPPLY IN FRANCE

CHANGE IN THERMAL CAPACITY (EXCLUDING NUCLEAR)

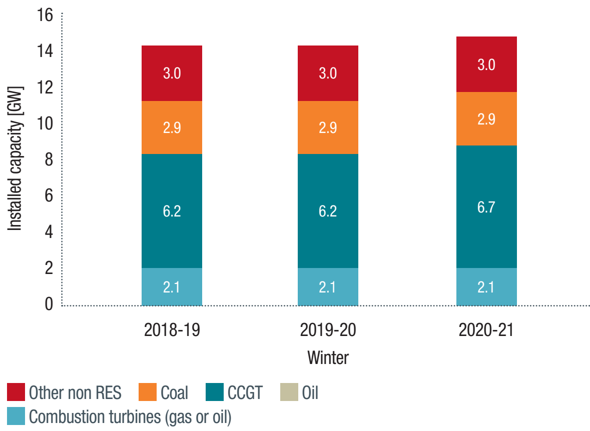
In the 'base case' scenario, the following assumptions are made with regard to the change in installed thermal capacity (nuclear assumptions are detailed below):

- all CCGT units are considered operational for all winters in the assessment;
- coal units are considered to still be in the market (see 'carbon tax' below);
- decentralised thermal generation is considered in the market;
- decommissioning of all fuel oil-fired plants occurs by winter 2018-19.

The **'carbon tax'** in France seems to have been abandoned by the French government, at least temporarily. Therefore no removal of coal capacity has been considered for France in the 'base case' for the three winters in question.

The thermal generation 'base case' (excluding nuclear) is shown in Figure 57 below.

INSTALLED CAPACITY CONSIDERED FOR THE 'BASE CASE' FOR THE FRENCH PRODUCTION PARK (EXCLUDING NUCLEAR) (FIG. 57)

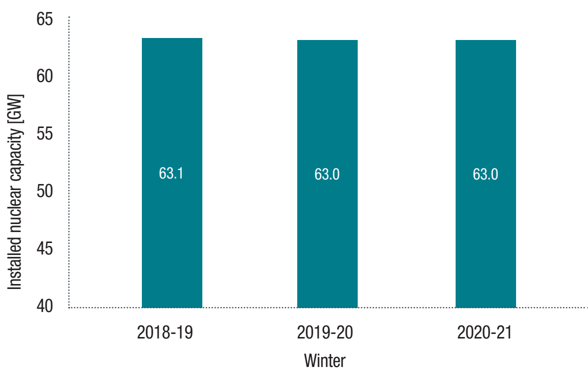


CHANGE IN NUCLEAR INSTALLED CAPACITY

There remain uncertainties about future nuclear generation given the abovementioned announcement by the new French government [35]. However, it is assumed that no significant reduction in French installed capacity is foreseen for the time-frame considered in this study.

There is 63.1 GW of nuclear installed capacity in France, divided across 19 sites around the country. A stable level of 63.1 GW of nuclear capacity is considered in the 'base case' assumptions made for the next three winters, as shown in Figure 58. The new EPR[33] 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 as of that period.

INSTALLED NUCLEAR CAPACITY CONSIDERED IN FRANCE FOR THE 'BASE CASE' (FIG. 58)



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

FRANCE POSTPONES TARGET FOR CUTTING NUCLEAR SHARE OF POWER PRODUCTION [35]

Source: REUTERS – 7 November 2017

The French government has postponed a long-held target to reduce the share of nuclear energy in the country's power production after grid operator RTE warned it risked supply shortages after 2020 and could miss a goal to curb carbon emissions.

[..]

It was not realistic to cut nuclear energy's share of electricity production to 50 percent by 2025 from 75 percent now and that doing so in a hurry would increase France's CO_2 emissions, endanger the security of power supply and put jobs at risk.

RTE said in its 2017-2035 Electricity Outlook that if France went ahead with plans to simultaneously shut down four 40-year-old nuclear reactors and all its coal-fired plants as planned, there could be risks of power supply shortages.

For this winter, RTE said electricity demand was expected to be stable, although unplanned nuclear reactor outages and a prolonged cold spell could squeeze supply.

EXCEPTIONAL LONG-TERM UNAVAILABILITY OF FRENCH NUCLEAR POWER PLANTS:

Nuclear maintenance is planned for several reasons, which include refuelling units or heavy maintenance works. Given the 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 maintenance, a unit can be stopped due to an unexpected event such as a forced outage or at the request by the Nuclear Safety Agency (ASN) for inspection. This was the case for winter 2016-17 for a large number of units and it is the case now in winter 2017-18 for the four reactors at the Triscastin nuclear power plant.

As of this writing, a number of units are in maintenance in France. Most of these units are expected to be back online by the end of November. Three exceptions are:

- Tricastin 1 (915 MW) with maintenance planned to end on 31 December 2017;
- Fessenheim 2 (880 MW) with maintenance planned to end on 31 January 2018;
- Paluel 2 (1330 MW) with maintenance planned to end on 15 April 2018.

Given the exceptional long-term outages of French nuclear power plants in recent years, an analysis of historical French nuclear availability for the last five winters was conducted. This analysis pinpointed a sensitivity that is detailed in section 6.2.

More information on the current availability of all nuclear units in France can be found here [26].

EDF TO CLOSE TEMPORARILY TRICASTIN NUCLEAR PLANT OVER FLOODING RISK

Source: REUTERS – 28 September 2017

French utility EDF will temporarily shut down all four reactors at its Tricastin nuclear power plant after regulator ASN identified flaws in a canal dike bordering the plant.

ASN said in a statement that while the dikes are being strengthened, there was a risk of flooding which could lead to a major accident at the plant, which is located along the Rhone river in the heart of France's Provence wine and tourism region.

[..]

EDF's four Tricastin reactors have a combined capacity of 3600 megawatts, and their shutdown will add to worries that nuclear-reliant France could face tight power supply in winter after ASN identified other flaws at separate sites.

Since the French government also mentions [35] that 'while there is a delay [..] a clear programme would be put forward on which reactors to close and when', the assumptions made for a stable level of nuclear capacity for winters 2019-20 and 2020-21 should be made with care and might need to be revised in next years' assessment. A reduction in installed nuclear capacity in France could lead to adequacy concerns if no replacement is found and such reduction is accompanied by a coal-phase out, according to RTE [33] (see also 4.1.3).

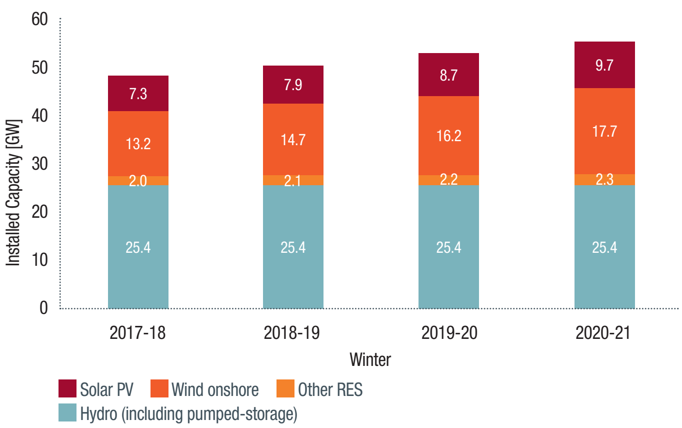
CHANGE IN RENEWABLE ENERGY SOURCES

France has a high volume of hydro installed capacity mainly from big reservoirs in the mountains and run-of-river installations. The pumped-storage turbining capacity is also counted in the hydro installed capacity in Figure 59 below.

The expected change in French renewables is as follows:

- + 1-2 GW/year for the onshore wind;
- + 700-800 MW/year for PV installations;
- + 100 MW/year for biomass units;
- The first French offshore wind farm is expected come online by 2022, so no offshore wind was taken into account in this study for France.

INSTALLED RES AND PUMPED-STORAGE CAPACITY IN FRANCE CONSIDERED FOR THE 'BASE CASE' IN THIS STUDY (FIG. 59)



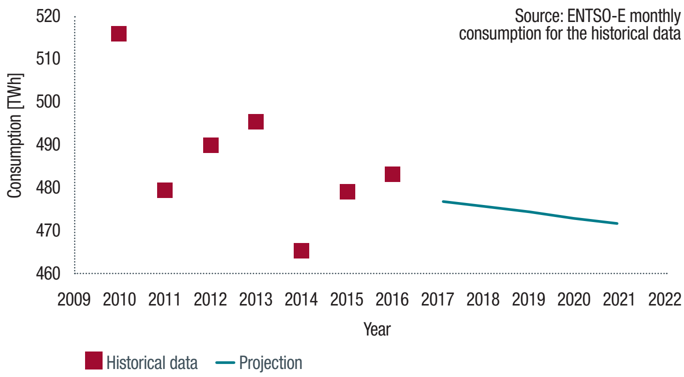
4.1.2. ELECTRICITY DEMAND IN FRANCE

CHANGE IN DEMAND

The historical total demand data are shown in Figure 60. Historical consumption is not normalised for temperature. Meteorological fluctuations are therefore also included. Projected normalised consumption is shown in the figure as well.

Over the past few years, RTE has noted a stabilisation in power demand in France, mainly due to energy efficiency measures and moderate economic growth. These efficiency measures will be further developed in the coming years, so power demand is likely to stabilise or decrease. Peak power demand should follow a similar downward trend. Since 2015, there has been a new legal framework to support new tools for optimising energy consumption in the country and setting ambitious targets to reduce the multi-energy consumption. The input in this paragraph is taken from the country comments provided by French TSO RTE within the PLEF GAA study [60].

DEMAND EVOLUTION IN FRANCE (FIG. 60)



The thermosensitivity of consumption in France is very high. It accounts for around 2400 MW/°C. This is mainly due to the high penetration of electrical heating in the country [36] [37] [38].

After analysing historical load data and data provided by RTE, it was concluded that the method used by Elia in last years' assessment [4] is well suited for modelling the load thermosensitivity for France. Therefore, for the specific case of the French load, this method was used as well in the current analysis. The method used in Elia's last years' assessment is also in line with the method used by RTE in 'Bilan Prévisionnel 2017' [33].

The market response considered for France mainly corresponds to demand-side management of around 2.5 GW.

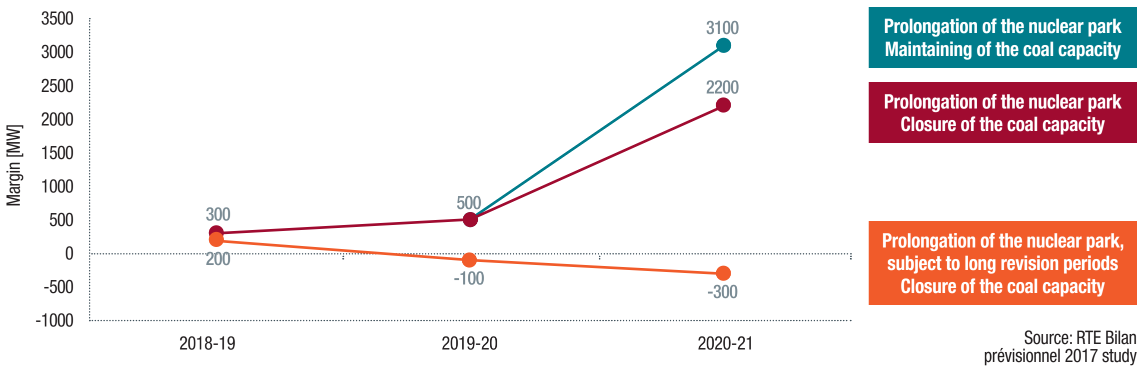
4.1.3. SECURITY OF SUPPLY IN FRANCE

The report by French TSO RTE ('Bilan Prévisionnel') studies the adequacy situation for France [33]. In this report, France presents positive margins and will be within its adequacy standard for the following winters in the following situations:

- Extension of the nuclear fleet, maintenance of coal capacity;
- Extension of the nuclear fleet, closure of coal capacity.

In its report RTE also analyses a situation involving the prolonged closure of nuclear installations. This could, for example, be the case with long-lasting inspections conducted by the ASN. Such a situation involving closures of nuclear power plants for a longer duration, combined with the closure of all coal-fired production capacity could lead to adequacy problems in France according to RTE [33]. An overview of the analysis conducted by RTE is shown in Figure 61 below.

EVALUATION OF THE IMPACT ON ADEQUACY OF LONG REVISION PERIODS (UP TO 12 MONTHS) ON NUCLEAR REACTORS (FIG. 61)



Source: RTE Bilan prévisionnel 2017 study

Furthermore, France has a capacity mechanism. The 1st delivery began on the 1st of January 2017 [71]. The French capacity mechanism is organised as a decentralised capacity market designed to ensure compliance with the reliability criterion set by the French authorities (LOLE of 3 hours per year).

This mechanism is intended to provide a form of insurance: operators are rewarded for the contributions their capacities make to the power system by being available during periods of tight supply. The mechanism is supposed to generate economic signals complementing those generated by the energy market.

The French capacity mechanism is a market-wide mechanism where all participating capacities are allowed to participate in the energy market too. There is a clear separation between the energy market and the capacity market. Indeed, generators that have certified their capacity will only be required to make that capacity available, but will still be able to decide not to produce energy based on the merit order. Consequently, the capacity mechanism is effectively designed not to alter market participants' bidding strategy and dispatch decisions in the short term.

THE NETHERLANDS

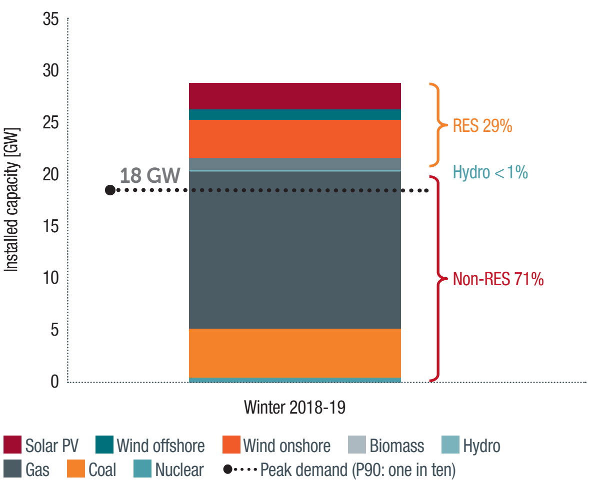
The adequacy report of TenneT published in 2016 indicated that the Netherlands for the first years to come can ensure their required adequacy level solely by relying on domestic power production. At the moment of writing, the TenneT 2017 adequacy report is not published, but we expect a similar trend for winter 2018-19, as one CCGT has returned to the market compared to the assumptions of last year (see details in this chapter below).

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 700 MW HVDC interconnector with Denmark (Cobra cable) is taken into account as of winter 2019-20.

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 2017' [48]. Figure 62 gives the assumptions used for the Dutch electricity supply and demand for winter 2018-19. Sections 4.2.1 and 4.2.2 elaborate on supply and demand in the Netherlands respectively.

INSTALLED CAPACITY AND P90 PEAK DEMAND CONSIDERED IN THE 'BASE CASE' FOR WINTER 2018-19 IN THE NETHERLANDS (FIG. 62)



4.2.1. ELECTRICITY SUPPLY IN THE NETHERLANDS

NON-RENEWABLE ELECTRICITY GENERATION

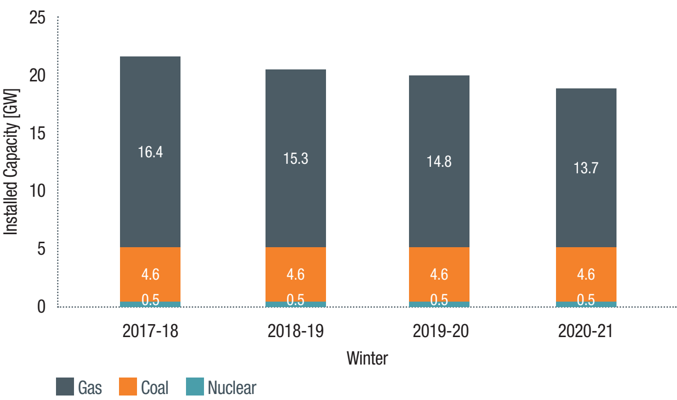
Non-renewable electricity generation in the Netherlands is mainly fuelled by gas and coal; see Figure 63 for the assumptions used in this study. New coal-fired power plants came online in 2014 and 2015, for a total additional installed capacity of approximately 3.4 GW. However, sustainable energy policies have resulted in the closure of five older coal-fired power stations totalling 2.7 GW in 2016 and 2017.

Although the new Dutch government has announced [68] that all other coal-fired power plants should close by 2030, no additional closures of coal-fired power plants are expected until winter 2020-21.

As in other European countries, Dutch gas-fired power plants are facing difficult economic conditions. Several gas-fired plants have announced that they will be temporarily halting operations ('mothballing'). Some of these plants only halt operations during summer ('summer mothballing'), and are thus taken into account in the analysis which concerns only the winter. It is assumed that a total of approximately 5 GW of Dutch gas-fired production units will be 'mothballed' for the entire winter 2018-19. Compared to the forecasts made last year concerning 'mothballed' plants for winter 2018-19, one CCGT (810 MW) has returned to the market. However, it is assumed that 1.6 GW of gas-fired production capacity will close either temporarily or permanently between winter 2018-19 and winter 2020-21.

The Borssele nuclear power plant (installed capacity of approximately 0.5 GW) is the Netherland's 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 considered.

INSTALLED NON-RENEWABLE PRODUCTION IN THE NETHERLANDS CONSIDERED FOR THE 'BASE CASE' IN THIS STUDY (FIG. 63)

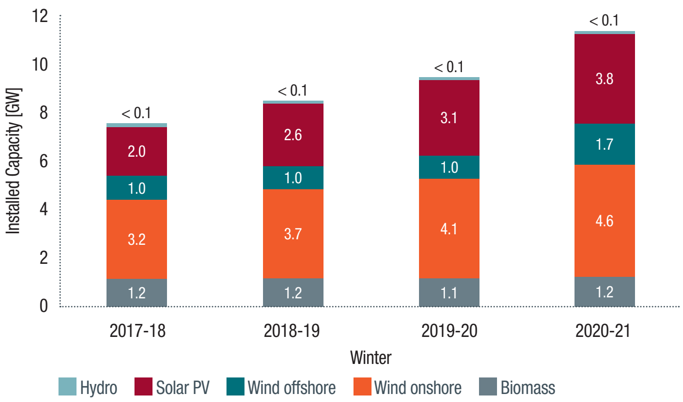


RENEWABLE ELECTRICITY GENERATION

The Dutch national adequacy study bases its forecasts for installed capacity of **renewable** electricity generation on the report entitled 'Nationale EnergieVerkenning 2016' (NEV) [49], a study conducted by the Energy research Centre of the Netherlands (ECN). The assumptions regarding installed capacity of renewables used in this study are shown in Figure 64.

In 2013, the Dutch government approved climate legislation in its 'Energy Agreement for Sustainable Growth' ('Energieakkoord voor duurzame groei') [50]. In this agreement, a goal of 4.5 GW of offshore wind installed capacity is envisaged by 2023, and this is being implemented through a tendering process involving 700 MW per year between 2015 and 2019 [69]. It is assumed that the first 700 MW of additional offshore wind will be online by winter 2020-21. For both PV and onshore wind, an increase of approximately 600 MW is assumed between winter 2017-18 and winter 2018-19. These upward trends continue with a view to winter 2019-20 and winter 2020-21.

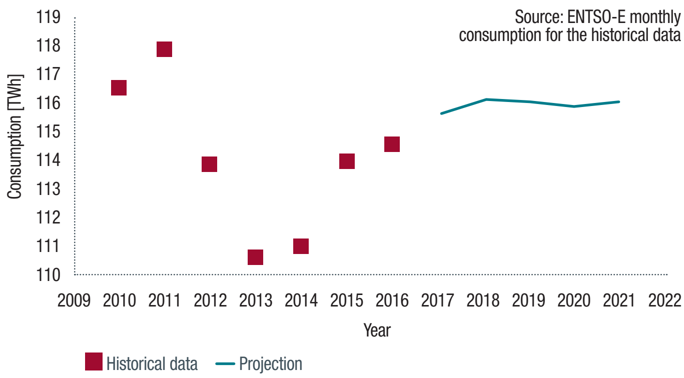
INSTALLED RES AND PUMPED-STORAGE CAPACITY IN THE NETHERLANDS CONSIDERED FOR THE 'BASE CASE' IN THIS STUDY (FIG. 64)

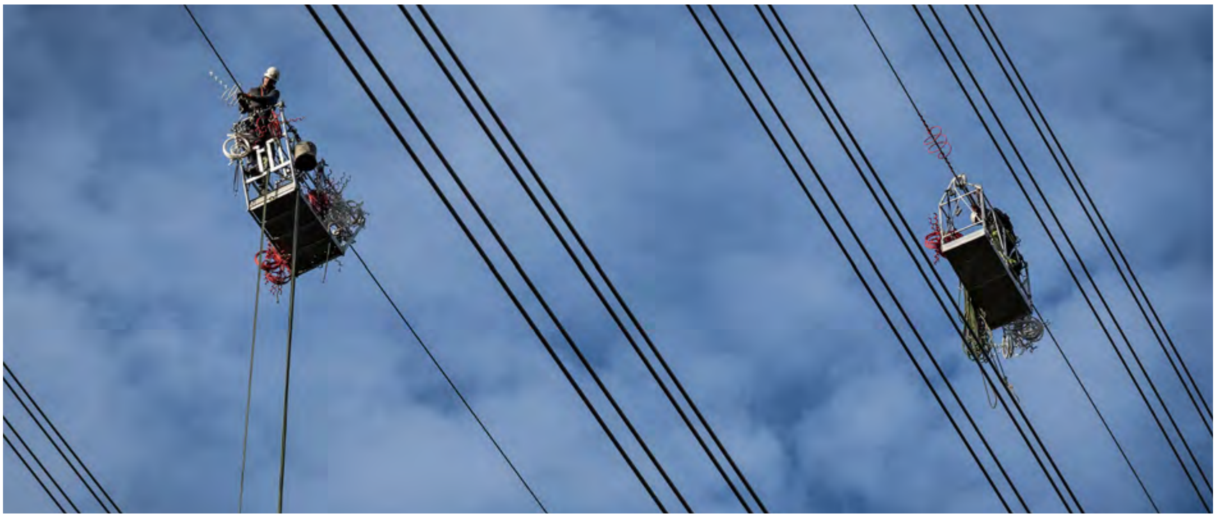


4.2.2. ELECTRICITY DEMAND IN THE NETHERLANDS

The assumptions with regard to electricity demand in the Netherlands are also in line with the Dutch adequacy report. The estimate is made by Dutch transmission system operator TenneT. Figure 65 shows historical Dutch electricity demand (not normalised for temperature), as well as the projection (normalised for temperature) for the coming years. Electricity demand normalised for temperature is expected to remain relatively stable during the period in question. This study does not take into account any potential for **demand-side response** in the Netherlands. This is a conservative assumption made in the absence of better information on this topic.

DEMAND EVOLUTION IN THE NETHERLANDS (FIG. 65)





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 3 GW is expected towards 2020.

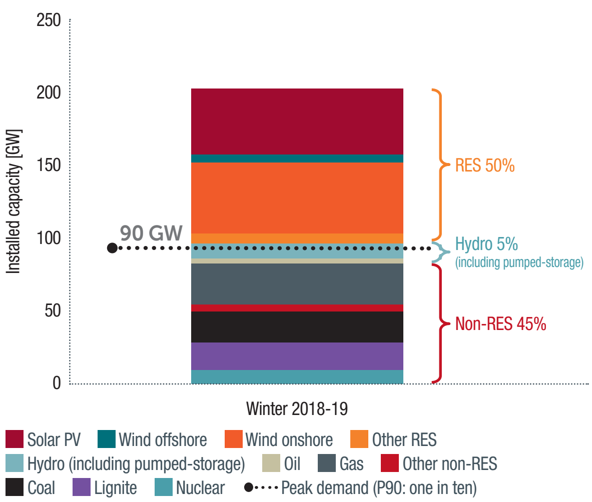
Germany has a comfortable margin when scarcity occurs in Belgium and France because of its large amount of possible imports from the north and the east, and its diversified domestic production park.

A grid reserve ('Netzreserve') of 4,1 GW is contracted up to 2018-19 to ensure grid stability.
A capacity reserve (out of the market) up to 2 GW will probably be tendered in mid 2018 for a time horizon of five years, and should be available in winter 2018-19 for the first time.
The so called 'Security reserve' of 2 GW will consist of lignite power plants in standby that can be called upon last resort.

The 1400 MW Nordlink interconnector is not taken into account out of precaution, since commercial operation for winter 2020-21 is not certain.

The assumptions used in this study for Germany are a compilation of data from the German Ministry of Energy [39], the German Grid Development plan (NEP2016) [40],[41] and bilateral contacts with German TSOs [60]. Figure 66 summarises the supply and demand assumptions for winter 2018-2019. German electricity supply and demand are discussed in greater detail in section 4.3.1 and section 4.3.2 respectively. Lastly, section 4.3.3 elaborates on security of supply in Germany, and the specific measures being considered to ensure it for the coming years.

INSTALLED CAPACITY CONSIDERED IN THE 'BASE CASE' AND PEAK DEMAND FOR WINTER 2018-19 IN GERMANY (FIG. 66)



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 67. It can be seen that the total installed capacity of non-renewable electricity production is expected to drop by approximately 5% over the next four winters.

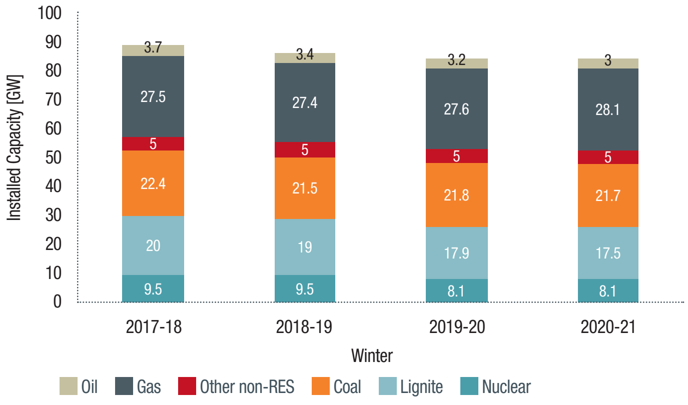
In 2010, the German government passed the 'Energiewende' legislation. One of the key points in this energy transition policy is the phase out of all German **nuclear** power production by 2022. Of the 17 nuclear reactors in operation at the end of 2010, nine have already been taken out of operation. It is expected that two more nuclear power plants will be shut down over the next three winters, one expected to shut down at the end of 2017 and the other at the end of 2019 [54].

Since 2010, almost half of installed nuclear capacity has been taken out of operation. This amounts to a nearly 10 GW reduction in installed nuclear power production.

In 2016, approximately 39% of the electricity generated in Germany was fuelled by **coal and lignite** [72], down from 43% in 2015 [73]. A significant reduction in the installed capacity of German coal and lignite production is expected. This is due in part to 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 envisaged by 2019-20 and 2020-21. Several new efficient CCGT plants are expected to come online in the coming years.

INSTALLED NON-RENEWABLE PRODUCTION IN GERMANY CONSIDERED FOR THE 'BASE CASE' IN THIS STUDY (FIG. 67)

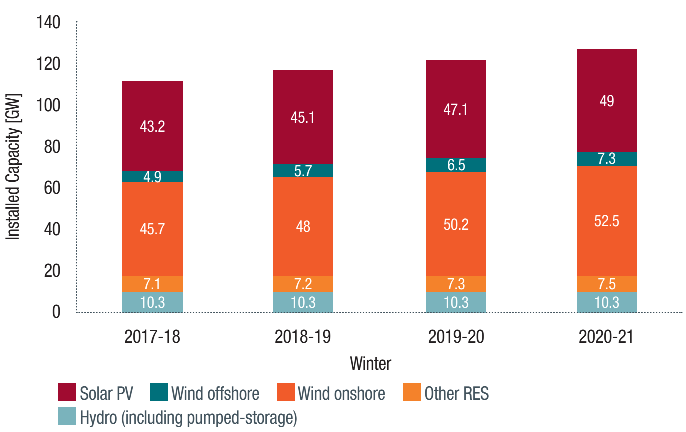


CHANGE IN RENEWABLE CAPACITY IN GERMANY

Figure 68 shows the hypotheses used for the installed capacity of German renewable electricity production. In 2016, almost 30% of German electricity production originated from renewable sources [72], compared to nearly 29% in 2015 [73]. This large share of renewables in electricity generation is due to the high volume of wind and solar capacity; installed capacity of more than 90 GW for winter 2017-18. Taking into account biomass, hydro and other renewables, the installed capacity of renewable electricity production exceeds 110 GW for winter 2018-19.

This study takes into account an average yearly growth of 5% (2.3 GW) for onshore wind production and 4% (1.9 GW) per year for photovoltaic production. An increase in offshore wind capacity is also forecast to reach around 6.4 GW by winter 2019-20 and 7.2 GW for by winter 2020-21. Other renewables are assumed to stay stable over the studied period. Germany has around 10 GW of hydro production capacity including pumped-storage facilities of around 6 GW and run-of-river facilities of about 4 GW.

INSTALLED RES AND PUMPED-STORAGE (FIG. 68)

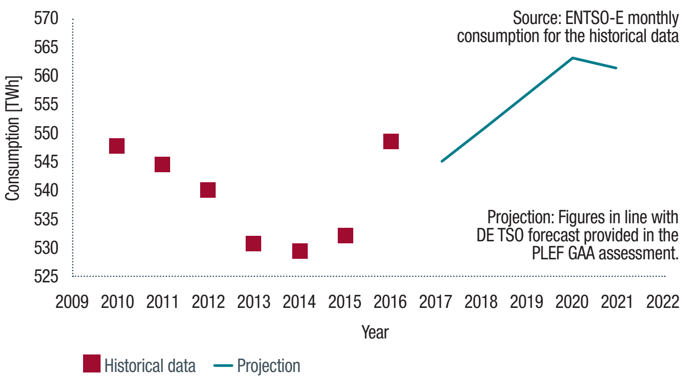


4.3.2. ELECTRICITY DEMAND IN GERMANY

During the period 2010-2014, an average yearly decrease of approximately 1% was observed in Germany's total electricity demand (not normalised). This trend appears to have changed around 2015. The assumption used in this study for German demand is given in Figure 69 and provides an upward forecast trend between 2017 and 2020. This trend is in line with the forecast provided by the German TSOs within the PLEF GAA regional study [60], and is mainly caused by an assumed increased consumption of Electric Vehicles (EVs) and Heat Pumps (HPs). These hypotheses were advanced as the most relevant for an adequacy assessment. Furthermore, it is assumed that Germany's load will decrease slightly from 2020-2021 to 2023-24 due to trends in increasing energy efficiency in line with political objectives, which will offset the abovementioned new uses due to EVs and HPs.

A 1 GW volume of 'switchable loads' is reported as being available in Germany by German TSOs in the PLEF study [60]. However, this should not be considered as market response potential in Germany, but rather as emergency 'switchable loads' to be used by German TSOs only in emergency situations in operational real-time. Therefore no market response potential is taken into account in the modelling for Germany here.

DEMAND EVOLUTION IN GERMANY AND FORECAST (FIG. 69)



4.3.3. SECURITY OF SUPPLY IN GERMANY

In Germany three different reserve mechanisms were implemented by the amended German Energy Law (EnWG) in 2016. Two kinds of strategic reserve deal with adequacy issues in Germany: the 'Security Reserve' and the 'Capacity Reserve'.

The capacity of the 'Security Reserve' is expected to be around 2 GW for winter 2018-19 and 2.7 GW for winter 2019-20. The capacity will consist mainly of lignitefired power plants. It is expected that the 'Security Reserves' will be phased out completely in October 2023.

The plan is to tender 'Capacity Reserve' in mid-2018 for a period of five years; it should be available as of winter 2018-19. It is thus planned that German TSOs will contract 2 GW of Capacity Reserve in 2018-19.

The third element refers to 'Grid Reserve' which may be activated by TSOs primarily for redispatch in case of network congestion in Germany. Some 6.8 GW of 'Grid Reserve' was contracted by German TSOs for the winter 2017-18. The German regulator (BNetzA) has confirmed 3.7 GW as the amount needed for 2018-19.

None of these three reserves are allowed to participate in the energy market. Therefore the abovementioned generation capacities are not considered in this study.

The information in this sub-chapter is provided by the German TSOs within the PLEF GAA study [60].

GREAT BRITAIN

As of winter 2017-18, security of supply in Great Britain is managed through the Capacity Market (CM), based on a recommendation regarding the capacity to secure provided by the British TSO National Grid.

In its 'Winter Outlook Report 2017-18', the British TSO National Grid indicates that no security of supply problems are expected for winter 2017-18.

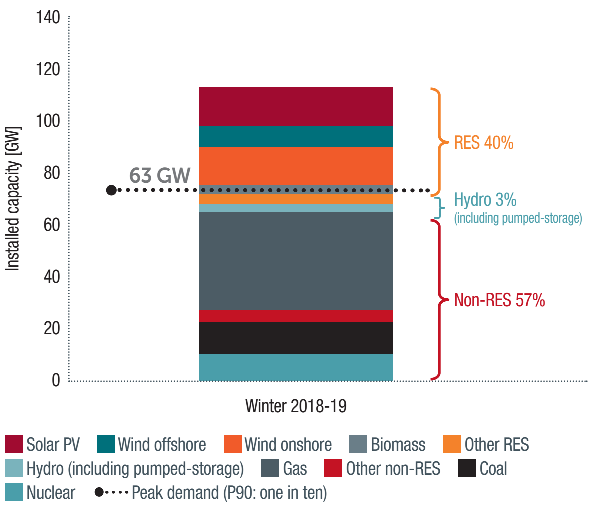
A reduction of the installed thermal capacity is foreseen, in part resulting from the introduction of a Carbon Price Floor (CPF) in 2013. More specifically approximately 75% of the installed capacity of coal-fired power production is expected to close over the course of the next four winters.

This section elaborates on the assumptions used in this study for Great Britain. In general, these assumptions are in line with the 2017 edition of the Future Energy Scenarios (FES) [24]. The FES is a report published by 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 different scenarios detailed in the FES report are limited when considering the short term.

In the 2013 Energy Act [51], 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 capacity market is meant to ensure security of supply in Great Britain, and is discussed in greater detail in section 4.4.3 on the general security of supply in Great Britain. The CfD mechanism provides incentives for low-carbon electricity generation capacity.

Section 4.4.1 elaborates on the assumptions used with regard to the electricity supply for Great Britain. Section 4.4.2 details the demand hypotheses used in the current analysis. Figure 70 summarises the supply and demand hypotheses for Great Britain for winter 2018-19.

INSTALLED CAPACITY AND P90 PEAK DEMAND CONSIDERED IN THE 'BASE CASE' SCENARIO FOR WINTER 2018-19 IN GREAT BRITAIN (FIG. 70)



4.4.1. ELECTRICITY SUPPLY IN GREAT BRITAIN

NON-RENEWABLE ELECTRICITY GENERATION

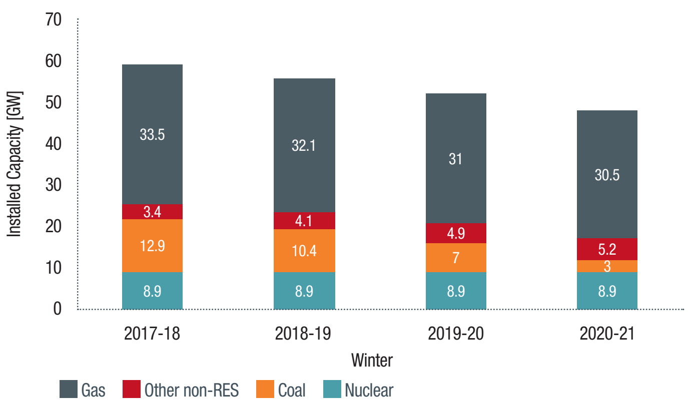
Historically, in Great Britain, electricity generation has mainly been dominated by gas, coal, and nuclear power production. However, in 2013, the British government introduced a Carbon Price Floor (CPF). Initially, this mechanism aimed to induce a carbon price of £30/tCO_2 by 2020[34], but it was modified in 2016 to limit its impact on British competitiveness [52].

Figure 71 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 the installed capacity of coal-fired production of about 4.4 GW in 2017 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 12.9 GW for winter 2017-18 to 3.0 GW for winter 2020-21. In total, this amounts to a decrease of approximately 75% of installed coal-fired capacity over four winters.

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 3 GW from the 2017-18 levels is expected. This decrease is partly offset by additional CHP projects and other small non-renewable generation. No closures of existing **nuclear** units are taken into account, and the most advanced new nuclear project in Great Britain – the EPR Hinkley Point C – will not be online in the years in question.

The installed capacity of coal-fired plants is expected to decrease by approximately 75% over four winters in Great Britain.

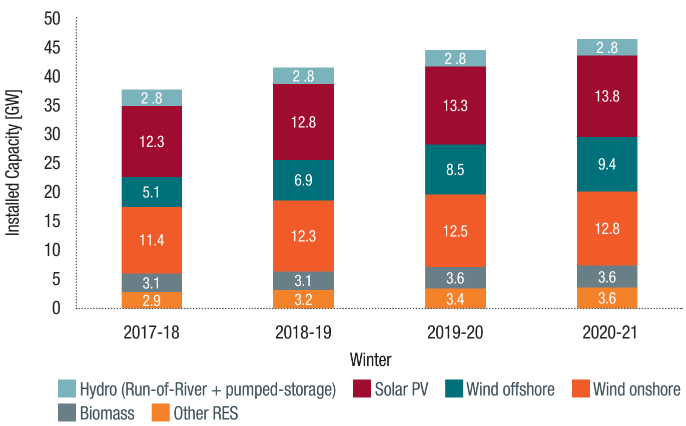
INSTALLED NON-RENEWABLE PRODUCTION IN GREAT BRITAIN CONSIDERED FOR THE 'BASE CASE' IN THIS STUDY (FIG. 71)



RENEWABLE ELECTRICITY GENERATION

Figure 72 shows the assumptions used in this study for renewable electricity production 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 almost double by winter 2020-21 compared to winter 2017-18. For photovoltaic and onshore wind production, a limited increase of approximately 12% in installed capacity is expected for the same period. No significant evolution is expected during the period in question 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. 72)



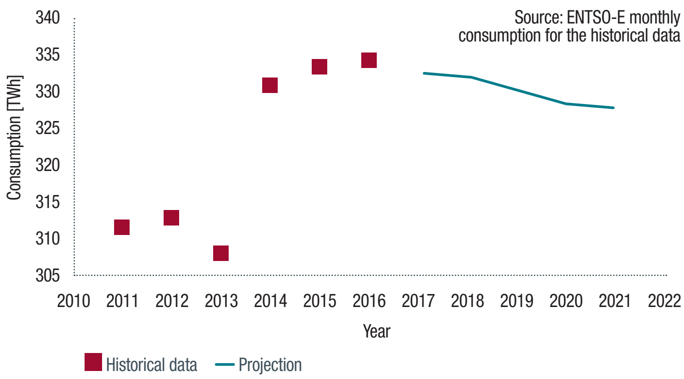
34. A carbon price of £30/tCO2 by 2020 in 2009 prices was initially envisaged.

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 set out in the 2017 FES report. This scenario envisages a reduction in normalised yearly electricity demand up to 2021, as in three of the four 2017 FES scenarios. The 2017 FES 'Two Degrees' scenario is the only scenario which foresees a slight increase in demand due to the very rapid electrification of transport. In the case of the 'Slow Progression' scenario, this demand reduction amounts to approximately 0.4% per year between 2017 and 2021.

Figure 73 shows the 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.

DEMAND EVOLUTION IN GREAT BRITAIN (FIG. 73)



4.4.3. SECURITY OF SUPPLY IN GREAT BRITAIN

As of winter 2017-18, Great-Britain's security of supply is managed through its Capacity Market (CM). British TSO National Grid performs an analysis to determine the capacity that must be contracted in order for Great Britain to be able to meet its adequacy criterion of an average LOLE of less than or equal to three hours. A recommendation of the capacity to contract is made using a Least Worst Regret (LWR) methodology that takes into account multiple scenarios (including the FES scenarios) and sensitivities. Subsequently, it is up to the government to decide on the details of the Capacity Market auction.

The first CM auction was held in December 2014 for delivery in winter 2018-19. For winter 2017-18, capacity was auctioned via an 'Early Auction' in February 2017 and a 'Transitional Auction' in March 2017. In its 'Winter Outlook Report 2017-18' [66], National Grid indicates that no security of supply problems are expected for winter 2017-18.

The latest report analysing security of supply in Great Britain in the medium term is the Electricity Capacity Report 2017 [53] submitted in May 2017 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 2018-19 and 2021-22. The British government followed the recommendation made by National Grid with minor adjustments [67], and the auctions for ensuring capacity for winters 2018-19 and 2021-22 will take place at the start of 2018.

WINTER OUTLOOK REPORT 2017-18

Source: National Grid – 12 October 2017

We expect there to be sufficient generation and interconnector imports to meet demand throughout winter 2017-18. This winter will be the first delivery year for the Capacity Market (CM). It aims to ensure security of electricity supply by providing a payment for reliable sources of capacity, alongside electricity revenues, to ensure the delivery of electricity when needed. This will encourage the investment required to replace older power stations and provide backup for more intermittent and inflexible low carbon generation sources. The Capacity Market has increased the amount of available supply in the market.

[...]

Since then, additional plant without CM contracts have indicated they will be operational this winter. As a result the margin forecast has increased to 6.2 GW, or 10.3 per cent, on an underlying demand basis, while on a transmission demand basis the margin is 11.5 per cent. In both cases the equivalent loss of load expectation (LOLE) is 0.01 hours per year.

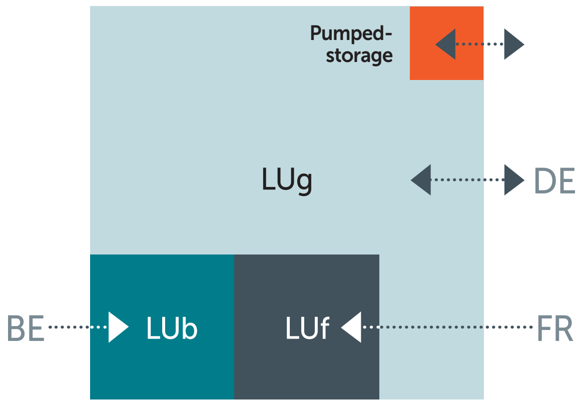
LUXEMBOURG

The modelling of Luxembourg is important for Belgium as part of the country is connected to the Belgian control zone (this is indicated as the 'LUb' zone in Figure 74). In 2016, the CCGT located in Luxembourg but belonging to the Belgian regulation zone was closed definitively [55]. Following this closure, the 'LUb' zone includes only consumption. The consumption of that zone is therefore counted as part of Belgian 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 country's hydro, wind, PV and the remaining load.

The 'IC BeDeLux' project, which physically connects the 'LUb' and 'LUg' zones, is not taken into account in this study. See section 5.1.4 for more information.

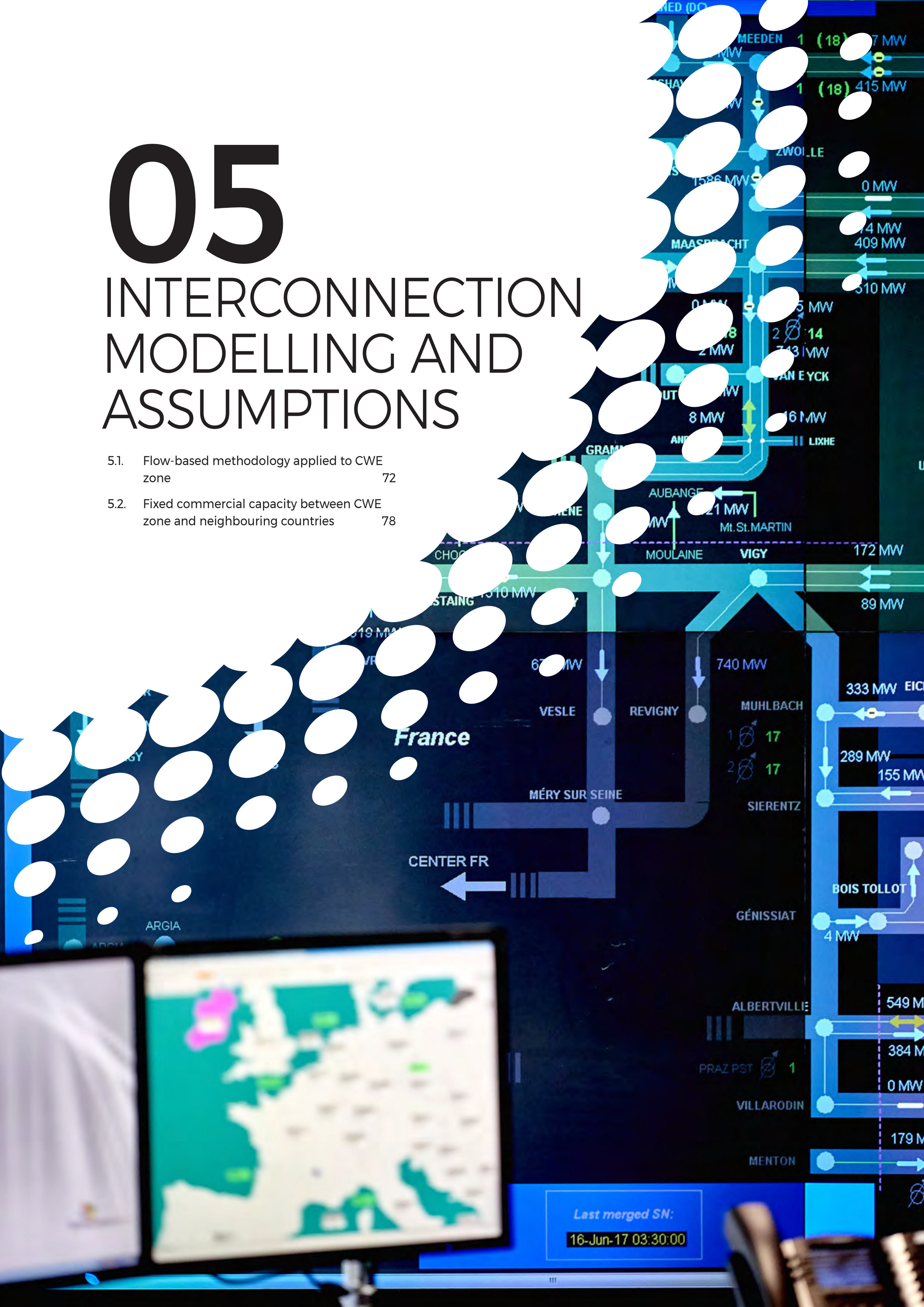
LUXEMBOURG MODELLING (FIG. 74)



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 covering 2020 and 2025 (see section 1.8.4 for more information), ENTSO-E transparency platform [27], ENTSO-E statistics [34], bilateral contacts, PLEF adequacy study, national reports and statistics.

05
INTERCONNECTION MODELLING AND ASSUMPTIONS



Belgium is at the heart of the interconnected European grid. It is surrounded by France, the Netherlands, Germany, and Luxembourg, which, depending on the situation of their respective grids and markets, can each import or export large amounts of electricity. Moreover, as of winter 2019-20, the Nemo Link® interconnector will enable Belgium to directly exchange electricity with Great Britain. As Belgium is structurally dependent on imports to ensure its adequacy, correctly modelling these interconnections is crucial.

Exchange capabilities between countries are modelled in this analysis in the same way as currently done on the day-ahead market (see Figure 75 and Figure 76):

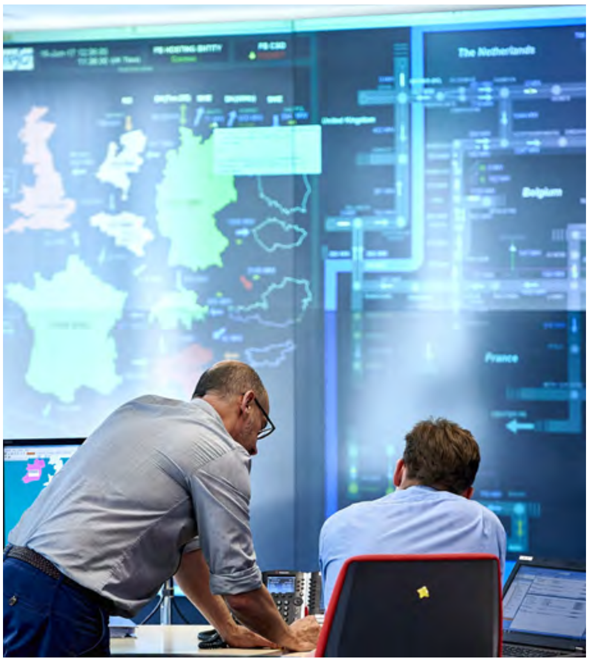
- Commercial exchanges **inside the CWE** region are taken into account using the same **flow-based** methodology as applied today. This is further described in section 5.1;
- Exchanges between **other countries and the CWE zone** are modelled with **fixed exchange capacities** (also called NTC – Net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

INTERCONNECTIONS INSIDE THE CWE ZONE ARE MODELLED WITH THE FLOW-BASED METHODOLOGY (FIG. 75)

MAXIMUM SIMULTANEOUS IMPORT CAPACITY FOR BELGIUM

Belgium's maximum simultaneous import capacity 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) that results from the need of ensuring sufficient 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. It is an input into the flow-based domain calculation.

For the winter 2018-19 analysis, the maximum simultaneous import capacity is assumed to be equal to 4500 MW. This is in line with the expected maximum simultaneous import capacity to be used in real-time operations. As of winter 2019-20, when also the Nemo Link® High-Voltage Direct Current (HVDC) interconnector will be operational, Belgium's total maximum simultaneous import capacity is assumed to reach 5500 MW.



FLOW-BASED METHODOLOGY APPLIED TO CWE ZONE

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 the day-ahead operation. Building on the experience of the previous assessments for winters 2016-17 and 2017-18, and taking into account feedback received from market parties, more flow-based domains are used for the winter 2018-19 assessment (see Figure 76). The correlation of the flow-based domains with climatic conditions was also thoroughly analysed. Moreover, the planned grid reinforcements to be commissioned in the CWE area before winter 2018-19 are taken into account when calculating the relevant flow-based domains.

EVOLUTION OF THE IMPLEMENTATION OF THE FLOW-BASED METHODOLOGY THOUGHOUT THE ASSESSMENTS (FIG. 76)

2015-16	NTC only modeling
2016-17	1 flow-based domain for all winter
2017-18	Three flow-based domains with DE wind correlation
2018-19	**4 x 24 flow-based domains** with a detailed climate correlation

POSSIBLE GERMAN - AUSTRIAN BIDDING ZONE SPLIT

At the moment, discussions are ongoing concerning the possible split of the combined German – Austrian bidding zone into two different bidding zones, following a decision by the German regulator Bundesnetzagentur in October 2016 [70]. Currently, there still exists a lot of uncertainty on the timing, as well as on the details of such a possible split. Therefore, for this analysis the German – Austrian bidding zone is modelled as a single bidding zone for the whole horizon of the study.

The flow-based method used for this analysis was developed and implemented by French TSO RTE (see reference documents [74] and [75]), and is also used in RTE's adequacy study (Bilan Prévisionnel 2017 [33]) as well as in the PLEF GAA forthcoming report to be published in January 2018. The newly developed method can be summarised as follows:

i) The method **is consistent** with the method used last year;

ii) A larger set of domains, **4 x 24 hourly historical domains,** is used;

iii) A **systematic approach** was used to correlate the above 4 x 24 flow-based domains with **expected climatic situations** for the next winters.

These improvements make it possible to better capture uncertainties about Belgium's import and export capabilities.

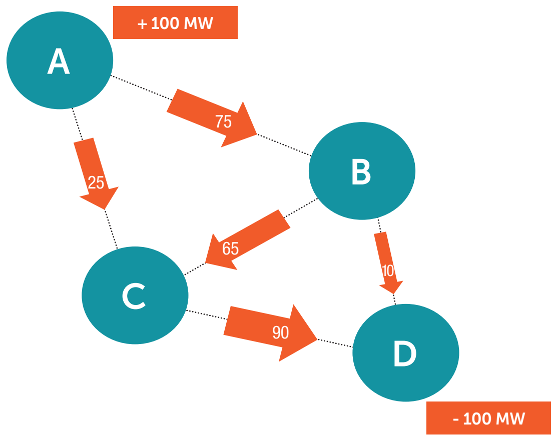
5.1.1. WHY FLOW-BASED METHODOLOGY IS INCLUDED IN THIS STUDY?

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

The flow-based method makes it possible to properly take into account interactions between market outcomes and the transmission grid. For instance, at moments when both France and Belgium are in structural shortage, Belgium's achievable imports 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 reduced imports on adequacy as a result of market conditions in neighbouring countries.

Figure 77 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).

RESULTING FLOWS FROM AN ENERGY EXCHANGE BETWEEN 2 ZONES (FIG. 77)



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

An informative explanation (in French) of flow-based market coupling is available. It is based on a film produced by the French energy regulator (CRE) [44].
More information about the flow-based rules and methodologies is available from Elia [45], JAO resource center [46] and EPEX Spot Belgium [47].

The flow-based method implemented in day-ahead market coupling uses PTDF factors that make it possible to model real flows through 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') taking into account the N-1 criteria is calculated (see box on N-1 criteria). This leads to constraints, which form a domain of safe possible energy exchanges between the CWE countries (this is called the flow-based domain).

This domain is constructed on a foundation of 'critical branches' (lines or grid elements – hereafter referred as CBs), taking into account the impact of an outage on these CBs, a reliability margin on each CB and, where appropriate, 'remedial actions' that can be taken after an outage to partly relieve the loading 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 outside the CWE area, 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 calculation of the flow-based domain is started 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 FOR THE GRID

Interconnection capacity takes into account the margins that transmission system operators must maintain in order to follow the European rules ensuring the security of supply. A line or grid element can be lost at any time. The remaining lines must 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 transmitting 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 N-1 cases.

Note, however, that European rules stipulate that this criterion must be fulfilled at each moment, including in the event of maintenance or repair work. In such cases, it is possible that interconnection capacity will have to be reduced. Wherever possible, maintenance and repair works are 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.

THE ADEQUACY PATCH

The CWE flow-based algorithm includes an 'adequacy patch' defining rules for sharing energy exchanges in scarcity situations.

If a country has a structural shortage (day-ahead price reaches 3000 €/MWh in that country) the maximal 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 shortage, imports will be allocated to those countries in proportion to their respective needs, on the basis of a quadratic function defined in the Euphemia market coupling algorithm.

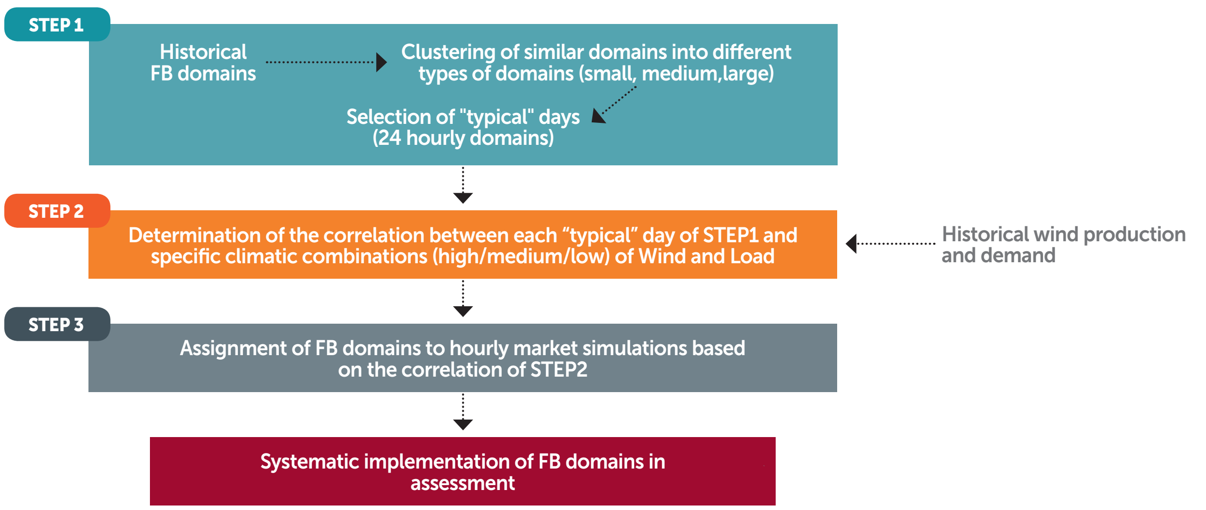
For the purposes of the adequacy study, the adequacy patch is taken into account in the results from ANTARES in post-processing.

5.1.3. IMPROVED METHOD FOR DETERMINING THE REPRESENTATIVE FLOW-BASED DOMAINS AND THEIR CORRELATION WITH CLIMATIC VARIABLES

The representative flow-based domains have been chosen after analysis of historical data for winter 2015-16 and winter 2016-17. Three main steps (see Figure 78) have been followed to define the relevant flow-based domains for the analysis of winter 2018-19:

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

CONSTRUCTION /SELECTION OF FLOW-BASED DOMAINS (FIG. 78)



STEP 1 SELECTION OF 'TYPICAL' DAYS

A statistical analysis of the geometrical shapes of available flow-based domains is performed on historical records of domains from the FB CWE operational tool. Historical days are therefore clustered in families defined by the size of their 24 hourly domains, *i.e.* typically 'large', 'medium' and 'small' families of domains are clustered. Each typical day consists of 24 hourly domains (one for each hour).

- Small domains correspond to situations with a highly congested network and therefore with small values for the maximum power exchanges possible between the different market areas considered by the given domain (related to the small volume inside the domain).
- Large domains correspond to situations with a less congested network and therefore relatively higher values of maximum possible power exchanges between the market nodes considered by the given domain (larger volume).
- A typical day is the historical day within a given family or cluster of domains, which provides the best representation of all the other days in the cluster.
- Since flow-based domains are hourly, this typical day is selected by comparing its domain at every hour to the other day's equivalent domain (at the same hour).

STEP 2 CORRELATION BETWEEN EACH 'TYPICAL' DAY AND SPECIFIC CLIMATIC COMBINATIONS

Four typical days for winter are found as a result of the clustering (three weekdays and one weekend day). A probability matrix is then calculated as a function of daily energy ranges (high/medium/low) of wind production and load. This calculation provides the correlation of each typical day (24 hourly domains) to given climatic combinations (e.g. low wind, high load).

STEP 3 ASSIGNMENT OF FLOW-BASED DOMAINS TO HOURLY MARKET SIMULATIONS

The typical days for winter of Step 1 are used as *proxies* for the relevant domains expected during next winter 2018-19 and are assigned to hourly simulations by the correlation found in Step 2. Each hourly simulation of the interconnected power system presents different expected climatic, generation and demand situations during next winter.

This kind of systematic approach makes it possible to link specific combinations of climate conditions expected next winter, e.g. high/low wind infeed in Germany, high/low temperature and demand in France and Belgium with representative domains for these conditions. The systematic approach constitutes a significant improvement compared to last years' assessment, where the domains were assigned to specific hours based on the German wind production only.

5.1.4. WHAT CHANGES HAVE BEEN MADE TO THE 'REPRESENTATIVE OPERATIONAL DOMAINS'?

The representative flow-based domains determined in section 5.1.3 were updated to take into account the grid reinforcements to be commissioned before winter 2018-19. This was done by the TSOs in question in the context of the PLEF GAA study. Recent and upcoming investments in Belgium on the 380kV grid already operational or scheduled to be operational before the start of winter 2018-19 and which were considered relevant for the calculation of flow-based domains to be used in the assessment are given below.

WINTER 2018-2019

- BRABO I: 380.26 Doel-Zandvliet + 2nd PST at Zandvliet;
- Splitting of line 380.73 (Doel – Horta) into two segments: 380.53 (Doel – Mercator) and 380.73 (Mercator – Horta);
- 2nd 380kV circuit Lixhe-Herderen + new GIS substation 380kV at Lixhe;
- The margin given by installations for monitoring the lines ('Dynamic Line Rating: Ampacimons') has been integrated where available according to current operational rules;
- Stevin project.

Changes to the historical domains were applied in order to take account of these upcoming investments. Furthermore, all Belgian nuclear units were set to maximum output in the historical day files that were used to construct the flow-based domains. Similar considerations were also performed for the other countries within CWE (Austria, Germany, France, the Netherlands and Luxemburg). A full overview of the applied changes in neighbouring countries will be published in the forthcoming PLEF report.

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

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

On one hand, the Nemo Link® HVDC [43] interconnection with Great Britain, was taken into account as of winter 2019-20 in the 'base case'. The link is modelled as an NTC link without impact on the flow-based domains, and the connection has an exchange capability of 1000 MW between Belgium and Great Britain.

The planned HVDC interconnection with Germany (ALEGrO project [42]) has a target commissioning date of 2020. Given the uncertainty about its exact commissioning date and regarding the integration of the ALEGrO project in the flow-based operations, the impact of this interconnection has not yet been taken into account for the simulations conducted in this study.

IC BeDeLux project

The IC BeDeLux one-year technical trial period began on 11 October 2017. The commercialisation of this connection between the Belgian and the Austrian-Luxembourg-German market hub will be assessed after the first phase of the technical trial. Consequently, the interconnection is not taken into account for the current analysis.

IC BEDELUX - TECHNICAL GO-LIVE OF PHASE SHIFTER TRANSFORMER IS SCHEDULED 11 OCTOBER 2017

Source: Elia – 29 September 2017

The technical go-live for the phase shifter transformer (PST) situated in Schifflange connecting the Elia and Creos grids is scheduled for 11 October 2017. The technical trial period consists of two phases and will last one year starting from the moment of the technical go-live.

After the first phase of the technical trial period the project will conduct an assessment to evaluate whether new insights have been gathered that would make it possible to start the commercialisation of the interconnector earlier. From the moment of the technical go-live the Luxembourg security of supply situation will be further improved, thus ensuring the project's main trigger.

5.1.5. ILLUSTRATION OF THE DOMAINS USED FOR THIS STUDY

The relevant typical days found by the clustering procedure explained above for the winter period are:

- Flow-based typical day 1: 10-12-2015 (Weekday - SMALL)

- Flow-based typical day 2: 08-02-2016 (Weekday - MEDIUM)

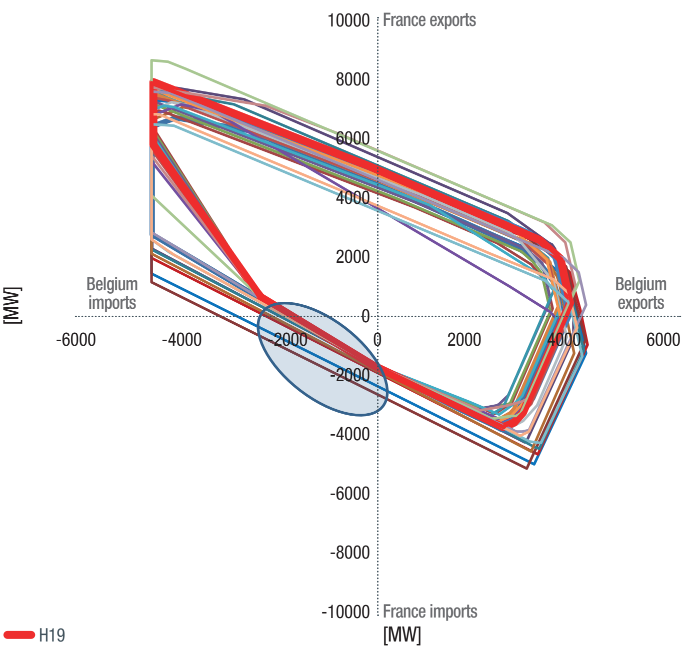
- Flow-based typical day 3: 03-02-2016 (Weekday - LARGE)

- Flow-based typical day 4: 06-02-2016 (Weekend - WE)

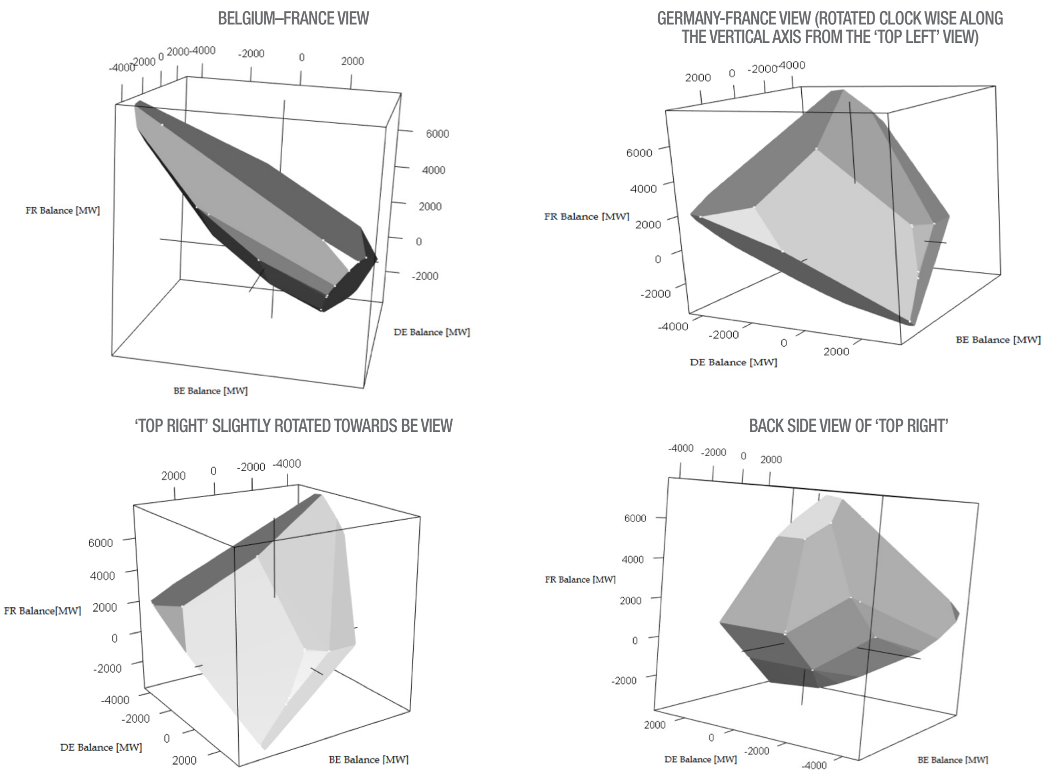
Each typical day consists of 24 hourly domains (one for each hour). The projections of the 24 domains for the flow-based typical day 1 (SMALL) onto the Belgium-France balance plane are shown in Figure 79. It can be seen that hour 19 (from 18:00–19:00) provides a highly constraining boundary in the lower left quadrant. This boundary is highly relevant for the Belgium adequacy, as it constrains the combined import capacity available to France and Belgium from CWE.

The exchange possibilities between all countries within the CWE flow-based region are determined by a multidimensional domain or flow-based surface made of all the intersecting planes in three dimensions corresponding to the limiting critical branches/ elements. For illustration purposes, a view of such a multidimensional domain is shown in Figure 80, for the typical day 1 (SMALL), hour 19.

THE 24 HOURLY DOMAINS FOR THE FLOW BASED TYPICAL DAY 1 (SMALL) (FIG. 79)



FOUR DIFFERENT FACETS OF THE 3D FLOW-BASED SURFACE (FIG. 80)

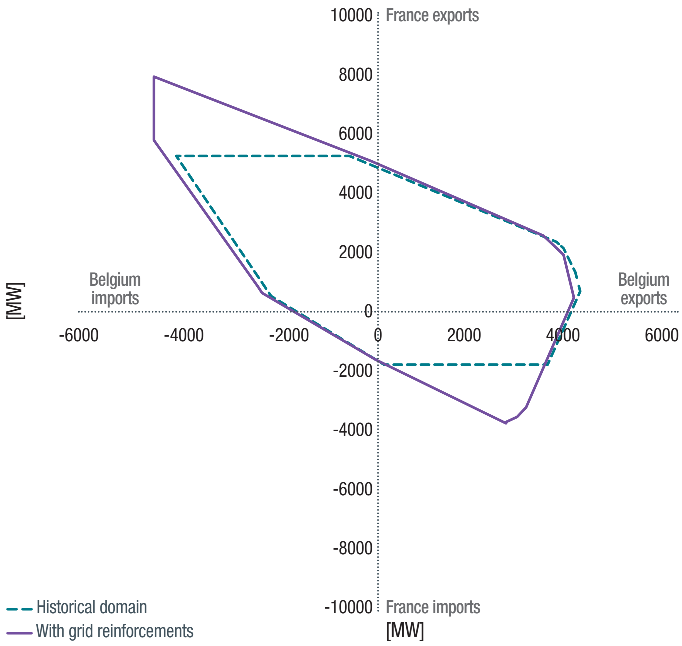


The domains used in the assessment are based on historical domains from the CWE flow-based environment, but include the effect of planned grid reinforcements up to winter 201819 in the CWE area. Taking grid reinforcements into account generally increases exchange capacities. The domains illustrated in Figure 81 for the typical day 1 (SMALL), hour 19, include the effect of the planned grid reinforcements.

In Figure 82 and Figure 83, the weekday domains at hour 19 that are used in the current assessment for winter 2018-19 are compared to the weekday domains used in the previous assessment for winter 2017-18. It can be observed that the domains at hour 19 for typical day 1 (SMALL) and typical day 2 (MEDIUM) that are used in this study are comparable to the 'Windy' domain used for the assessment of winter 2017-18. A detailed analysis of the impact of the domains on the adequacy results is presented in section 6.1.1.2.

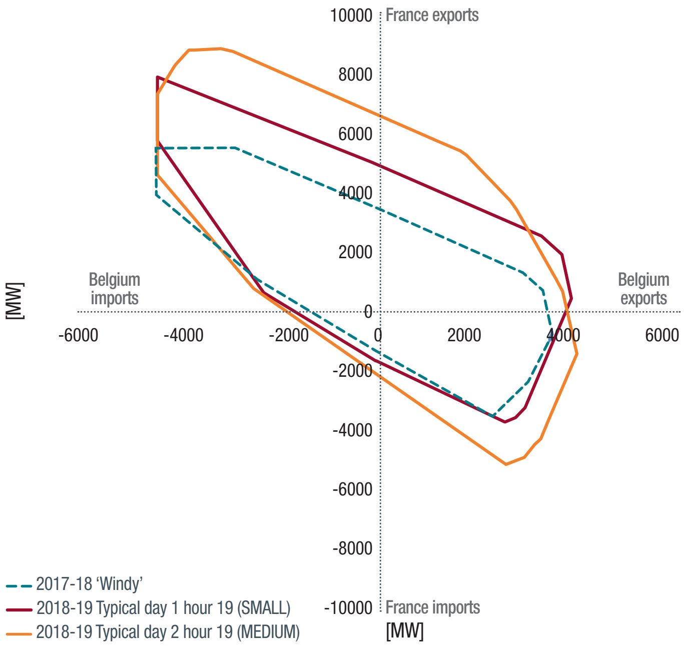
The flow-based domains in the figures shown above only reflect exchange capacities between the countries inside the CWE region, so the import possibilities of CWE countries from outside CWE are not shown. In the model used for determining the volume of strategic reserve (ANTARES) as well as in day-ahead market coupling, France can for example import from 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).

GRID REINFORCEMENTS IMPACT FOR THE FLOW-BASED TYPICAL DAY 1 (SMALL), HOUR 19 DOMAIN (FIG. 81)

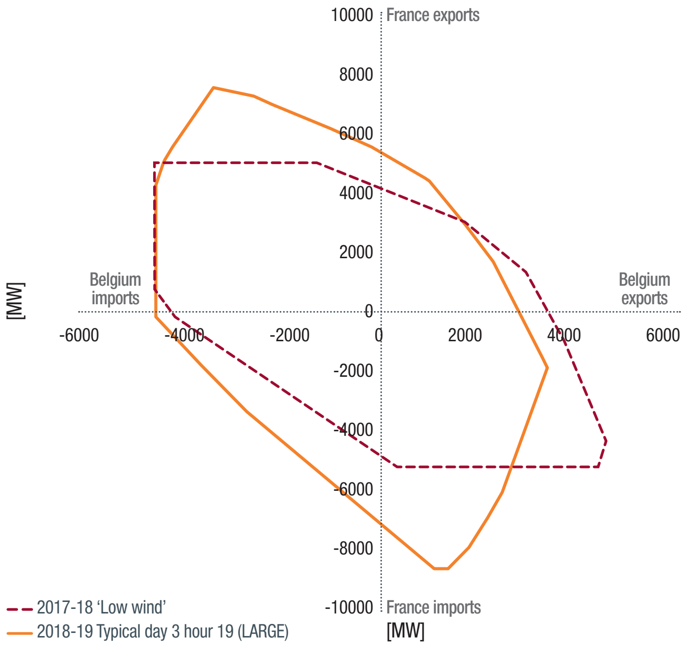


Grid reinforcements up to winter 2018-19 are taken into account in the calculation of the domains, generally allowing more exchanges than observed on the historical flow-based domains.

COMPARISON OF THE "WINDY" DOMAIN USED FOR THE ANALYSIS OF WINTER 2017-18 WITH THE HOUR 19 DOMAINS FOR THE TYPICAL DAYS 1 (SMALL) AND 2 (MEDIUM) USED IN THE ANALYSIS FOR WINTER 2018-19 (FIG. 82)



COMPARISON OF THE "LOW WIND" DOMAIN USED FOR THE ANALYSIS OF WINTER 2017-18 WITH THE HOUR 19 DOMAIN FOR THE TYPICAL DAY 3 (LARGE) USED IN THE ANALYSIS FOR WINTER 2018-19 (FIG. 83)



FIXED COMMERCIAL CAPACITY BETWEEN CWE ZONE AND NEIGHBOURING COUNTRIES

Countries outside the CWE zone and interconnections between the CWE zone and the rest of Europe are modelled with fixed maximum commercial exchange capacities. This is the same as defined today in the day-ahead market. The fixed commercial exchange capacities are also referred to as Net Transfer Capacities (NTCs). In section 5.2.1, the details of the modelling of the fixed commercial capacities are given. Next, in section 5.2.2, the methodological improvement concerning the modelling of the availability of High-Voltage Direct Current (HVDC) interconnections is detailed.

5.2.1. FIXED COMMERCIAL EXCHANGE CAPACITY ON THE BORDERS OF THE COUNTRIES OUTSIDE CWE REGION

The NTC capacities used in this study are obtained through studies conducted within ENTSO-E and from bilateral and multilateral contacts between Elia and other TSOs. The capacities take into account planned new interconnections for future winters. In reality, NTCs can vary from day to day depending on the conditions of the network, availability of lines and other network elements. In this study, a single reference value is used for a given interconnection in a certain direction during the entire period simulated. The historical exchange capacities can be found on the websites of the relevant system operators and on ENTSO-E's transparency website [27].

MAXIMUM WINTER IMPORT CAPACITY OF THE CWE ZONE FROM NEIGHBOURING COUNTRIES

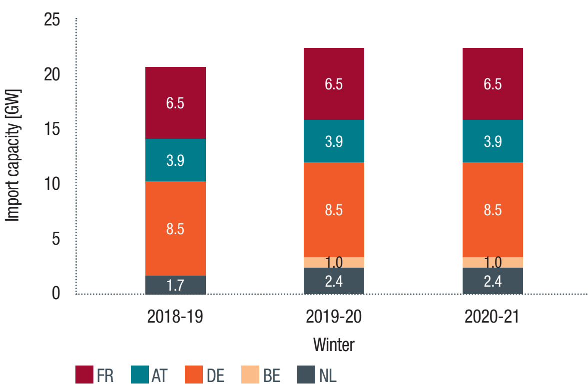
The impact of countries outside the CWE zone on the risk of a structural shortage in Belgium consists of the capacity of these countries to provide energy to the CWE zone in case of a power shortage at CWE level.

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

- France: Sum of net import capacity for France (from outside CWE) which is considered to be 6.5 GW for winter 2018-19. This value is the sum of the import capacities from Spain, Italy, Switzerland and Great Britain, and does not change over the course of the studied winters.
- The Netherlands: Sum of net import capacity of the Netherlands (from outside CWE), which is considered to be 1.7 GW for winter 2018-19. This value is the sum that can be imported from Norway and Great Britain. As of winter 2019-20, the 700 MW HVDC cable (COBRA cable [63]) between The Netherlands and Denmark is taken into account.
- Germany and Austria: Sum of net import capacity for Germany (from outside CWE), which is considered to be 8.5 GW (Germany) + 3.9 GW (Austria) for winter 2018-19. This value, which does not change over the course of the studied winters, 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 for Belgium (from outside CWE) is considered to be 0 GW for winter 2018-19 is. As of winter 2019-20, the future HVDC interconnection with Great Britain (Nemo Link®) is taken into account as an additional 1 GW.

The sum of import capacity shown in Figure 84 is the maximum possible import capacity to the CWE region (Belgium, France, the Netherlands, Germany, Austria, Luxemburg) 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 scope includes those countries, the availability of generation is explicitly taken into account.

ASSUMPTIONS REGARDING THE MAXIMUM IMPORT CAPACITY FROM OUTSIDE THE CWE ZONE (FIG. 84)



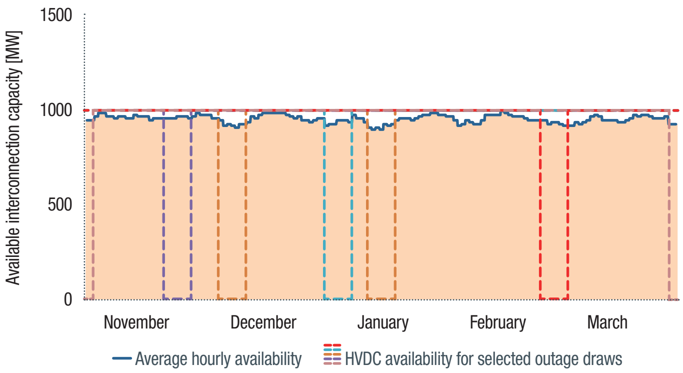
EXCHANGES WITH NON-MODELLED COUNTRIES

No exchanges between the countries that are modelled and those that are not modelled are considered. This is a conservative assumption because these exchanges do exist and could contribute to power supply of the CWE region. The countries modelled in addition to the CWE countries[35] are: Spain (ES), Portugal (PT), Great-Britain (GB), Ireland (IE), Northern Ireland (NI), Switzerland (CH), Slovenia (SI), Czech Republic (CZ), Slovakia (SK), Hungary (HU), Norway (NO), Denmark (DK), Sweden (SE) and Poland (PL). Since the geographical perimeter considered around Belgium is significant, the effect of the above mentioned assumption has little impact on the adequacy situation in Belgium.

5.2.2. HVDC FORCED OUTAGES

A detailed modelling of the availability of HVDC system elements was included in the analysis. The incorporation of outages of (selected) HVDC lines in the simulations is a new methodological improvement compared to previous assessments. The availability of HVDC interconnectors is modelled using a Forced Outage Rate (FOR), which in this case defines the annual rate an HVDC interconnector is unavailable. Forced outages are simulated by random occurrences of outages within the probabilistic 'Monte Carlo' scheme (see section 8.1), whilst respecting the annual rate defined. This is illustrated in Figure 85 for the 1000 MW Nemo Link® HVDC interconnector between Belgium and Great Britain. The figure shows the average availability for the interconnector throughout the winter, as well as some examples of availabilities for a given 'Monte Carlo' year. An unavailability rate for each HVDC interconnector of 6% has been used, in line with the value used for the ENTSOE MAF report [16].

ILLUSTRATION OF THE HVDC AVAILABILITY MODELLING FOR THE 1000 MW NEMO LINK INTERCONNECTOR (FIG. 85)



35. Germany (DE), France (FR), Belgium (BE), The Netherlands (NL), Luxembourg (LU) and Austria (AT).

06
RESULTS

This chapter contains the results for the three winters analysed: 2018-19, 2019-20 and 2020-21. Section 6.1 provides a detailed analysis of the results for the 'base case' scenario for winter 2018-19, as well as an outlook for the other two winters analysed. In addition to the 'base case' scenario, the sensitivity of nuclear availability in Belgium and France was analysed, in combination with the possible operation of the Drogenbos power plant in CCGT mode. This sensitivity, together with its results is discussed in section 6.2.

The results are given using the following adequacy indicators:

- The criteria defined by law (**LOLE average and LOLE95**) as discussed in section 1.3, given in hours and rounded 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 to zero decimal places. Both the average of the number of simulated 'Monte Carlo' years is given for the studied winter, as well as the P95;
- 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;
- When a need for a volume of strategic reserve is identified, the **number of activations** and the **length of an activation** of this volume are given with average, P95 and maximum values. When a margin is identified, these numbers are given for a hypothetical volume of strategic reserve.

'BASE CASE' SCENARIO

The 'base case' was constructed on the basis of the situation known in mid-October 2017. Below, a brief summary is given of this 'base case' scenario, with the details given in chapters 3, 4 and 5.

MAIN HYPOTHESES FOR BELGIUM:

- Thermal generation facilities as known at mid-October 2017, based on the latest closure announcements by producers (announced at the latest by 31 July 2017 for winter 2018-19). No major changes are taken into account between the three winters analysed (90 MW of turbojets are assumed to be decommissioned for winter 2019-20, and 170 MW of gas-fuelled production capacity is assumed decommission between winter 2018-19 and winter 2020-21);
- All nuclear units are considered available for all winters;
- Market response is taken into account in line with the results of the market response study (702 MW for winter 2018-19);
- Wind onshore and PV forecasts are a best estimate based on a consultation with the regions, the offshore capacity is forecasted based on a best estimate by Elia and FPS Economy;
- Profiled non-renewable installed capacity is kept constant for the three studied winters;
- Total demand growth is approximately 0.5%/year;
- Forced outage rates are based on the observed average over the last ten years, excluding the exceptional nuclear unavailability that was experienced in recent years in Belgium.

MAIN HYPOTHESES FOR OTHER COUNTRIES:

- **French** assumptions are in line with those used for the latest adequacy report published by RTE [33];
- **Dutch** hypotheses are in line with the latest TenneT adequacy report [48];
- **German** hypotheses are in line with the latest communications from German regulator BNetzA [76];
- **Great Britain's** assumptions are based on the 2017 FES 'Slow Progression' scenario [24].

INTERCONNECTIONS:

- A new interconnection between Belgium and Great Britain (Nemo Link®) capable of exchanging 1000 MW is assumed available from winter 2019-20 onward;
- Flow-based modelling with four typical days for winter 2018-19 is used in this assessment for the CWE region;
- A maximum simultaneous import capacity of 4500 MW is assumed for Belgium in winter 2018-19, increasing to 5500 MW for winters 2019-20 and 2020-21;
- NTC modelling for the rest of Europe is used.

6.1.1. RESULTS FOR WINTER 2018-19

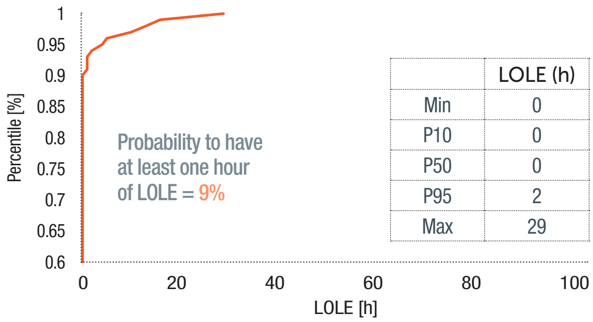
6.1.1.1. CALCULATION OF LOLE, ENS AND NUMBER OF ACTIVATIONS

As explained in chapter 2, a margin or deficit (i.e. a need for strategic reserve volume) is calculated for both legally required criteria (LOLE average and LOLE95). The resulting values are shown in Figure 86. The LOLE average for winter 2018-19 is 45 minutes and the percentile 95 is 2 hours. These results are lower than the criteria defined by law, and the margin corresponding to the 2018-19 'base case' scenario is 900 MW.

As can also be observed in Figure 86, the number of activations of a possible volume of strategic reserve would be very low: 0.2 times per year on average, twice per year in P95 and 8 times per year in the most extreme 'Monte Carlo' year simulated. The figure also indicates the maximum length that a possible volume of strategic reserve 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 15 hours without interruption. The average of the maximal activation length is around 2.4 hours. Furthermore, Figure 86 shows that the amount of Energy Not Served (ENS) is limited to 0.3 GWh over the winter on average and to 0.7 GWh in P95.

Figure 87 shows the cumulative distribution of the total 'Monte Carlo' years simulated 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 shortage are shown. This probability amounts to 9% for winter 2018-19. In the most extreme year simulated, 29 hours of structural shortage 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 2018-19, those are all equal to 0 hours, except for the P95 which equals 2 hours.

WINTER 2018-19 – 'BASE CASE' CUMULATIVE DISTRIBUTION OF LOLE WITHOUT STRATEGIC RESERVE (FIG. 87)



	LOLE (h)
Min	0
P10	0
P50	0
P95	2
Max	29

WINTER 2018-19 – 'BASE CASE' (FIG. 86)

	AVERAGE	P95
LOLE [h]	0h45	2h00
ENS [GWh]	0.3	0.7
Need [+] or Margin [-] [MW]	-900	-900

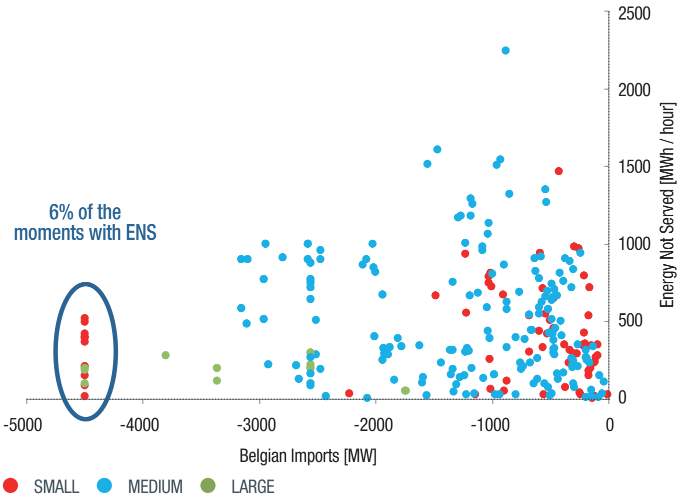
Margin of 900 MW

	AVERAGE	P95	MAX
Amount of activations	0.2	2	8
Activation lenght [h]	2.4	2	15

6.1.1.2. IMPORTS IN PERIODS OF STRUCTURAL SHORTAGE

The hours in which structural shortage is identified for winter 2018-19 in the 'base case' simulation, can be classified on the basis of Belgium's imports during these hours (see Figure 88). In this figure, each point represents one hour in which ENS is identified in Belgium. The graph shows imported energy for Belgium (resulting from flow-based market coupling), Belgian energy not served in MWh/hour, and the colours indicate the respective flow-based domain type of each hour in which ENS was identified. It is important to specify that this graph is based on the 'base case' simulation which has an average LOLE of 45 minutes.

HOURLY ENERGY NOT SERVED, DOMAIN TYPE, AND BELGIAN BALANCE FOR THE WINTER 2018-19 'BASE CASE' SCENARIO (FIG. 88)



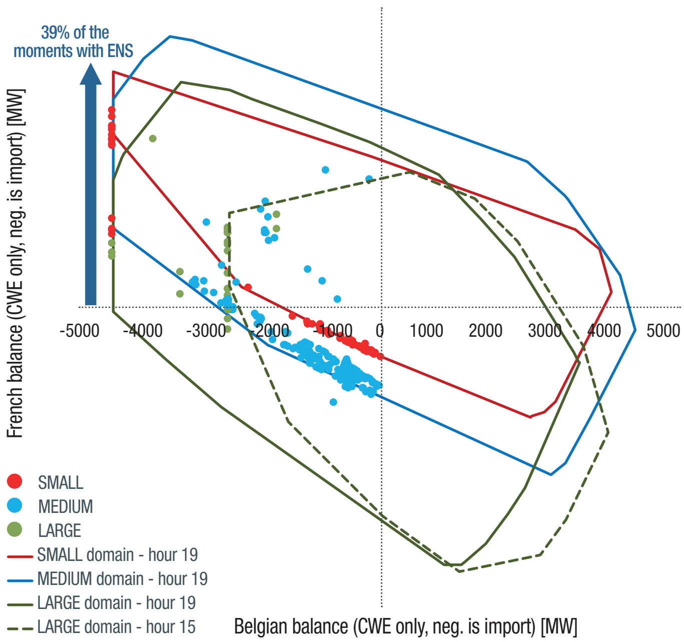
For the same hours with ENS shown in Figure 88, the Belgian and French balance (only exchanges with CWE countries) are given in Figure 89. Also, the colours in this figure indicate the typical day corresponding to each hour. For illustration purposes, the projection of the three weekday flow-based domains at hour 19 into the Belgian-French balance plane is given. Also, in striped lines, the large domain at hour 15 is given in order to illustrate the limits in exchanges for certain specific hours with ENS. It is important to stress that the ENS also occurs at other hours than hour 19, which is why the balances are not always tangent to or on the inside of the domains shown.

Based on the information in Figure 88 and Figure 89, three different situations can be distinguished with respect to the Belgian net position when ENS occurs:

1. Belgium can import 4500 MW;
2. Belgium can import less than 4500 MW, and France can export to CWE;
3. Belgium can import less than 4500 MW and France needs imports from CWE.

All three situations are discussed in detail below.

BELGIAN AND FRENCH BALANCE (CWE ONLY) FOR HOURS WITH ENS IN THE WINTER 2018-19 'BASE CASE' SCENARIO (FIG. 89)



1 BELGIUM CAN IMPORT 4500 MW

Approximately 6% of the time when ENS is occurring in Belgium, 4500 MW can be imported from CWE. As can be derived from Figure 88, the amount of energy not served in those hours is relatively limited with maxima around 500 MWh/hour.

2 BELGIUM CAN IMPORT LESS THAN 4500 MW, AND FRANCE CAN EXPORT TO CWE

The second category of hours when ENS is occurring in Belgium is defined by less than 4500 MW of imports to Belgium, with France still being able to export to CWE. This amounts to approximately 33% of ENS hours in Belgium. The majority of these situations provide Belgium with more than 1500 MW of imports, resulting in maximal unserved energy of around 1000 MWh per hour. However, a limited amount of observed situations result in lower imports, giving rise to ENS values exceeding 1000 MWh/hour.

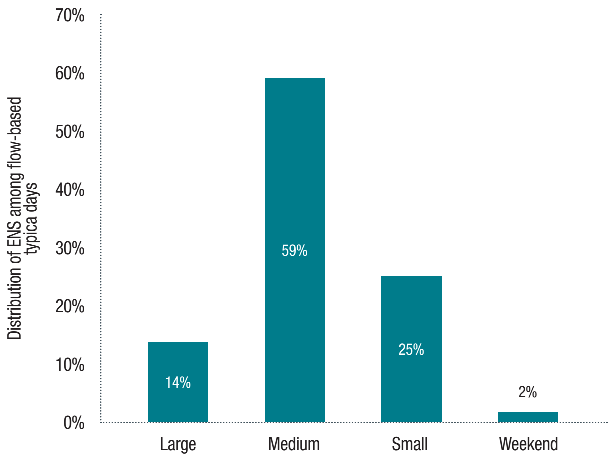
3 BELGIUM CAN IMPORT LESS THAN 4500 MW AND FRANCE NEEDS IMPORTS FROM CWE

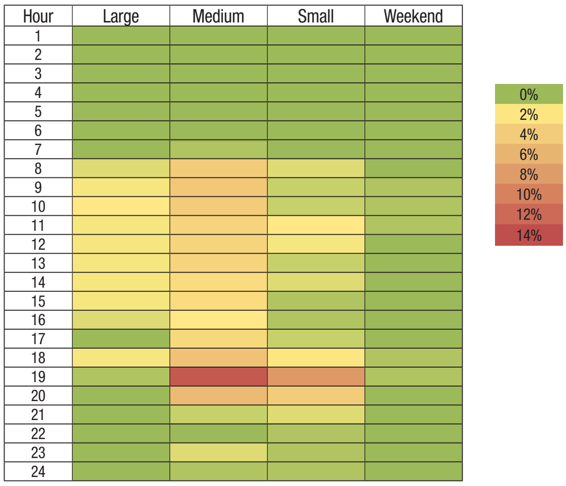
The remaining 61% of ENS hours in Belgium are characterised by simultaneous import needs by both Belgium and France. In these situations, the amount of energy not served per hour can exceed 1500 MWh/hour.

Figure 90 shows the distribution of ENS among the different flow-based domains for the winter 2018-19 'base case', both per hour and aggregated per 'typical day'. The hours with highest contribution to ENS are 'hour 19' (18:00 - 19:00 CET), 'hour 18' (17:00 - 18:00 CET) and 'hour 20' (19:00 - 20:00 CET) for the medium and small domains. These hours typically correspond to the highest European residual load (load – renewable generation) from observed historical data (see ENTSO-E Seasonal Outlooks [78]) and are the hours when the peak load typically occurs for France and Belgium in winter.

Furthermore from the hourly distribution of ENS amongst the FB domains analysis in Figure 90, it is clearly visible that ENS occurs also at hours other than the evening peak-load hours. ENS is observed from 8 AM when the electricity demand starts to increase before the morning peak. Penetration of renewables, mainly wind in Germany, is also correlated with the appearance of medium and small domains in the analysis. As shown in Figure 89 medium and small domains limit CWE exchanges in a large part of hours with ENS.

DISTRIBUTION OF THE ENS AMONG THE DIFFERENT DOMAINS AND THE HOURS OF THE DAY FOR THE WINTER 2018-19 'BASE CASE' (FIG. 90)

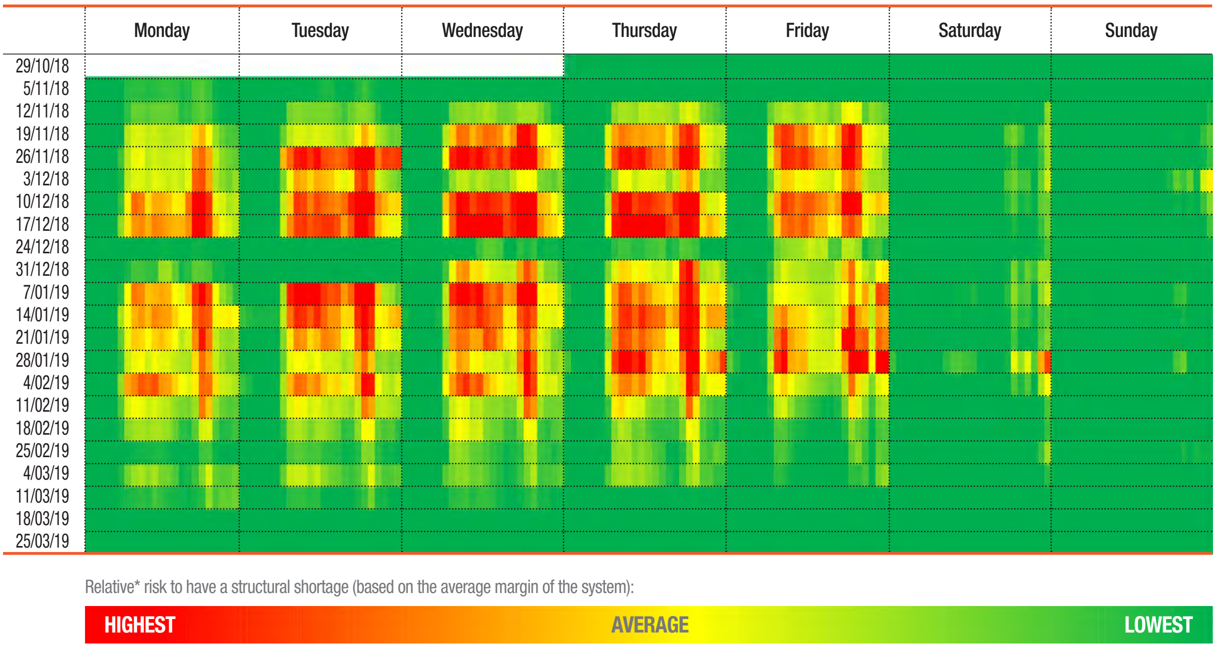




6.1.1.3. WHEN IS A STRUCTURAL SHORTAGE RISK IDENTIFIED?

Given the low-probability of having an hour of structural shortage in the 'base case' scenario, the risk of structural shortage has been calculated based on the hourly remaining margin on the Belgian thermal units. Figure 91 was constructed for didactic purposes and makes it possible to clearly identify those times when the risk of structural shortage is the highest. The colour legend shows the relative risks (structural shortages are more likely to happen in hours that are coloured red than hours that are coloured green). In general, the risk follows the country's residual demand (demand minus nondispatchable 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 2018-19 IN THE 'BASE CASE' SCENARIO BASED ON THE HOURLY REMAINING MARGIN ON THE BELGIAN THERMAL UNITS (FIG. 91)



Note that the probability to have a structural shortage for the winter 2018-19 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.

The graphs shown in this section are based on the outputs of the simulations for the 'base case' scenario for winter 2018-19.

It is important to mention that the values of these figures can change for the other simulations performed in this study as the amount of LOLE and ENS will be different for different simulations. 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 shortage and the available capacity in all simulated countries.

6.1.1.4. MARKET RESPONSE IMPACT ON ADEQUACY

The market response assumptions used in the 'base case' scenario are explained in section 3.3. The available market response capacity for winter 2018-19, amounting to 702 MW, is taken into account with constraints on the number of activations and their duration, as described in section 3.3.

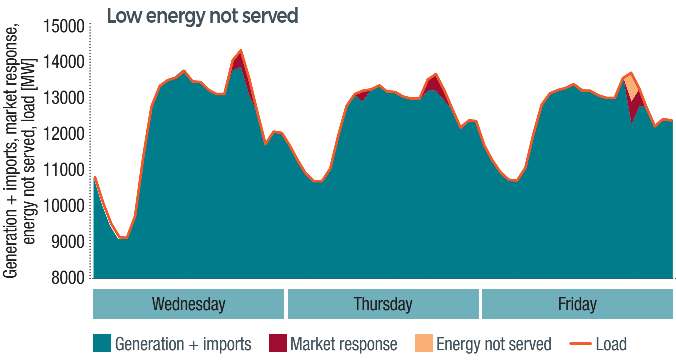
Figure 92 (above) shows three days of the simulation during which a relatively small structural shortage occurs. In such situations, market response helps to cover the shortages. It can be seen that market response makes it possible to cover energy not served, resulting in no structural shortage during three consecutive situations. This was possible because the number of hours when market response was needed was limited, and the energy that had to be served was below the market response capacity. However, later in that week there are still remaining hours that cannot be covered due to the imposed limitations on the number of activations of such volume taken into account in this study.

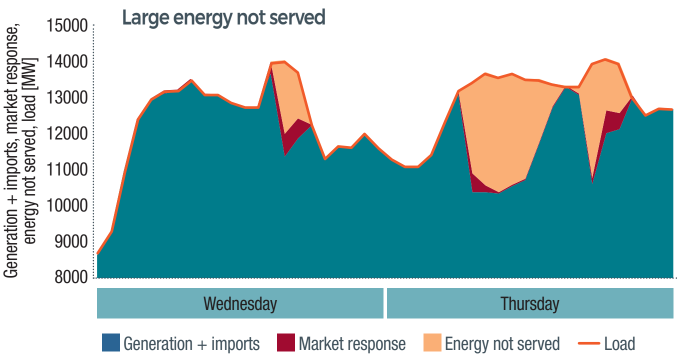
Figure 92 (below) shows a more extreme situation during the same days of another week where larger volumes of structural shortages occur for several consecutive hours. In such situations, market response is of little help to cover the total energy not served, but will still help to reduce the peaks. Increasing the market response capacity in such cases will also not help, unless the limitations on the volume are also reduced.

6.1.1.5. SCARCITY SITUATIONS IN NEIGHBOURING COUNTRIES WHILE THERE IS STRUCTURAL SHORTAGE IN BELGIUM

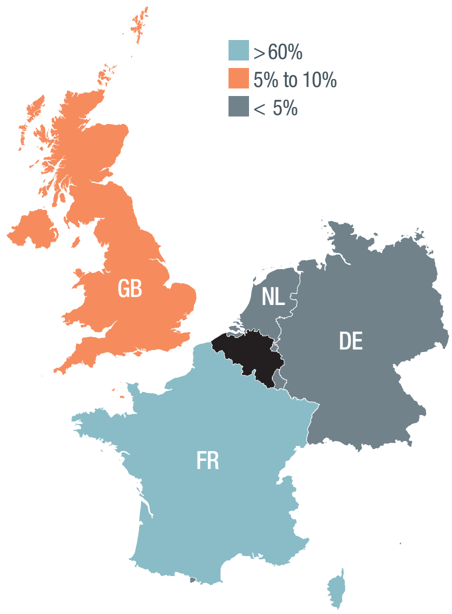
The ability to find energy abroad when there is structural shortage in Belgium is crucial for the Belgium's security of supply, due to Belgium's high dependence on imports for its own adequacy. This ability for Belgium to obtain sufficient imports in situations of structural shortage will be reduced if its neighbours are also experiencing adequacy problems at the same time. The likelihood of scarcity problems in neighbouring countries in case of a structural shortage in Belgium is shown in Figure 93 for winter 2018-19. The high probability of France, over 60%, indicates that scarcity situations between France and Belgium are highly correlated. Great Britain has a 5% to 10% probability of encountering an adequacy issue at the same time as Belgium. For the Netherlands and Germany, the occurrence of scarcity situations when scarcity occurs in Belgium is low (lower than 5%).

ILLUSTRATION OF THE IMPACT OF MARKET RESPONSE IN BELGIUM (FIG. 92)





PROBABILITY TO HAVE ENS WHEN BELGIUM EXPERIENCES ENS (FIG. 93)



6.1.2. OUTLOOK FOR WINTERS 2019-20 AND 2020-21

The main changes for winter 2019-20 compared to winter 2018-19 that are included in the 'base case' assumptions are:

- The integration of the Nemo Link® interconnector between Great Britain and Belgium. It is assumed that the Nemo Link® interconnector does not introduce any distortions in the shape of the flow-based domains for winter 2019-20 with respect to the ones used in the 'base case' for winter 2018-19;
- Assumed decommissioning of several Turbojets in Belgium (90 MW);
- Assumed decommissioning of Wilmarsdonk CHPs (129 MW);
- Assumed decommissioning of Angleur (50 MW) and Izegem (20 MW) units;
- Large-scale decommissioning of coal plants in Great Britain: approximately 4000 MW in 2019-20.

Figure 96 compiles the results for winter 2019-20 according to the 'base case' assumptions. The LOLE average is 30 minutes and the ENS is equal to 0.7 GWh on average. P95 values are equal to 2h for LOLE and 1.5 GWh for ENS. A margin of 1700 MW according to the average criteria and 1800 MW according to the P95 criteria are identified. Taking into account the most restrictive criterion (the average), this results in a margin of 1700 MW.

The number of activations of a possible volume of strategic reserve would be very low (0.2 on average) and the maximum number of activations observed in all the future states would be seven times per year. The maximal activation length would be as much as 14 hours in case of structural shortage.

WINTER 2019-20 – 'BASE CASE' (FIG. 94)

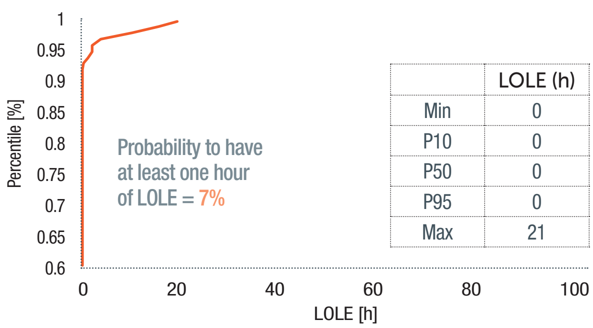
	AVERAGE	P95
LOLE [h]	0h30	2h00
ENS [GWh]	0.7	1.5
Need [+] or Margin [-] [MW]	-1700	-1800

→ Margin of 1700 MW

	AVERAGE	P95	MAX
Amount of activations	0.2	1	7
Activation lenght [h]	1.9	2	14

The LOLE distribution for the futures states obtained for the winter 2019-20 'base case' is shown in Figure 95. The maximum amount of LOLE obtained in the most extreme future state simulated (most extreme winter from the total set of winters) is 21 hours. The probability of having a structural shortage is 7%. This means that for 93% of the simulated winters, there is no LOLE observed (and therefore LOLE in P50 and P90 is also 0).

WINTER 2019-20 – 'BASE CASE' CUMULATIVE DISTRIBUTION OF LOLE WITHOUT STRATEGIC RESERVE (FIG. 95)



	LOLE (h)
Min	0
P10	0
P50	0
P95	0
Max	21

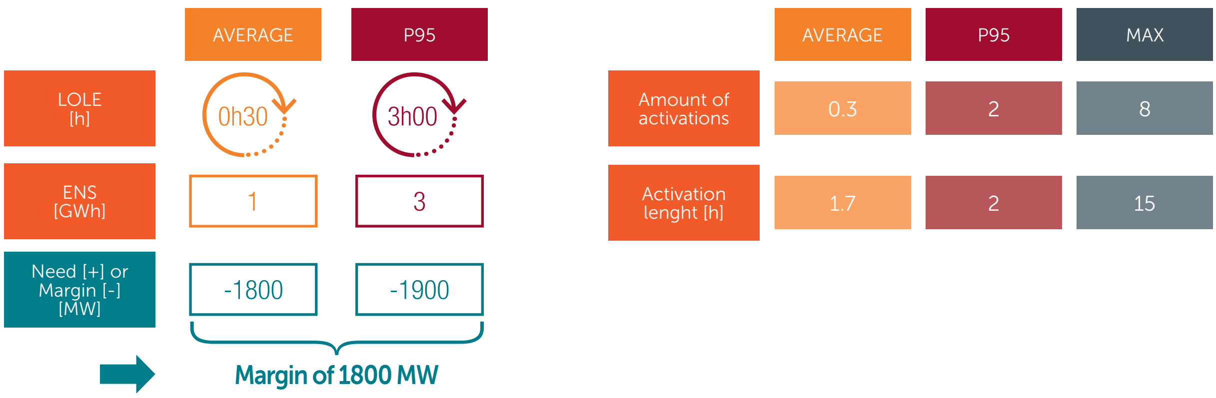
Relatively small changes are assumed for Belgium between winter 2019-20 and winter 2020-21. In additional, for winter 2020-21, the following points are worth mentioning:

- Further large decommissioning of coal plants in Great Britain is expected: approximately additional 4000 MW in 2020-21;
- The planned HVDC interconnector between Germany and Belgium (ALEGrO) has a target commissioning date of 2020. Given the current uncertainty about its exact commissioning date as well as to the way it needs to be modelled within the flow-based market coupling, the ALEGrO interconnector is not part of the 'base case' analysis for winter 2020-21.

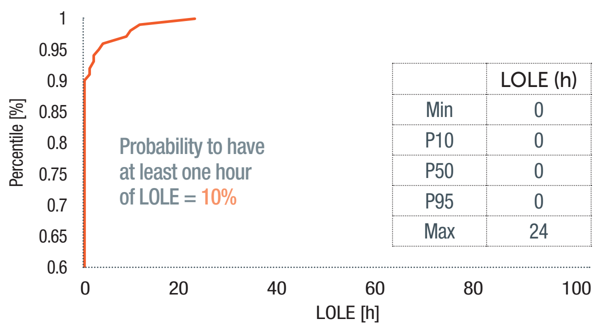
With these assumptions, a margin of 1800 MW is identified for Belgium for winter 2020-21. The LOLE average is 30 minutes and the LOLE in P95 is equal to three hours, as shown on Figure 96. The number of activations is very low (0.3 on average) and the maximum observed in all the future states is eight times per year. The maximal activation length can be as much as 15 hours in case of structural shortage.

The cumulative distribution and percentiles are given in Figure 97. There are still 10% of the simulated future states that have a risk of structural shortage in winter 2020-21. The maximum amount of LOLE obtained in the most extreme future state simulated (most extreme winter from the total set of winters) for winter 2020-21 is 24 hours.

WINTER 2020-21 – 'BASE CASE' (FIG. 96)



WINTER 2019-20 – 'BASE CASE' CUMULATIVE DISTRIBUTION OF LOLE WITHOUT STRATEGIC RESERVE (FIG. 97)



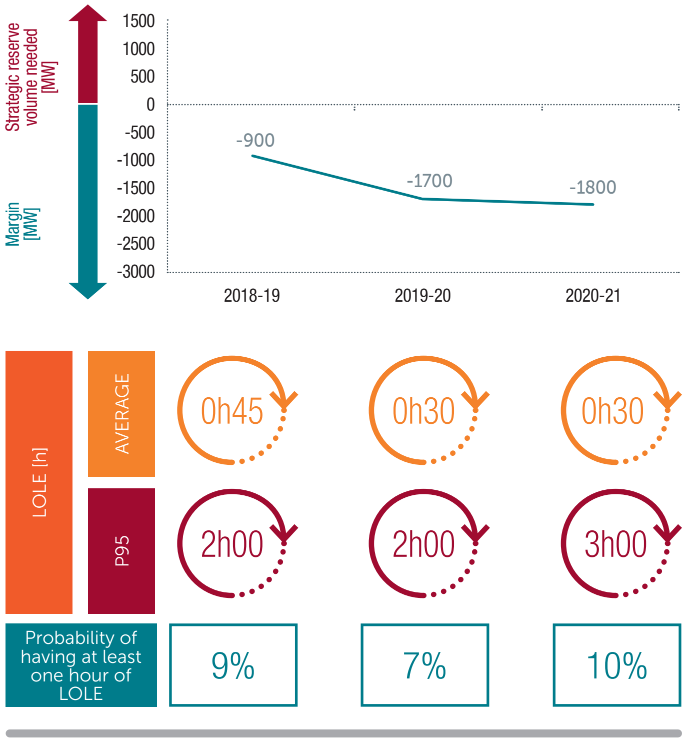
6.1.3. SUMMARY OF THE RESULTS FOR THE ‘BASE CASE’ SCENARIO

Figure 98 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 900 MW in winter 2018-19 rises to 1700 MW in winter 2019-20 and increases slightly to 1800 MW for the next winter 2020-21.

The LOLE average remains below one hour for all three winters. The LOLE P95 is two hours for winter 2018-19 and winter 2019-20 and increases to three hours for winter 2020-21. Lastly, the probability of having a structural shortage hour is 9%, 7% and 10% for winter 2018-19, 2019-20 and 2020-21 respectively.

ADEQUACY INDICATORS FOR THE ‘BASE CASE’ SCENARIO (FIG.98)



6.2 SENSITIVITY ON NUCLEAR AVAILABILITY AND CONFIGURATION OF THE DROGENBOS POWER PLANT AS CCGT

To provide a complete view of the adequacy of the Belgian system, it is important to also quantify low-probability events with a high-impact on Security of Supply. Therefore, on top of the analysis of the 'base case' scenario which was presented in section 6.1, Elia studied a specific sensitivity for nuclear availability in Belgium and France combined with the configuration of the Drogenbos power plant as CCGT. Section 6.2.1 provides more details for this sensitivity, together with the elements that justify the analysis of the sensitivity. Next, in section 6.2.2 and section 6.2.3, the results of the sensitivity are given for the Drogenbos power plant as OCGT and CCGT respectively.

6.2.1. DESCRIPTION OF THE SENSITIVITIES ANALYSED

Due to the large installed capacity of Belgian nuclear reactors (five out of the seven Belgian reactors have an installed capacity of approximately 1 GW), their availability has a significant impact on Belgian adequacy. In section 3.1.3.2, the unusual outages that occurred for Belgian nuclear power plants between 2014 and 2017 were already mentioned. Given the unusual nature of those outages, the decision was made not to include them in the forced outage rates of the 'base case' scenario. However, given their significant impact, it is important to analyse a scenario taking into account such events. Therefore, a detailed comparison of the availability modelled in the 'base case' with the Belgian nuclear availability experienced in the last five winters was conducted (see Figure 99).

COMPARISON OF THE BELGIAN P95 NUCLEAR AVAILABILITY AS MODELLED IN THE 'BASE CASE' SCENARIO WITH THE HISTORICAL P95 NUCLEAR AVAILABILITY OF THE LAST FIVE WINTERS (FIG. 99)

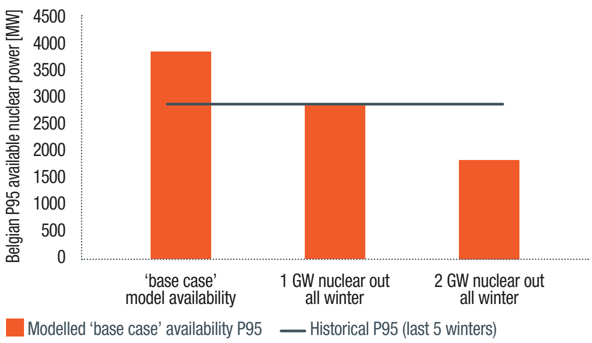


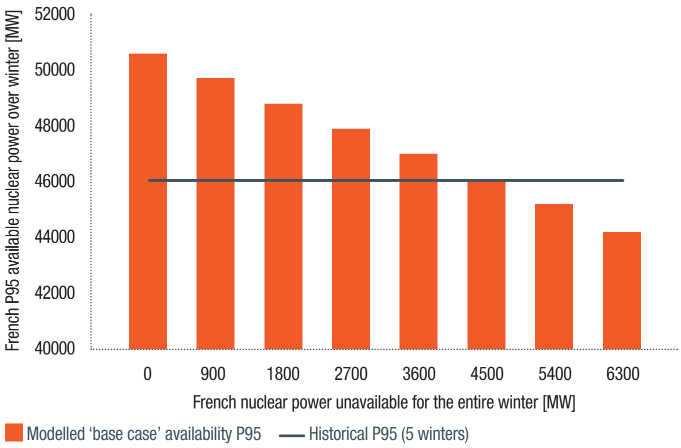
Figure 99 gives the P95 modelled Belgian nuclear availability for the 2018-19 'base case' scenario. As mentioned in section 3.1.3.2, this availability also takes into account the planned maintenance for the final months of 2018. When comparing the model P95 indicator with the same indicator as experienced over the last five winters, it becomes apparent that the 'base case' modelled availability is highly optimistic in terms of the P95 indicator.

The P95 nuclear availability power indicator is then calculated when 1 GW and 2 GW, respectively, of nuclear production capacity is removed for the entire winter from the 'base case' scenario (middle and right bars in Figure 99). This indicator is then compared with the same indicator as experienced over the last five winters (horizontal line in Figure 99).

As a result of this analysis, it is concluded that low-probability, high-impact events, as observed during the last five winters, can be properly captured by assuming a sensitivity with 1 GW of nuclear production capacity out of service for the entire winter in Belgium. This is demonstrated in Figure 99, with the P95 nuclear availability modelled for this sensitivity being in line with the P95 availability experienced over the past five winters.

The same analysis was conducted for French nuclear availability, see Figure 100. When comparing the French P95 nuclear availability modelled in the 'base case' with the historical French nuclear availability of the last five winters, it became apparent that a sensitivity with 4.5 GW of nuclear production capacity out for the entire winter in France should be considered in order to bring the P95 modelled availabilities in line with the experienced availabilities over the last winters in France.

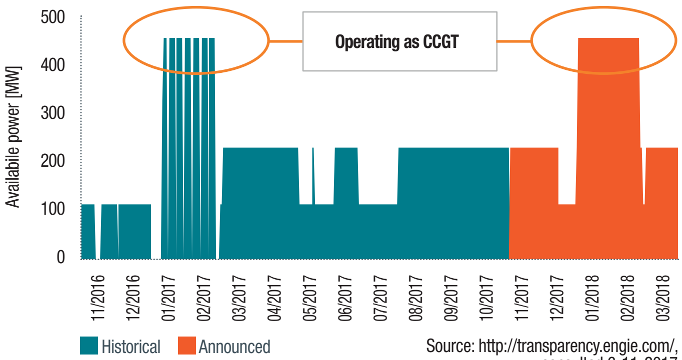
COMPARISON OF THE FRENCH P95 NUCLEAR AVAILABILITY AS MODELLED IN THE 'BASE CASE' SCENARIO WITH THE HISTORICAL P95 NUCLEAR AVAILABILITY OF THE LAST FIVE WINTERS (FIG. 100)



It should be noted that the abovementioned calculated outages for the entire winter, for both France and Belgium, come on top of the outages already modelled for the rest of the generation park for both countries in the 'base case' simulation.

As mentioned in section 3.1.3.1, the 'base case' scenario takes the Drogenbos power plant into account as an OCGT production unit with a capacity of 230 MW. However, the production unit can also operate in a CCGT configuration with a capacity of 460 MW, as can be observed in Figure 101. The figure gives the available capacity for the Drogenbos generation unit for the period between November 2016 and March 2018, as communicated on the transparency platform of its owner Engie. The Drogenbos power plant seems to be systematically made available as a CCGT unit in January and February (in which the bulk of the energy not served is identified). Therefore, a sensitivity has also been studied on the operation of the Drogenbos power plant as CCGT for the entire winter with a production capacity of 460 MW, in combination with the abovementioned sensitivity on Belgian and French nuclear availability.

HISTORICAL & ANNOUNCED AVAILABILITY OF THE DROGENBOS POWER PLANT (FIG. 101)



Source: http://transparency.engie.com/, consulted 6-11-2017

6.2.2. RESULTS FOR THE SENSITIVITY FOR REDUCED NUCLEAR AVAILABILITY WITH DROGENBOS IN OCGT OPERATING MODE

Figure 102 shows the results of the low-probability, high-impact sensitivity in which

- 1 GW of Belgian nuclear capacity, as well as 4.5 GW of French nuclear capacity was considered out of service for winter 2018-19
- Drogenbos is operating in OCGT mode

With these assumptions, **a need for a strategic reserve of 600 MW is identified**. In Figure 102, the LOLE average and LOLE P95 are shown for the case without any strategic reserve. A LOLE of 4 hours 30 minutes and LOLE P95 equal to 50 hours are found. A strategic reserve volume of 600 MW is needed in order to reach the adequacy criteria for Belgium. The number of activations is 0.8 on average and the maximum number of activations observed in all the future states is 17 times per year. The maximal activation length can be as much as 42 hours in case of structural shortage.

WINTER 2018-19 – SENSITIVITY WITH 1 GW NUCLEAR OUT IN BELGIUM AND 4.5 GW NUCLEAR OUT IN FRANCE, COMBINED WITH DROGENBOS AS OCGT (FIG. 102)

	AVERAGE	P95
LOLE [h]	4h30	50h00
ENS [GWh]	6.8	61.9
Need [+] or Margin [-] [MW]	300	600

Strategic reserve volume of 600 MW needed

	AVERAGE	P95	MAX
Amount of activations	0.8	7	17
Activation lenght [h]	4.4	16	42

In Figure 103, the cumulative distribution of the LOLE without any strategic reserve is given. The figure also indicates that the probability of experiencing at least one hour of loss of load in Belgium is 14% for winter 2018-19 in this case. The maximum amount of LOLE obtained in the most extreme future state simulated in this sensitivity is 88 hours.

WINTER 2018-19 – SENSITIVITY WITH 1 GW NUCLEAR OUT IN BELGIUM AND 4.5 GW NUCLEAR OUT IN FRANCE, COMBINED WITH DROGENBOS AS OCGT CUMULATIVE DISTRIBUTION OF LOLE WITHOUT STRATEGIC RESERVE (FIG. 103)

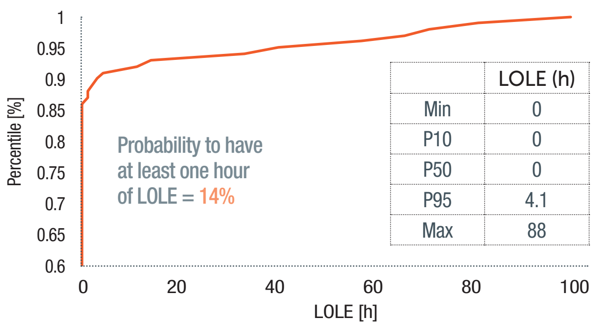


Figure 104 gives an overview of the results of this sensitivity for the Belgian and French nuclear fleet for the next three winters. The need for a strategic reserve of 600 MW for winter 2018-19 is strongly reduced to a relatively small need of 100 MW for both winter 2019-20 and winter 2020-21. However, the probability of having at least one hour of LOLE (without any strategic reserve) in a winter increases from 14% in winter 2018-19 to 15% and 18% respectively for winter 2019-20 and winter 2020-21.

SENSITIVITY WITH 1 GW NUCLEAR OUT IN BELGIUM AND 4.5 GW NUCLEAR OUT IN FRANCE, COMBINED WITH DROGENBOS IN OCGT OPERATING MODE (FIG. 104)

	Winter 2018-19		Winter 2019-20		Winter 2020-21	
	AVERAGE	P95	AVERAGE	P95	AVERAGE	P95
LOLE [h]	4h30	50h00	3h15	20h30	3h15	23h00
ENS [GWh]	6.8	61.9	5.9	31.5	7.0	34.0
Probabilty to have at least one hour of LOLE	14%		15%		18%	
Need [+] or Margin [-] [MW]	300	600	100	100	100	100

6.2.3. RESULTS FOR THE SENSITIVITY WITH REDUCED NUCLEAR AVAILABILITY IN COMBINATION WITH DROGENBOS IN CCGT OPERATING MODE

The sensitivity for Belgian and French nuclear availability, the results of which are discussed in section 6.2.2, was also analysed in combination with a CCGT operation of the Drogenbos power plant for the entire winter. The CCGT operating mode of the Drogenbos power plant results in 460 MW of available production capacity, compared to 230 MW when operating in OCGT mode. The results for this sensitivity are given in Figure 105 for winter 2018-19. The LOLE average and LOLE P95 shown correspond to the case without any strategic reserve. The values found, LOLE average equal to 3 hours 45 minutes and LOLE P95 equal to 42 hours respectively, are thus above the adequacy criteria. The sensitivity with the CCGT operating mode for the Drogenbos power plant then results **in a need for strategic reserve of 500 MW** for winter 2018-19, compared to a need of 600 MW with the OCGT operating mode for the power plant.

Figure 106 gives, for this sensitivity, the cumulative distribution of the LOLE for the situation without any strategic reserve. The figure also indicates that the probability of having at least one hour of LOLE (without any strategic reserve) is 12%.

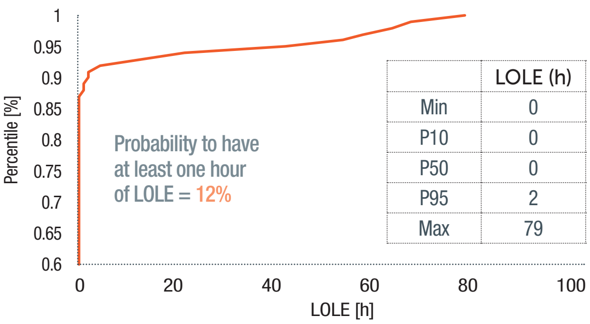
WINTER 2018-19 – SENSITIVITY WITH 1 GW NUCLEAR OUT IN BELGIUM AND 4.5 GW NUCLEAR OUT IN FRANCE, COMBINED WITH DROGENBOS AS CCGT (FIG. 105)

	AVERAGE	P95
LOLE [h]	3h45	42h00
ENS [GWh]	5.7	42.7
Need [+] or Margin [-] [MW]	300	500

→ Strategic reserve volume of 500 MW needed

	AVERAGE	P95	MAX
Amount of activations	0.7	7	18
Activation lenght [h]	4.0	16	19

WINTER 2018-19 – SENSITIVITY WITH 1 GW NUCLEAR OUT IN BELGIUM AND 4.5 GW NUCLEAR OUT IN FRANCE, COMBINED WITH DROGENBOS AS CCGT CUMULATIVE DISTRIBUTION OF LOLE WITHOUT STRATEGIC RESERVE (FIG. 106)



	LOLE (h)
Min	0
P10	0
P50	0
P95	2
Max	79

In Figure 107, an overview of the results for the next three winters is given for the sensitivity with reduced nuclear production capacity in Belgium and France combined with the CCGT operating mode of the Drogenbos power plant. In contrast to winter 2018-19, the Belgian adequacy criteria are both satisfied for winter 2019-20 and winter 2020-21. Whereas no margin can be identified for winter 2019-20, a margin of 100 MW is identified for the winter 2020-21. The probability to have at least one hour of LOLE increases from 12% for winter 2018-19 to 15% and 19% respectively for winters 2019-20 and 2020-21.

SENSITIVITY WITH 1 GW NUCLEAR OUT IN BELGIUM AND 4.5 GW NUCLEAR OUT IN FRANCE, COMBINED WITH DROGENBOS IN CCGT OPERATING MODE (FIG. 107)

	Winter 2018-19		Winter 2019-20		Winter 2020-21	
	AVERAGE	P95	AVERAGE	P95	AVERAGE	P95
LOLE [h]	3h45	42h00	2h45	18h30	2h30	16h30
ENS [GWh]	5.7	42.7	5.0	19.2	4.7	14.8
Probabilty to have at least one hour of LOLE	12%		15%		19%	
Need [+] or Margin [-] [MW]	300	500	0	-100	-100	-100

07 CONCLUSIONS

This report gives an estimate of the needed capacity of strategic reserve in order to maintain Belgium's adequacy, in compliance with the criteria defined by law for winter 2018-19. Outlooks for winters 2019-20 and 2020-21 are also given. If no volume is identified, the margin for each scenario was also calculated.

Elia performed a probabilistic analysis following the timetable set out in the law to allow the Federal Minister of Energy to take a decision on the volume needed by 15 January 2018.

The assumptions used in this report were defined mid-October 2017, taking into account remarks received during the public consultation on input data. The assumptions include the best available estimates for installed generation capacities in Belgium and neighbouring countries at the time of collecting the inputs.

'BASE CASE' SCENARIO:

The **'base case' scenario** - as it is called in this study - describes the most likely change in the Belgian generation facilities given the information that Elia collected, which was discussed with FPS Economy prior to 15 October 2017 as requested by law and submitted to a public consultation ending on 18 September 2017. It includes the following assumptions (only the main drivers for Belgium are listed below):

- Relatively limited growth of 0.5% per year of Belgium's total demand;
- Full availability of nuclear units (normal forced outage rates were taken into account, without accounting for exceptional outages as experienced over the last five years);
- photovoltaic and onshore wind forecasts based on the latest data from the regions, combined with a best estimate made by Elia and FPS Economy for offshore wind;
- A maximum simultaneous import capacity of 4500 MW is considered for Belgium from the CWE countries for all winters;
- A maximum simultaneous import capacity of 4500 MW for Belgium for winter 2018-19, increasing to 5500 MW for winters 2019-20 and 2020-21;
- The commissioning of the new interconnector with Great Britain (Nemo Link®) with a capacity of 1000 MW from winter 2019-20 onward;
- Stable trend for the remaining thermal generation facilities in Belgium between winter 2017-18 and winter 2018-19, with a small decrease in thermal capacity for both winter 2019-20 and winter 2020-21. The assumptions for winter 2018-19 are fixed as units had to announce their closure before 31 July 2017.

For the 'base case' scenario, as defined in this report, the need for strategic reserve is equal to 0 MW, as a **margin of 900 MW** was obtained for Belgium.

SENSITIVITY TO THE BELGIAN AND FRENCH NUCLEAR AVAILABILITY:

To capture the consequences of low-probability, high-impact events, an analysis of French and Belgian historical nuclear availability was conducted. From this analysis, it was observed that the modelled nuclear availability of the 'base case' scenario does not sufficiently take into account the unusual unavailability of Belgian and French nuclear units that occurred during recent winters. Therefore, the decision was made to analyse a sensitivity in which the Belgian and French nuclear availability is aligned with that of the last five winters.

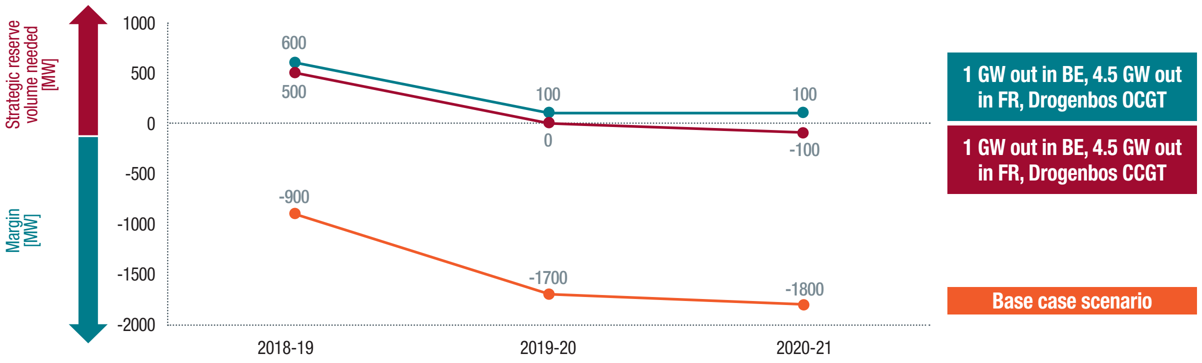
For Belgium, a sensitivity in which 1 GW of nuclear production capacity is out of service for the entire winter (on top of the normal forced outage rates as simulated in the 'base case' model) makes it possible to correctly align the modelled P95 availability with the historical availability of the last five winters. For France, the same analysis resulted in 4.5 GW of nuclear production capacity considered unavailable for the entire winter.

SENSITIVITY TO THE OPERATION OF THE DROGENBOS POWER PLANT AS CCGT:

In May 2016, the Drogenbos power plant changed its operational mode from CCGT to OCGT, resulting in a reduction of production capacity from 460 MW to 230 MW. During winter 2016-17, however, it was observed that the unit changed its normal OCGT operational mode to CCGT. Furthermore, as announced[36] by the owner of the Drogenbos plant (Engie), the same conversion is planned for part of winter 2017-18. Therefore, the sensitivity to Belgian and French nuclear availability was also combined with a sensitivity to the operation of the Drogenbos power plant as CCGT.

36. http://transparency.engie.com

RESULTS FOR THE 'BASE CASE' SCENARIO, AS WELL AS FOR THE SENSITIVITIES ON BELGIAN AND FRENCH NUCLEAR AVAILABILITY FOR DROGENBOS OPERATING BOTH AS CCGT AND OCGT (FIG. 108)



The results of the 'base case' scenario, as well as the two sensitivities described above, are given in Figure 108 for the three winters analysed.

RESULTS FOR WINTER 2018-19:

For the 'base case' scenario both adequacy indicators are satisfied for winter 2018-19, and a margin of 900 MW is identified for the Belgian system. However, the sensitivities capturing nuclear availability in line with that of the last five winters exhibit a need for strategic reserve. This sensitivity results in a strategic reserve need of 600 MW when considering the OCGT operating mode of the Drogenbos power plant, and a need of 500 MW when Drogenbos is considered as operating the entire winter as CCGT.

TRENDS FOR WINTERS 2019-20 AND 2020-21:

Results for winters 2019-20 and 2020-21 show an increase in the margin for all the scenarios for Belgium (and therefore a decrease in the risk of having a structural shortage). The main driver for this is the introduction of the Nemo Link® interconnector, which is taken into account for both winters. The contribution of the Nemo Link® interconnector is slightly countered by a relatively moderate decommissioning of units in Belgium assumed for those winters compared to winter 2018-19.

It should also be noted that the integration of the ALEGrO interconnector in the flow-based market coupling operations was not yet considered in the 'base case' analysis of winter 2020-21. A more detailed assessment for winter 2019-20 will be provided in next year's analysis.

IN ADDITION TO THESE RESULTS, SOME POINTS OF ATTENTION CAN BE DERIVED FROM THIS STUDY:

- Belgium remains dependent on imports for its security of supply. This means that any change in the assumptions for neighbouring countries has a potential impact on the results for Belgium.
- The calculations are made without taking into consideration the maintenance of thermal units in Belgium for the winter (maintenance for year 2018 is taken into account as per the latest planning but only for winter 2018-19). Elia, in consultation with Belgian producers, aims to maximally schedule maintenances outside of the winter period. This also applies to the maintenance and construction/ upgrades works of main grid elements, critical for the network infrastructure of Elia.
- As a results, all of these interventions are typically scheduled to occur outside the winter months. Furthermore, the announcement of units leaving the market also occurs outside the winter period. Both previously mentioned elements can cause that i) the scheduling and planning of these operations becomes more critical and ii) can lead to difficult moments for the supply outside the winter period (November – March).

Elia recommends taking a decision on the basis of the scenarios incorporating low-probability events with a high-impact on Belgian adequacy. Concretely, this results in a need for 500 MW or 600 MW of strategic reserve depending on whether the Drogenbos power plant is operating in CCGT or OCGT mode for the entire winter.

MEDIUM AND LONGER TERM OUTLOOK:

With respect to the medium term (2025) and longer term (2030 and beyond) outlook, Elia would like to refer to its report 'Electricity Scenarios for Belgium towards 2050' published on 15 November 2017. In this report Elia analyses both short-term and long-term policy options for Belgium's future energy mix on the path towards 2050. Bearing in mind the planned nuclear phase-out in 2025, Elia is striving for a sustainable and adequate electricity system with prices that are competitive compared to our neighbouring countries.

In each future scenario for 2050 there is a need for additional adjustable (thermal) generation capacity in order to cope with the shock of the nuclear exit and guarantee security of supply. To guarantee an adequate electricity system, it is necessary - in all future scenarios - to build replacement capacity. Based on the assumptions in that study, in the event of a full nuclear exit by 2025, Belgium must develop at least 3.6 GW of new capacity that will come online by no later than winter 2025-2026. In calculating this 3.6 GW, Elia paid particular attention to energy efficiency, demand-side management, energy storage and the expected increase in renewable energy. It was also assumed that in 2025 there will be at least 2.3 GW of existing gas-fired power stations (both CCGT and OCGT).

WHEN INTERPRETING THE RESULTS ONE SHOULD TAKE INTO ACCOUNT THE FOLLOWING KEY ASSUMPTIONS:

- The calculated volume of strategic reserve does not differentiate between reductions in demand or additional production capacity. The volume is calculated on the assumption that this volume is 100% available. This is an important hypothesis, especially for large volumes;
- The volume is calculated without taking into account the possibility of being able to actually find this volume 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 mentioned in this report. Elia cannot guarantee that these assumptions will actually materialise. In most cases, these are developments beyond the direct control or responsibility of the system operator.

08

APPENDIX 1: SIMULATION OF THE WESTERN-EUROPEAN ELECTRICITY MARKET

This appendix provides a general overview of how the simulation of the Western-European electricity market was conducted for this analysis. In section 8.1, we elaborate on the construction of the 'Monte-Carlo' years, which serve as input for the actual simulation. Next, we describe in detail how the market simulation is conducted and we elaborate on the tool used in section 8.2.

8.1 CONSTRUCTION OF THE 'MONTE-CARLO' YEARS

A probabilistic risk analysis requires the construction of a large number of future states. Each of these states can then be analysed to determine the adequacy indicators. We begin this section by indicating **which variables are taken into account** (section 8.1.1). Next, we illustrate how both **electricity production** (section 8.1.2) and **electricity consumption** (section 8.1.3) are modelled in general. Finally, section 8.1.4 elaborates on how the different variables are **combined into 'Monte-Carlo' years**.

8.1.1. VARIABLES TAKEN INTO ACCOUNT FOR THE SIMULATION

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 following **climatic variables**:

- hourly time series for **wind energy generation**;
- hourly time series for **PV**[37] **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 thermal generation facilities** on the basis of which samples can be taken regarding power plants' unavailability.

37. PV: photovoltaic.

CORRELATION OF CLIMATIC CONDITIONS

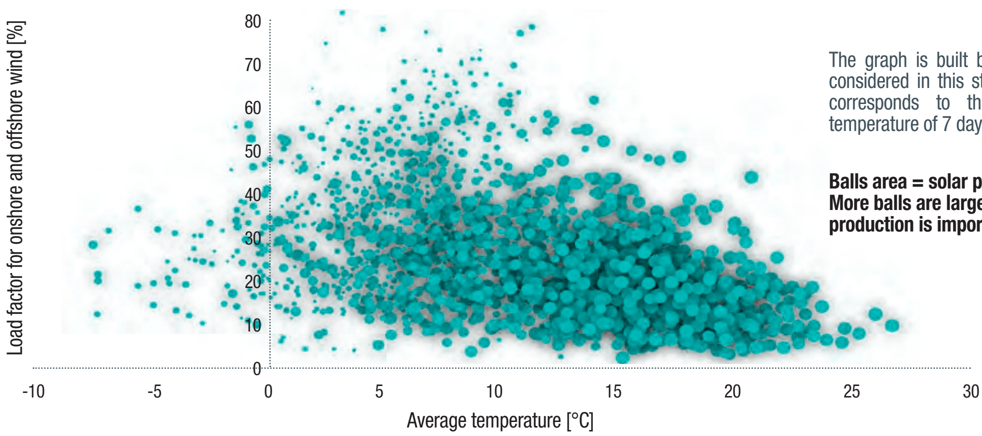
The various meteorological conditions having an impact on renewable generation and electricity consumption are not independent of each other. Wind, solar radiation, temperature and precipitation are correlated for a given region. In general, high-pressure areas are characterised by clear skies and little wind, while low-pressure areas have cloud cover 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 109 attempts 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 113);
- 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 the occurrence of a tight situation due to a cold spell which first spreads 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 variable sources that is installed each year in Europe and the high sensitivity to temperature of some countries' electricity demand, it is essential to maintain the various geographically and time-correlated weather conditions in the assessment.

CORRELATION BETWEEN WIND PRODUCTION, SOLAR PRODUCTION AND TEMPERATURE (AVERAGE OF 7 DAYS) (FIG. 109)



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

Balls area = solar production. More balls are large, more the solar production is important.

The climatic variables in this study are modelled on the basis of 33 historical winters, namely those between 1982 and 2015. The historical data for temperature, wind production, and solar production are procured in the context of ENTSO-E. These data are used *inter alia* in the ENTSO-E MAF (see section 1.8.4) and the ENTSO-E TYNDP market simulations.

For the modelling of the hydroelectric power production, Elia has performed an analysis based on statistical data provided by TSOs to ENTSO-E combined with precipitation data from the NCDC[38] database of the United States [18]. For years 1991 to 2015, the hydroelectric power generation data come from ENTSO-E data portal [34]. The data for the other years, i.e. from 1982 to 1990, are reconstructed on the basis of the historical precipitation data for each country (NCDC).

The availability data for Belgian **thermal generation** facilities comes from a historical analysis based on the years from 2007 to 2016 (see section 3.1.3.2). For the other countries, the unavailability data come from the ENTSO-E studies [16], [27], [34] and/or data from bilateral contacts with TSOs.

The climatic conditions are modelled using 33 (historical) climatic winters.

VARIABLES (FIG. 110)

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

38. NCDC: National Climatic Data Centre.

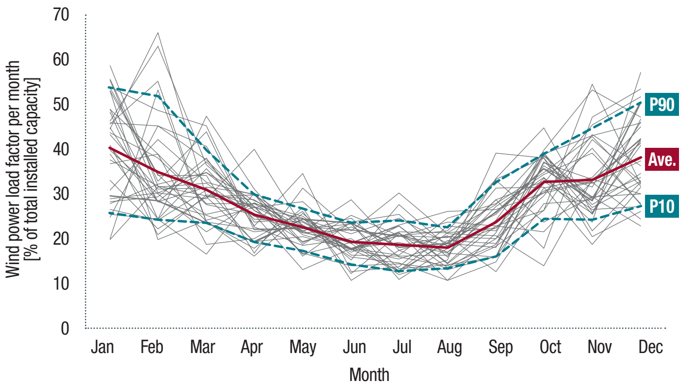
VARIABILITY OF WIND ENERGY PRODUCTION

Wind energy production depends on the wind speed where the wind turbines are located. Figure 111 shows the wind power load factor each month[39] for the 34 historical years based on which the 33 winters used in the assessment are created. 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.

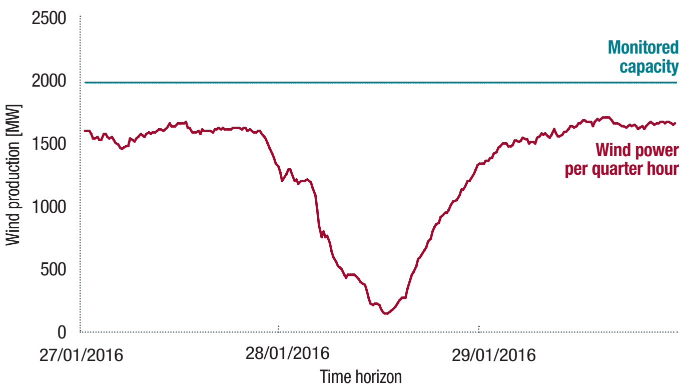
In addition to the variability depending on the month, wind energy production may fluctuate considerably across the same day, as illustrated by Figure 112.

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 electricity demand.

VARIABILITY OF ONSHORE WIND POWER PER MONTH IN BELGIUM ON THE BASIS OF 34 HISTORIC YEARS (FIG. 111)



HISTORIC EXAMPLE OF THE WIND GENERATION VARIABILITY PER DAY (FIG. 112)



VARIABILITY OF PV SOLAR GENERATION

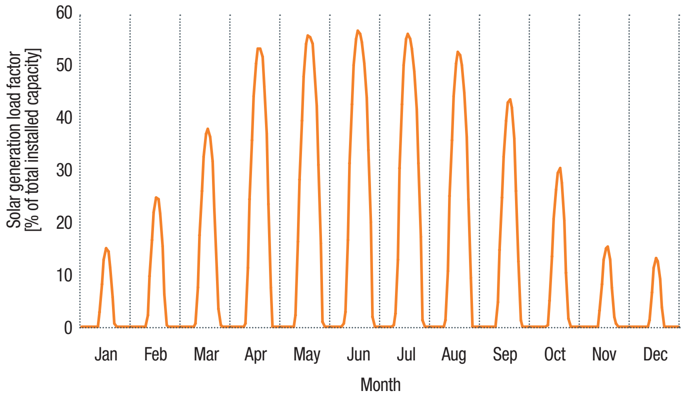
PV solar generation is subject to sunshine variability. The average level of generation is higher in the summer than in the winter:

- the number of 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 the sky being covered by clouds) 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 113 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 generation level is zero during the winter peaks because by then the sun has already gone down.

AVERAGE HOURLY LOAD FACTOR PER MONTH FOR BELGIUM (FIG. 113)



39. 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.

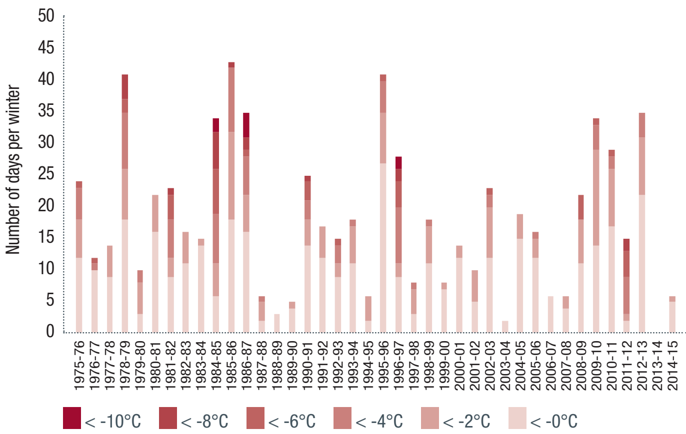
VARIABILITY OF TEMPERATURE

The temperature is decisive in determining the risk of a structural shortage due to the sensitivity of electricity demand to temperature; the colder the weather, the higher the level of electricity consumption (see section 8.1.3).

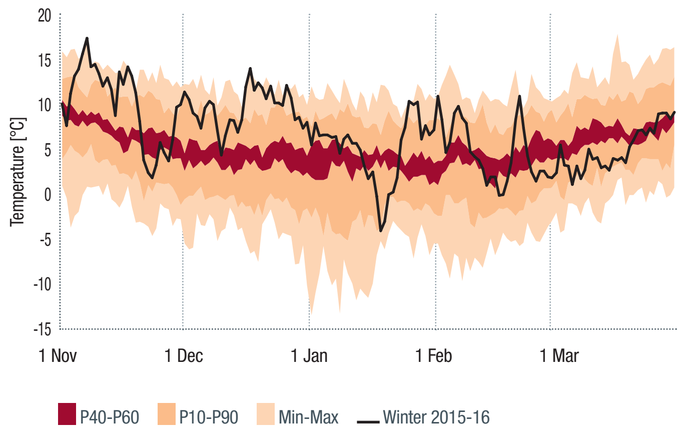
Figure 114 shows, for every winter between 1975 and 2015, the number of days when the average day temperature was below 0˚C (as measured at the Royal Meteorological Institute in Uccle). The colour code indicates how far below zero this was (the darker the colour, the lower the temperature).

Figure 115 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 spells can also take place in other months.

WINTER SEVERITY (BASED ON THE AVERAGE DAILY TEMPERATURE IN UCCLE) (FIG. 114)



DISTRIBUTION OF THE DAILY TEMPERATURE IN BELGIUM FOR THE WINTERS BETWEEN 1975 AND 2015 (FIG. 115)



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:

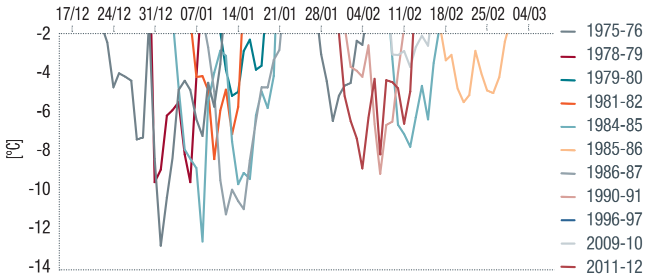
- the low temperature during this period dropped at least twice to below -7 ˚C;
- the high temperature remained below 0 ˚C for 3 days during the period to.

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 defines 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 116 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. 116)



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

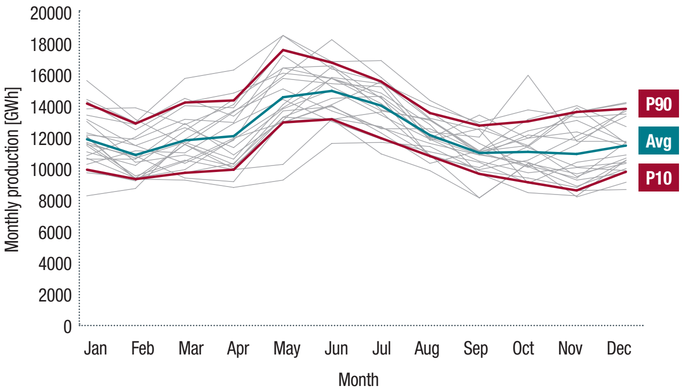
VARIABILITY OF HYDROELECTRIC POWER GENERATION

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 compared to an average precipitation or wet year.

Figure 117 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.

HISTORICAL MONTHLY HYDRAULIC PRODUCTION FROM 1991 TO 2015 IN THE CWE AREA + SWITZERLAND (EXCLUDING PUMPED-STORAGE) (FIG. 117)



VARIABILITY IN THE AVAILABILITY OF 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. For more information concerning the exact modelling, see section 8.1.2.2.

Other variables (see below) might have a potential impact on security of supply but are disregarded in the 'base case' of this study. However, some events listed below are taken into consideration as a sensitivity for this study.

The simulations performed in this study disregard, in the 'base case', 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.).

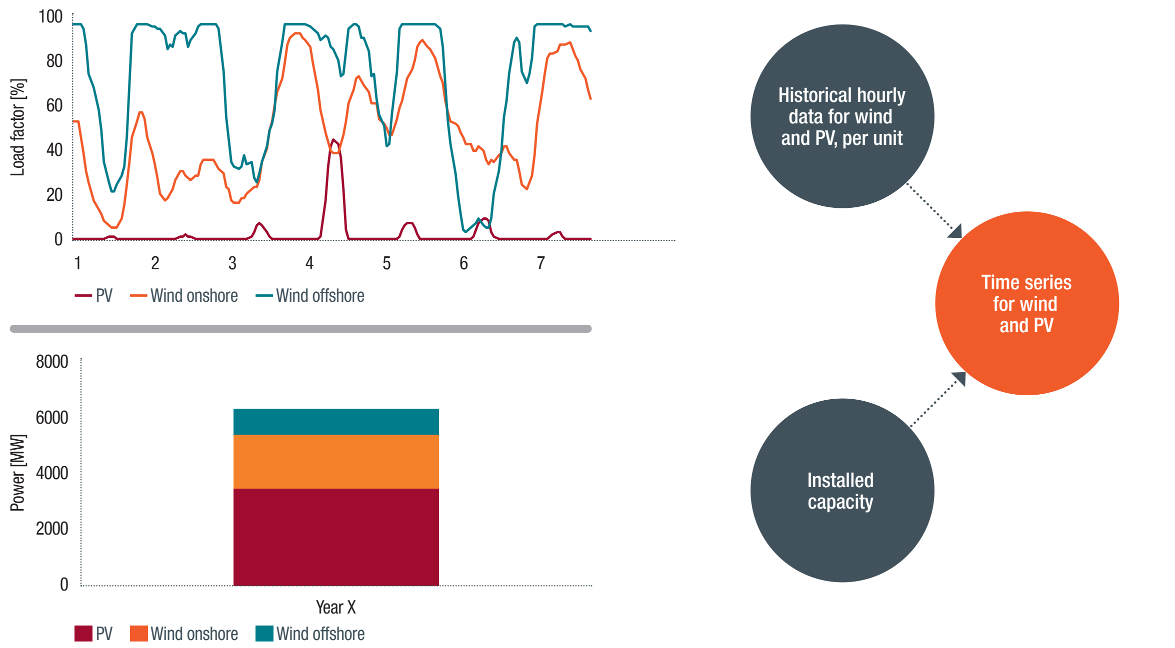
8.1.2. MODELLING OF ELECTRICITY PRODUCTION

This section elaborates on the modelling of electricity generation for use in market simulations. First, section 8.1.2.1 discusses the modelling of wind and solar electricity production. Second, both the modelling of individually modelled thermal production (section 8.1.2.2), and profiled thermal production (section 8.1.2.3) are elaborated upon. Third, the modelling details of hydroelectric power production are given in section 8.1.2.4

8.1.2.1 WIND AND SOLAR ELECTRICITY PRODUCTION

As already indicated in 8.1.1, hourly wind energy production and solar generation data used are historical data for these production types. The forecasts of installed capacity for each simulated country are combined with this historical data to obtain production time series for onshore wind, offshore wind and photovoltaic production. This process is illustrated in Figure 118.

PRODUCTION TIME SERIES FOR WIND AND PV (FIG. 118)



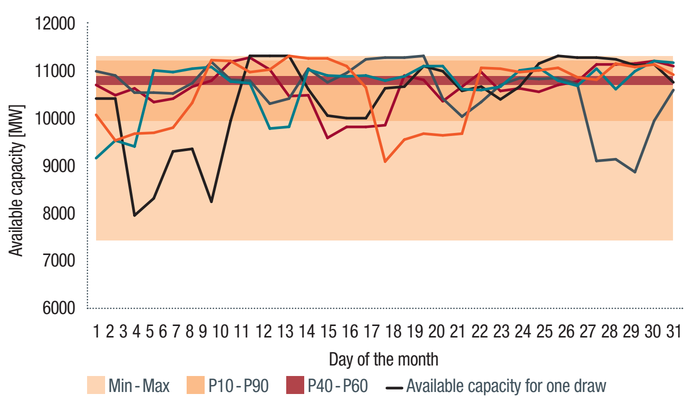
8.1.2.2. INDIVIDUALLY MODELLED THERMAL PRODUCTION

Large thermal production units, independent of their production types, are modelled individually, with their specific technical and economic characteristics. Their individual availability is determined by a probabilistic draw for each 'Monte Carlo' year (see section 8.1.4) 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.

Figure 119 shows an example of a distribution of various samples for thermal units with individual modelling (see section 8.1.2.2) 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).

ILLUSTRATION OF AN INDIVIDUALLY MODELLED THERMAL PRODUCTION PARK AFTER DRAW OUTAGE DRAWS FOR ONE MONT (FIG. 119)



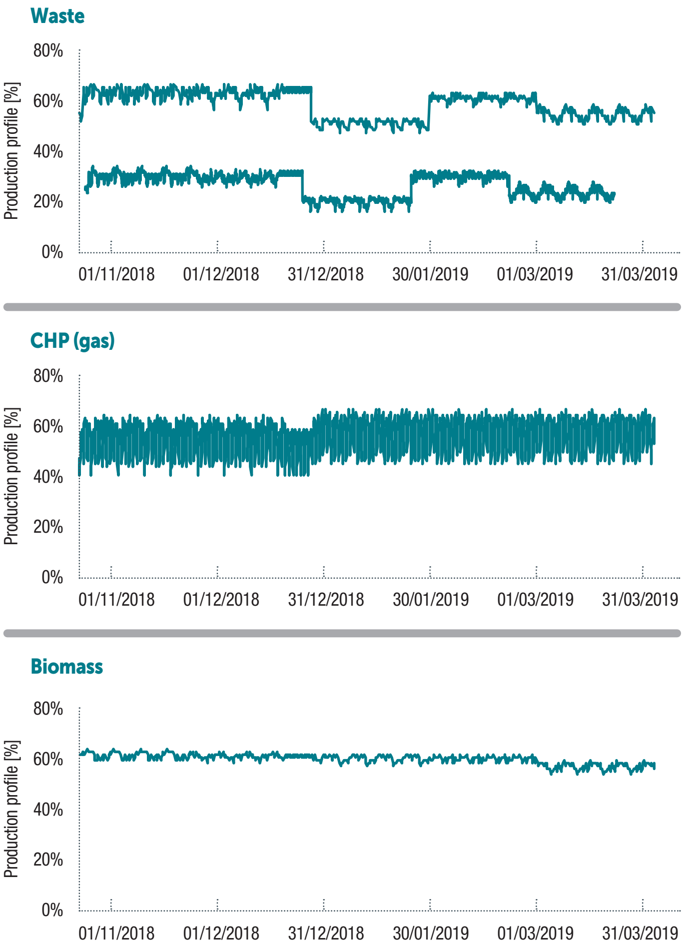
8.1.2.3. PROFILED THERMAL PRODUCTION

Small thermal production units are modelled in an aggregated way by using a fixed production profile. Examples of such small thermal production units are small biomass installations or Combined Heat and Power (CHP) production units. The availability of these smaller units is directly taken into account into the production profile, and is therefore the same for all 'Monte Carlo' years. The different production profiles for each country are collected through bilateral contacts or within the context of ENTSO-E.

Specific Belgian characteristics in the modelling of profiled thermal production

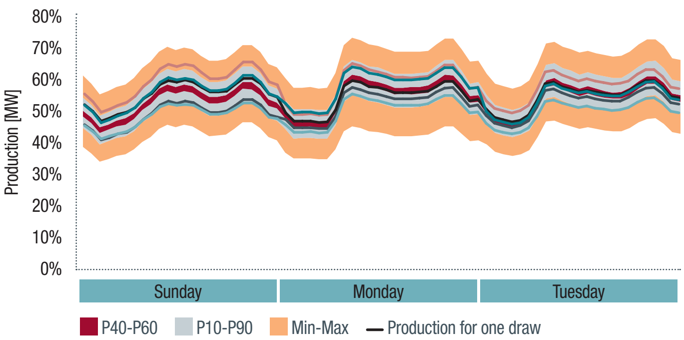
For Belgium, the units without a CIPU contract are modelled through profiles. However, in contrast to the modelling of profiled thermal production of other countries, different availability among 'Monte Carlo' years is taken into account for these units. Three production types are differentiated in the Belgian profiled thermal production: biomass, CHP and waste. For each of these three profiled 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 120. These profiles have also been made public in the public consultation on the data used in this analysis.

HOURLY AVERAGE WASTE PRODUCTION PROFILE FOR THE WINTER (FIG. 120)



Based on an analysis of the availability of each of the three production categories, probabilistic outage draws are done in a way similar to what 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 121, 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. 121)



8.1.2.4. HYDROELECTRIC POWER PRODUCTION

Three types of hydroelectric power production are taken into account:
- pumped-storage;
- run-of-river;
- reservoir power production.

The first two types of hydroelectric power production are present in Belgium, whilst the last type is more common in countries with more natural differences in elevation.

Pumped-storage power production functions by pumping water to higher reservoirs when electricity is cheap, and by turbining this water back to lower reservoirs when electricity is more expensive. An efficiency for the round-trip process of 75% is taken into account in the modelling. Depending on the size of the pumped-storage reservoirs as well as their operating mode, their dispatch can differ. The model differentiates between pumped-storage production units which optimise their dispatch on a daily basis and those which optimise their dispatch on a weekly basis.

A more classic form of hydroelectric power production converts energy of a natural water flow into electricity. If a **reservoir** is present, the energy can be stored for a specific amount of time, allowing it to be dispatched at the economically best moment. These reservoirs are taken into account into the simulation model, together with their inflows. If no reservoir is present, the production type is called **run-of-river**, and no arbitrage can be effected when the power is injected into the grid. This type of hydroelectric power production is modelled through the use of profiles.

8.1.3. MODELLING OF ELECTRICITY CONSUMPTION

The hourly total electrical load of each 'Monte Carlo' year for each simulated market node is forecast for the period under study. Electricity consumption profiles are constructed in a way a similar to that for all simulated market nodes[40] and can be divided into the three separate steps shown in Figure 122.

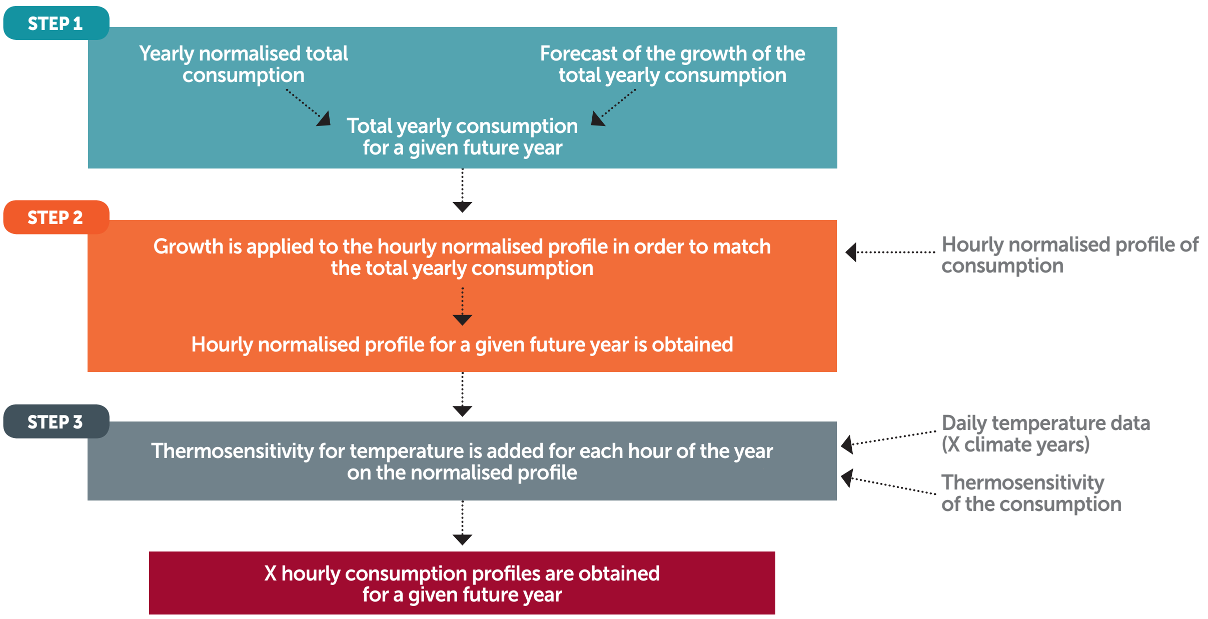
STEPS TO CONSTRUCT CONSUMPTION PROFILE (FIG. 122)

1. GROWTH OF THE TOTAL DEMAND
2. GROWTH APPLIED TO AN HOURLY PROFILE NORMALISED FOR TEMPERATURE
3. ADDITION OF THE TEMPERATURE SENSITIVITY EFFECT TO THE NORMALIZED LOAD

The process constructs one hourly total load profile per market node for each climatic condition, resulting, in the case of this study, in demand profiles corresponding to 33 historical winters (see section 8.1.1). Figure 123 gives a detailed overview of the construction process of the hourly load profiles. The three separate steps are detailed respectively in section 8.1.3.1, section 8.1.3.2 and section 8.1.3.3.

Elia has aligned its method for electricity load modelling with the method developed in the context of the ENTSO-E adequacy study MAF. This improves coherence among different studies and allows for efficient continuous development of the method.

CONSTRUCTION OF THE HOURLY CONSUMPTION PROFILES (FIG. 123)



40. An exception is made for France in the current analysis. Please refer to section 4.1.2 for more information.

8.1.3.1. GROWTH OF THE TOTAL DEMAND

1 GROWTH OF THE TOTAL DEMAND

The first step consists of forecasting the annual total electrical load for a given country. After normalising the most recent historical total load for temperature, an estimate 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). By applying the forecast growth of total demand on the most recent historical total load, normalised for temperature, a forecast of future total load is obtained.

8.1.3.2. GROWTH APPLIED TO AN HOURLY PROFILE NORMALISED FOR TEMPERATURE

2 GROWTH APPLIED TO AN HOURLY PROFILE NORMALISED FOR TEMPERATURE

Once the total annual normalised demand has been forecast for the future years, a normalised hourly consumption profile corresponding to a future year can be constructed. In order to compute it, the electricity consumption profile of the country in question 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, called the profile normalised for temperature, is then scaled in order to meet the forecast total demand determined in the first step. Several methods can be used to construct a profile normalised for temperature. The method used in this analysis was developed in the context of the ENTSO-E adequacy study MAF (see section 1.8.4).

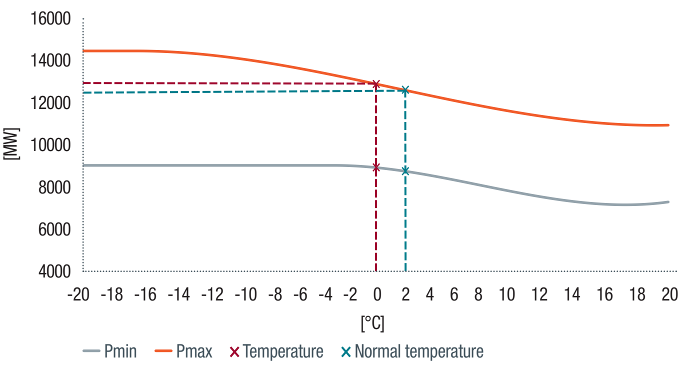
8.1.3.3. ADDITION OF THE TEMPERATURE SENSITIVITY EFFECT TO THE NORMALISED LOAD

3 ADDITION OF THE TEMPERATURE SENSITIVITY EFFECT TO THE NORMALIZED LOAD

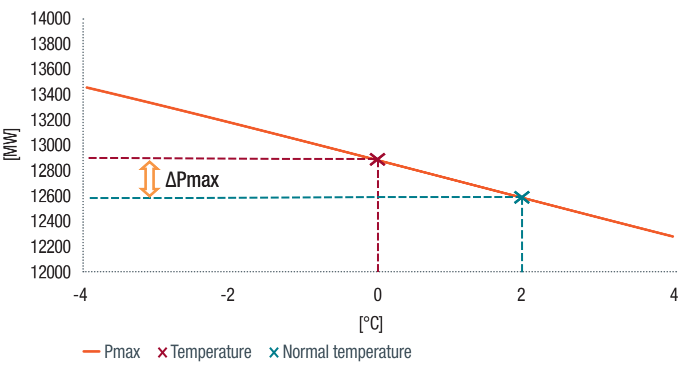
For each hour, the temperature sensitivity effect is applied to the normalised load profile. In the context of the ENTSO-E MAF study, a new methodology for incorporating the temperature sensitivity of the load has been developed. This new method relates the daily minimal and maximal power to the daily temperature (average over 24 hours). A cubic relationship is used make it possible to capture in systematic way effects like saturation when temperatures become very low. Elia has chosen to implement this new method, developed in the context of ENTSO-E, for the analysis of winter 2018-19. This makes its possible to determine the volume of strategic reserve in order to be more consistent with the methods developed at the European level.

Figure 124 illustrates the load's cubic sensitivity to temperature. The sensitivity for both the maximal (Pmax) and minimal (Pmin) daily load are given. In Figure 125, the incorporation of the temperature effect into the maximal daily load is illustrated. For a day which has a normal temperature of 2°C and for which the historical temperature of 0°C is simulated, the daily maximal temperature of the normalised profile is increased by ΔPmax.

CUBIC SENSITIVITY OF THE LOAD TO TEMPERATURE (FIG. 124)



CUBIC SENSITIVITY OF THE LOAD FOR TEMPERATURE: DETAIL (FIG. 125)



8.1.4. 'MONTE CARLO' SAMPLING AND COMPOSITION OF CLIMATIC YEARS

The variables discussed in section 8.1.1 are combined so that the correlation between the various renewable energy sources (wind, solar, hydroelectric) and the temperature remains. Both geographical and time correlations are present.

Consequently, 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 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. Availability thus differs thus for each future state. Since each 'Monte Carlo' year carries the same weight in the assessment, the different availability samples have equal probability of occurrence.

WHAT PERFORMS THE 'MONTE CARLO' METHOD?

The '**Monte Carlo' method** is used in various domains, including **probabilistic risk assessments**. 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 by 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 126).

The **deterministic approach** considers that a unique state is associated with each system input. This means that the same output will independently provide 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 do not exist or are too difficult to implement and can be described via four steps:

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

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

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

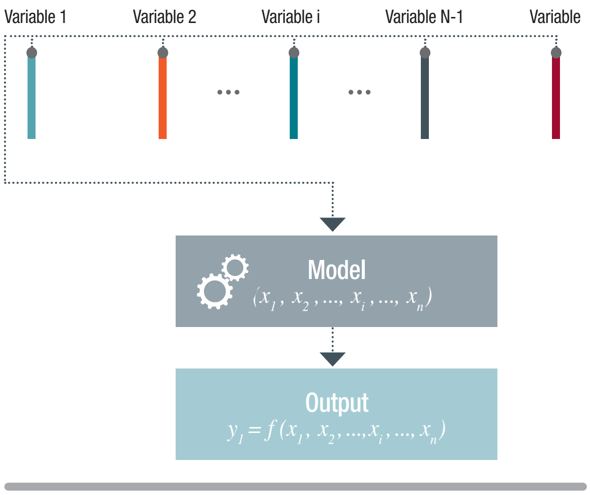
$$Input = \{x_{1,i}, x_{2,i}, ..., x_{p,i}\}$$

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

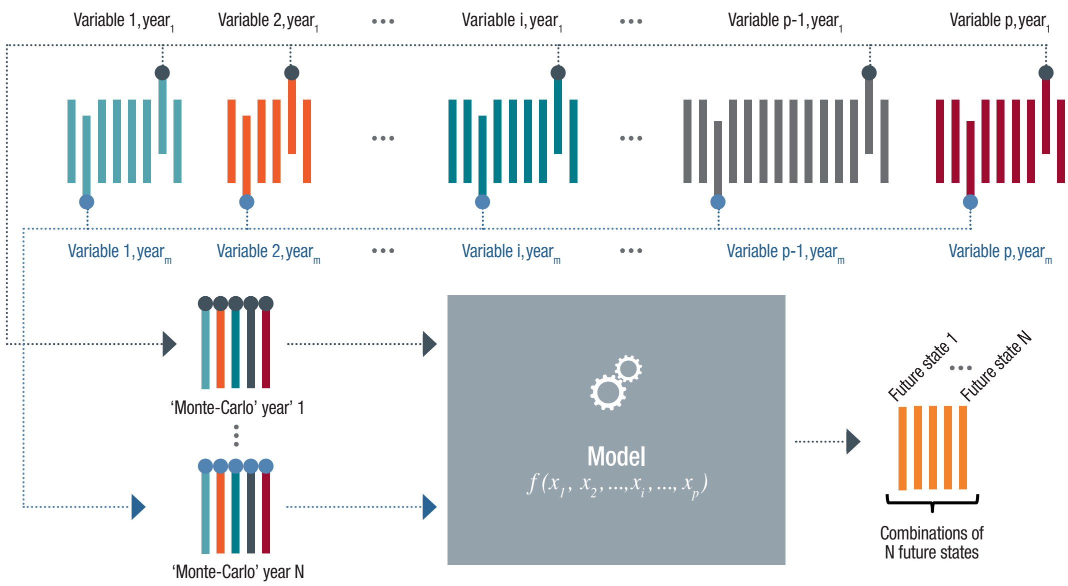
4) **Step 4:** Iterate steps 2 and 3 for i = 1 to N, where N represent the number of iterations

The **error** for the results arising from the 'Monte Carlo' method decreases as $1/\sqrt{N}$. 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 8.2.1). Figure 127 shows a random sample for p independent variables, yielding N different future states.

BASIC PRINCIPLE BEHIND THE DETERMINISTIC APPROACH (FIG. 126)



A LARGE NUMBER OF RANDOM SELECTIONS ON DIFFERENT VARIABLES ALLOWS TO BUILD THE FUTURE STATES (FIG. 127)



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 must 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.

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 power plants and HVDC forced outages.

8.2 SIMULATION OF EACH 'MONTE-CARLO' YEAR

To simulate the European electricity market, a number of assumptions and parameters must 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 **thermo-sensitivity**;
- 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)).

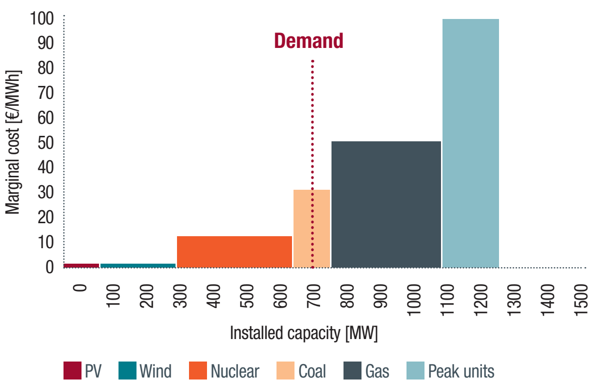
These data are introduced by means of hourly or monthly time series or are established for a whole year.

A detailed modelling of the power plants' economic dispatch is performed. The assessment takes into account the power plants' marginal costs (see Figure 128) and also enables the pumped-storage power plants and hydroelectric reservoirs to be appropriately modelled (see section 8.1.2.4).

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. Demand is considered inelastic in this context. The market response to high prices is also taken into consideration, as explained in section 3.3 for Belgium.

Furthermore in the adequacy assessment, the model also correctly considers that in periods of structural shortage, all of the available generation facilities will be taken into account, operating at their maximum capacity in order to minimise the shortage.

EXAMPLE OF AN ECONOMIC STACK FOR A GIVEN TIME AND A GIVEN PRODUCTION PARK (FIG. 128)



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 commercial exchanges;
- the number of operating hours and revenues of the power plants;
- CO_2 emissions;
- the hourly marginal price for each country.

8.2.1. MODEL USED TO SIMULATE THE ELECTRICITY MARKET

The market simulator used within the scope of this study is ANTARES[41], 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:

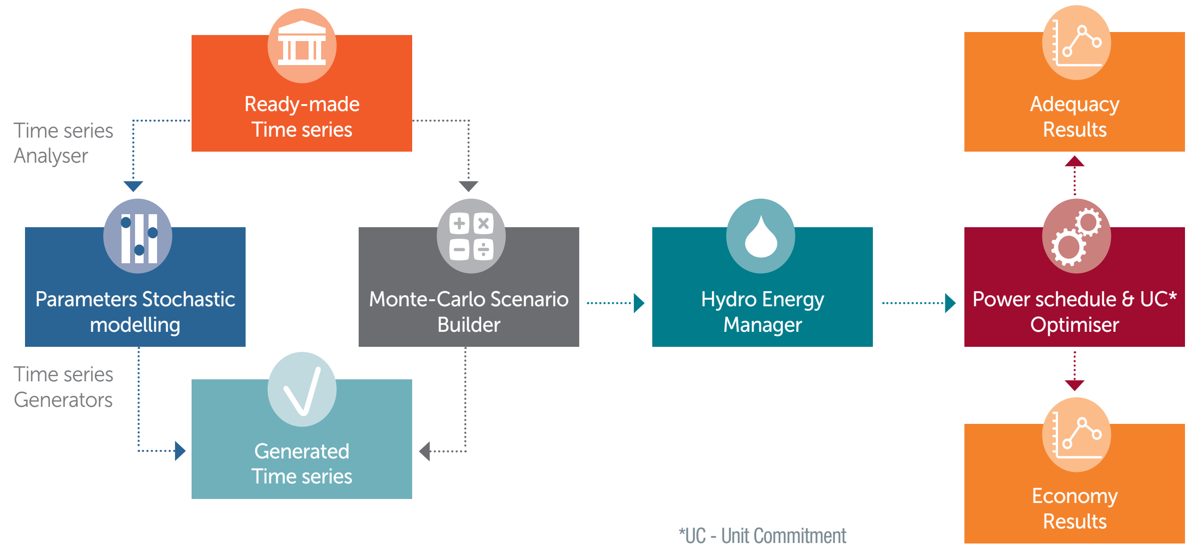
- representation of several interconnected power systems through simplified equivalent models. The European electrical network can be modelled with up to a few hundred of region-sized or country-sized nodes, tied together by edges whose characteristics summarise those of the underlying physical components.;
- sequential simulation with a time span of one year and a time resolution of one hour;
- 8760 hourly time series based on historical/forecast 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 8.1.4). The main process behind ANTARES is summarised in Figure 129 [14].

ANTARES PROCESS (FIG. 129)



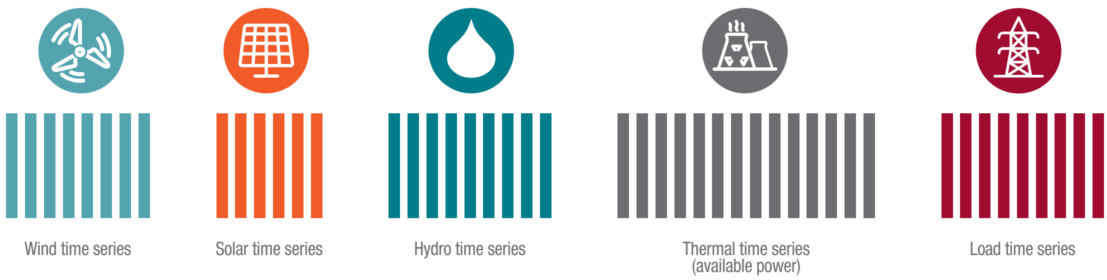
41. ANTARES: A New Tool for Adequacy Reporting of Electric Systems.

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 130). The number of time series for each parameter is usually between 10 to 100 and can be increased if necessary.

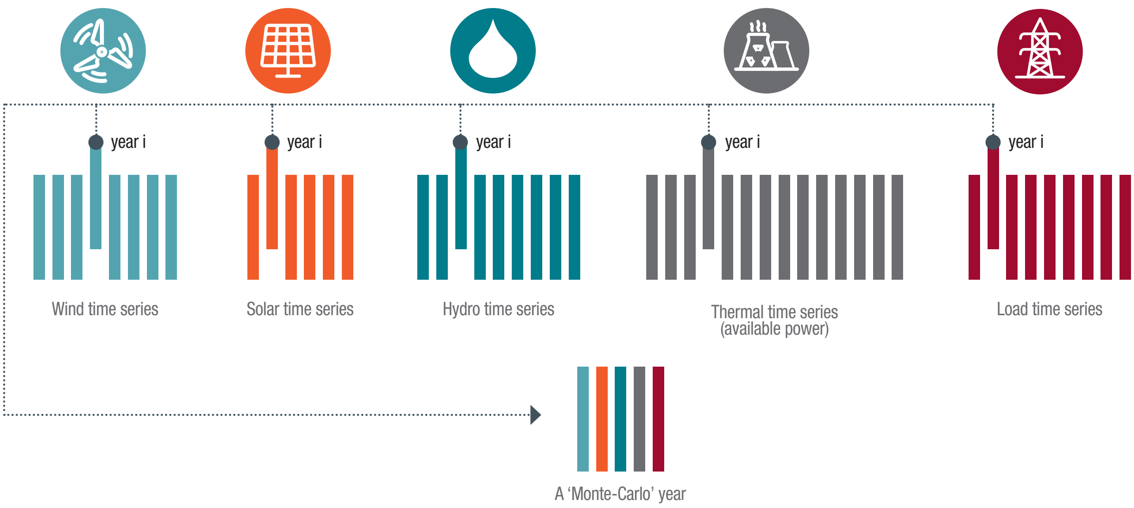
GENERATION OF ANNUAL TIME SERIES FOR EACH PARAMETER (FIG. 130)



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 131.

GENERATION OF A 'MONTE-CARLO' YEAR (FIG. 131)



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.

NB: As described in section 8.1.4., 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 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, using 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 (UC) OPTIMISER

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

The **adequacy study** analyses whether there is enough **available generation power**, following the given state of the system, to meet **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 study** requires **market modelling** in order to determine which plants are delivering power at a given time. This process is carried out via the **economic dispatch** method, where the aim is to minimise the operating cost of the overall system by classically considering a 'perfect market' competition (market bids are based on short-term marginal costs) [14]. The economy study mode is the one used in this assessment.

> 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 published in 2015 [17], and the next version which is expected for publication on January 2018;
- the e-Highway 2050 study [20];
- ENTSO-E's TYNDP[42] [21] and MAF [16];
- RTE French Generation Adequacy Reports [19].

42. TYNDP: Ten Year Network Development Plan.

UNIT COMMITMENT (UC) AND ECONOMIC DISPATCH BASED ON SHORT RUN MARGINAL COSTS

For each 'Monte Carlo' year, ANTARES calculates the most economical unit commitment and generation dispatch, i.e. the one that minimises generation costs while respecting the technical constraints of each generation unit. Dispatchable generation (including thermal and hydro generation) and interconnection flows constitute the decision variables of an optimisation problem whose objective function is to minimise the total operational costs of the system. The optimisation problems are solved with an hourly time step and a weekly time-frame, assuming perfect information at this horizon, but assuming that the change in load and RES is not known beyond that. Fifty-two 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 bound between two Net Transmission Capacity (NTC) values, one for each direction.

Moreover, in ANTARES, some binding constraints on power flows can be introduced. They take form of equalities or inequalities on a linear combination of flows. For instance, they have 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 power plant or a group of power plants with similar characteristics. For each cluster, in addition to 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, two values can be used: a value considered only if the plant is switched on (minimum stable power) and a value which, if higher than 0, forbids the plant from being switched off in the dispatch (must-run). The latter is given on an hourly step time base, whereas the former 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 wind and solar generation.

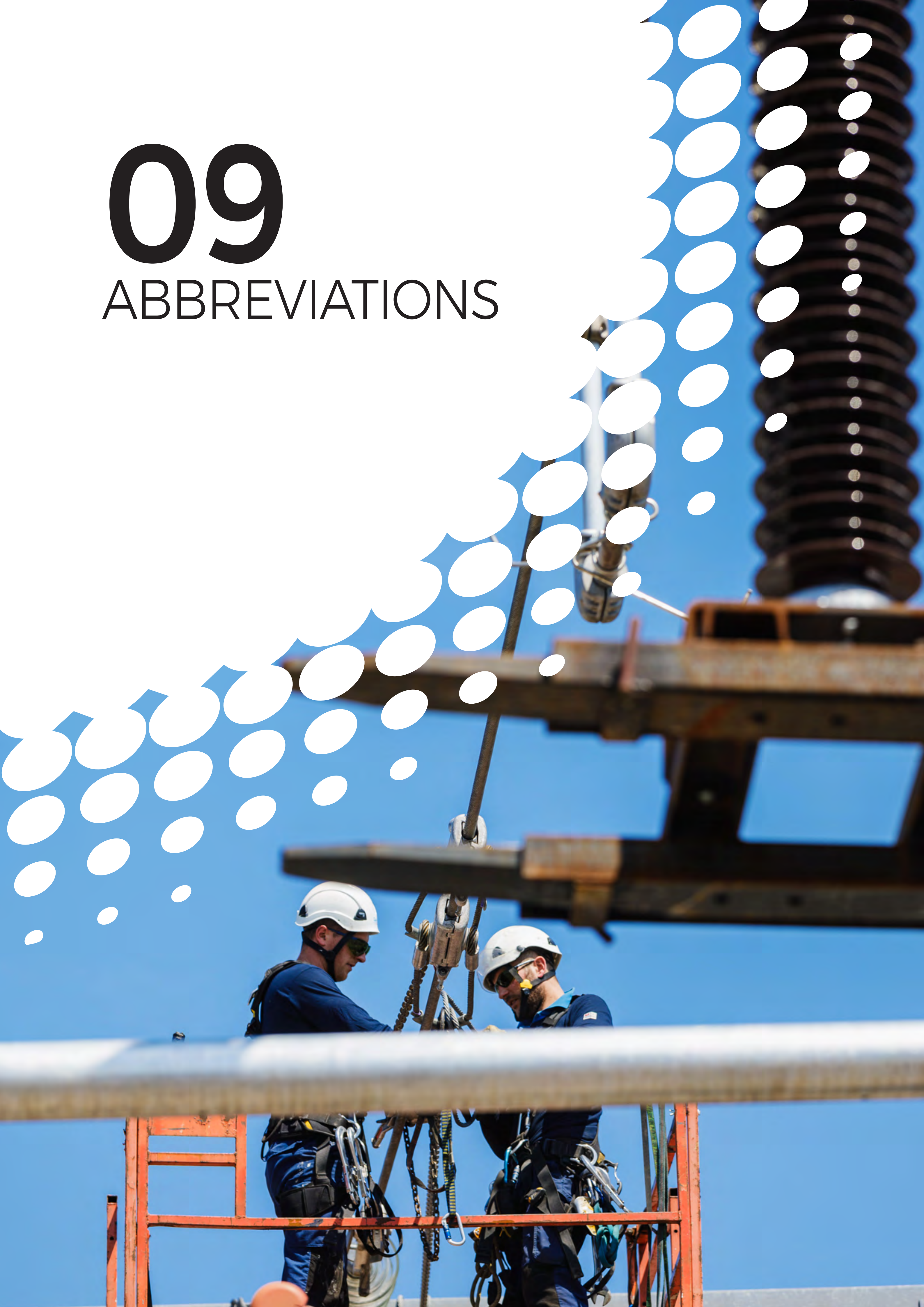
For storage plants, the annual or monthly inflows are first split into weekly amounts of energy (see step 3 in section 8.2.1). The use of this energy is then optimised over the week alongside the other dispatchable units. Each hydro unit can generate up to its maximum capacity.

Pumped-storage plants can pump water which is stored and turbined later. 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 makes it possible to replicate the impact of market response as considered in this study. Activations per day and week can be set for this capacity as binding constraints.

09
ABBREVIATIONS



aFRR: automatic Frequency Restoration Reserve

ANTARES: A New Tool for Adequacy Reporting of Electric Systems

ARP: Access Responsible Party

ASN: Nuclear Safety Agency

BRP: Balance Responsible Party

CASC: Capacity Allocating Service Company

CCG: CWE Consultative Group

CCGT: Combined Cycle Gas Turbine

CEER: Council of European Energy Regulators

CfD: Contracts for Difference

CHP: Combined Heat and 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

CWE: Central West Europe

DG: Directorate-General

DSO: Distribution System Operator

ECN: Energy research Centre of the Netherlands

EMR: Electricity Market Reform

ENS: Energy Not Served

ENS95: Energy Not Served for a statistically abnormal year (95^{th} percentile)

ENTSO-E: European Network of Transmission System Operators for Electricity

EPR: European Pressurised Water 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 (95^{th} percentile)

LOLP: Loss Of Load Probability

LWR: Least Worst Regret

MAF: Mid-term Adequacy Forecast

mFRR: manual Frequency Restoration Reserve

MR: Market Response

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

10 SOURCES

DK(50Hz)
SWE
1305 MW
1395 MW
1743 MW
704 MW
835 MW
756 MW
2103 MW
91 MW
1080 MW
4344 MW
1070 MW
1282 MW

[1] http://economie.fgov.be/nl/ondernemingen/energie/Energiebevoorradingszekerheid/strategische_reserve_elektriciteit/

[2] https://www.ceer.eu/documents/104400/-/-/a9517a5f-5a98-2974-dd61-e085c7971b53

[3] http://www.elia.be/en/products-and-services/Strategic-Reserve/

[4] http://www.elia.be/en/about-elia/newsroom/news/2016/01-12-2016-Adequacy-Study-for-Belgium-the-need-for-strategic-reserve-for-winter-2017-18

[5] http://www.power-in-balance.be/power-indicator-forecast/

[6] http://www.elia.be/en/grid-data/Strategic-Reserve/Status-Activation

[7] http://www.elia.be/~/media/files/Elia/Products-and-services/Strategic-Reserve/SFR-2017-18_NL_final_returntomarket2.pdf (in Dutch)

[8] http://www.elia.be/en/grid-data/balancing/balancing-warnings

[9] http://economie.fgov.be/nl/elektriciteitsschaarste/afschakelplan/ (in Dutch)

[10] http://www.elia.be/en/about-elia/publications/Public-Consultation

[11] http://www.elia.be/en/users-group/Working-Group_Balancing/TF_Strategic_Reserves_Implementation/Agenda

[12] http://www.elia.be/en/about-elia/newsroom/news/2016/20-04-2016-Adequacy-study-flexibility-Belgian-electricity-system

[13] http://www.elia.be/en/about-elia/newsroom/news/2016/29-09-2016-Adequacy-study-flexibility-Belgian-electricity-system

[14] https://antares.rte-france.com/

[15] http://www.meteobelgique.be/article/articles-et-dossiers/53/129-vague-de-froid-definitions-et-introduction.html

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

[17] http://www.elia.be/en/about-elia/newsroom/news/2015/12-03-2015_First-regional-generation-adequacy-assessment-report-published

[18] http://www.ncdc.noaa.gov/

[19] http://www.rte-france.com/sites/default/files/bp2016_complet_vf.pdf

[20] https://www.entsoe.eu/major-projects/the-e-highway2050-project/Pages/default.aspx

[21] http://tyndp.entsoe.eu/

[22] http://economie.fgov.be/nl/binaries/NREAP-BE-v25-NL_tcm325-112992.pdf

[23] http://www.elia.be/en/suppliers/purchasing-categories/energy-purchases/Ancillary-services

[24] http://fes.nationalgrid.com/

[25] http://www.elia.be/en/grid-data/Load-and-Load-Forecasts

[26] https://clients.rte-france.com/lang/an/visiteurs/vie/prod/indisponibilites.jsp

[27] https://transparency.entsoe.eu/

[28] http://www.creg.be/sites/default/files/assets/Publications/Decisions/B1631FR.pdf

[29] http://www.elia.be/en/grid-data/power-generation/generating-facilities

[30] http://www.elia.be/en/grid-data/Load-and-Load-Forecasts

[31] http://www.elia.be/en/grid-data/interconnections/cross-border-flows

[32] http://www.elia.be/en/projects/grid-projects/Interconnector-BeDeLux

[33] http://www.rte-france.com/sites/default/files/bp2017_synthese_17.pdf

[34] https://www.entsoe.eu/data/data-portal/consumption/Pages/default.aspx

[35] https://www.reuters.com/article/us-france-nuclearpower/france-postpones-target-for-cutting-nuclear-share-of-power-production-idUSKBN1D71TM

[36] https://clients.rte-france.com/lang/an/visiteurs/services/actualites.jsp?mode=detail&id=9483

[37] http://www.carbone4.com/download/Carbone4_Energies_Reseau_et_pointe_de_demande.pdf

[38] http://www.sigeif.fr/fichier.php?table=article&champ=Document&id=381&ctrl__=0c0db7d4dbe0cd5a455b923678711517c17b830a&telechargement=oui

[39] https://www.bundesnetzagentur.de/DE/Sachgebiete/ElektrizitaetundGas/Unternehmen_Institutionen/Versorgungssicherheit/Erzeugungskapazitaeten/Kraftwerksliste/kraftwerksliste-node.html

[40] https://www.netzentwicklungsplan.de/de

[41] http://data.netzausbau.de/2030/Szenariorahmen_2030_Genehmigung.pdf

[42] http://www.elia.be/en/projects/grid-projects/alegro/alegro-content

[43] http://www.nemo-link.com/

[44] http://www.cre.fr/reseaux/reseaux-publics-d-electricite/interconnexions#section6

[45] http://www.elia.be/en/products-and-services/cross-border-mechanisms/transmission-capacity-at-borders/flow-based-marktkoppeling-centr-w-europa

[46] http://jao.eu/support/resourcecenter/overview?parameters=%7B%22IsCWEFBMC%22%3A%22True%22%7D

[47] https://www.belpex.be/wp-content/uploads/CWE_FB-MC_feasibility_report.pdf

[48] http://www.tennet.eu/fileadmin/user_upload/Company/Publications/Technical_Publications/Dutch/Rapport_Monitoring_Leveringszekerheid__2015-2031_.pdf

[49] https://www.ecn.nl/publicaties/PdfFetch.aspx?nr=ECN-O--16-035

[50] http://www.ser.nl/~/media/files/internet/publicaties/overige/2010_2019/2013/energieakkoord-duurzame-groei/energieakkoord-duurzame-groei.ashx

[51] http://www.legislation.gov.uk/ukpga/2013/32/pdfs/ukpga_20130032_en.pdf

[52] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/293849/TIIN_6002_7047_carbon_price_floor_and_other_technical_amendments.pdf

[53] https://www.emrdeliverybody.com/Lists/Latest%20News/Attachments/116/Electricity%20Capacity%20Report%202017.pdf

[54] http://www.bmwi.de/DE/Themen/Energie/Konventionelle-Energietraeger/uran-kernenergie,did=156018.html

[55] http://corporate.engie-electrabel.be/fr/actualite/fermeture-definitive-de-la-centrale-tgv-desch-sur-alzette-et-liquidation-de-la-societe-twinerg/

[56] http://www.elia.be/en/about-elia/publications/Public-Consultation/Archives/2017-strategic-reserve-methodology-assumptions-and-data-for-determining-the-volume

[57] http://www.elia.be/en/about-elia/publications/Public-Consultation/Strategic-Reserve-input-data-for-determining-the-volume-for-winter-2018-2019

[58] https://www.energy-charts.de/index.htm

[59] http://transparency.entsoe.eu/

[60] PLEF GAA study 2017. To be published January 2018

[61] http://www.elia.be/~/media/files/Elia/Products-and-services/Strategic-Reserve/20170511_E-Cube_Market%20Response_Report_phase1.pdf

[62] http://www.elia.be/~/media/files/Elia/Products-and-services/Strategic-Reserve/Elia_Market%20Response_Implementation%20report.pdf

[63] https://www.tennet.eu/our-grid/international-connections/cobracable/

[64] https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/EA%2017-18%20Final%20Results.pdf

[65] https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/Transitional%20Auction%2017-18%20Final%20Results%20Report.pdf

[66] http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=8589942578

[67] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/625657/170705_SoS_to_National_Grid.pdf

[68] https://www.kabinetsformatie2017.nl/binaries/kabinetsformatie/documenten/publicaties/2017/10/10/regeerakkoord-vertrouwen-in-de-toekomst/Regeerakkoord+2017-2021.pdf

[69] https://www.rvo.nl/sites/default/files/2015/03/Offshore%20wind%20energy%20in%20the%20Netherlands.pdf

[70] https://www.bundesnetzagentur.de/SharedDocs/Downloads/EN/BNetzA/PressSection/PressReleases/2016/161028_DE_AU.pdf?__blob=publicationFile&v=3

[71] http://www.rte-france.com/sites/default/files/2014_04_09_french_capacity_market.pdf

[72] https://www.entsoe.eu/Documents/Publications/Statistics/Factsheet/entsoe_sfs_2016_web.pdf

[73] https://www.entsoe.eu/Documents/Publications/Statistics/Factsheet/entsoe_sfs2015_web.pdf

[74] https://antares.rte-france.com/wp-content/uploads/2017/11/171024-Rte-Typical-Flow-Based-Days-Selection-1.pdf

[75] https://antares.rte-france.com/wp-content/uploads/2017/11/171024-Rte-Modelling-of-Flow-Based-Domains-in-Antares-for-Adequacy-Studies.pdf

[76] https://www.bundesnetzagentur.de/DE/Sachgebiete/ElektrizitaetundGas/Unternehmen_Institutionen/Versorgungssicherheit/Erzeugungskapazitaeten/Kraftwerksliste/kraftwerksliste-node.html

[77] http://www.elia.be/~/media/files/Elia/About-Elia/Studies/20171114_ELIA_4584_AdequacyScenario.pdf

[78] https://www.entsoe.eu/publications/system-development-reports/outlook-reports/Pages/default.aspx

[79] http://www.elia.be/~/media/files/News/2015-03-05_PLEF_GAA_Report_for_SG2_Final.pdf