Explanatory note for the Public consultation on the scenarios, sensitivities and data for the CRM parameter calculation for the Y-4 Auction with Delivery Period 2027-2028

May 2022

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Introduction

In the framework of the Capacity Remuneration Mechanism ('CRM'), Elia is provided with several tasks described in the Electricity Law[1] and the Royal Decree on the determination of volume and parameters[2].

Elia is requested to establish a CRM calibration report on volume and parameter for the Y-4 auction with Delivery Period 2027-28 and to publish it in November 2022 at the latest. The CRM calibration report is based on the intermediate values and reference scenario selected by the Minister in September 2022.

In order for the Minister to select the data and assumptions which are part of the reference scenario, market parties are invited to be part of a public consultation on the data, scenario and sensitivities for this 3rd CRM calibration report on volume and parameter with Delivery Period 2027-28.

This explanatory document gives stakeholders more context and guidance on the submitted consultation document, which is a vast Excel-file with the above mentioned data. It also foresees some additional qualitative information, which is not quantified in the Excel. Those documents have been established in collaboration with the DG Energy from FPS Economy and in concertation with the CREG, as stated in the Royal Decree.

This explanatory note consists in 4 main sections:
- The legal and regulatory framework (§1)
- The scenario and sensitivities (§2)
- The other parameters which have to consulted (§3)
- The summary of the questions to stakeholders (§4)

Should there be any remark or additional suggestion on this document, this can obviously be provided as part of the consultation contribution. In the framework of this 3rd CRM auction and regarding the high level of uncertainties abroad, Elia mentions explicitly specific questions to stakeholders on which inputs would be greatly appreciated. Those questions are integrated in the document and summarized on §4 of this document. Stakeholders are also invited to comment sensitivities and/or propose additional sensitivities or elements to be included to the reference scenario.

Note that the slide deck presented during the task force of the 6th May 2022[3] can also be considered as reference for the public consultation.

[1] https://www.ejustice.just.fgov.be/eli/loi/1999/04/29/1999011160/justel
[2] http://www.ejustice.just.fgov.be/eli/arrete/2021/04/28/2021041351/justel
[3] https://www.elia.be/en/users-group/adequacy-working-group/20220506-meeting

1 Legal and regulatory framework

This public consultation takes place according to the Royal Decree on volume and parameters[4].

Article 3 presents the objective of the public consultation in the framework of the reference scenario selection process.

Royal Decree Reference	
Art. 3. § 1er. Le gestionnaire de réseau effectue, en collaboration avec la Direction générale de l'Energie et en concertation avec la commission, une sélection d'un ou de plusieurs scénarios et sensibilités selon les étapes décrites à l'article 4, §§ 2 à 4 inclus. § 2. A partir de l'évaluation européenne, visée à l'article 23 du Règlement (UE) 2019/943, et / ou de l'évaluation nationale visée à l'article 24 du Règlement (UE) 2019/943, les plus récemment disponibles au moment de la sélection, un ou plusieurs scénarios et sensibilités sont sélectionnés. Cette sélection comprend au moins le scénario de référence central européen visé à l'article 23, 1er alinéa, 5, b) du Règlement (UE) 2019/943. Tant que lesdites évaluations ne sont pas encore disponibles, une sélection est effectuée à partir d'autres études disponibles. § 3. Les données et hypothèses à partir desquelles lesdits scénarios et sensibilités ont été établis, sont mises à jour sur la base des informations pertinentes les plus récentes. § 4. En outre, d'autres sensibilités qui peuvent avoir un impact sur la sécurité d'approvisionnement de la Belgique, peuvent être définies, y inclus des	**Art. 3.** § 1. De netbeheerder maakt, in samenwerking met de Algemene Directie Energie en in overleg met de commissie, een selectie van één of meerdere scenario's en gevoeligheden volgens de stappen beschreven in artikel 4, §§ 2 tot en met 4. § 2. Uit de op het ogenblik van de selectie meest recent beschikbare Europese beoordeling bedoeld in artikel 23 van Verordening (EU) 2019/943 en/of de nationale beoordeling bedoeld in artikel 24 van Verordening (EU) 2019/943, worden één of meerdere scenario's en gevoeligheden geselecteerd. Deze selectie omvat minstens het Europese centrale referentiescenario bedoeld in artikel 23, lid 1, 5, b) van Verordening (EU) 2019/943. Tot zolang deze beoordelingen nog niet beschikbaar zijn, wordt een selectie gemaakt uit andere beschikbare studies. § 3. De gegevens en hypothesen waaruit deze scenario's en gevoeligheden zijn opgebouwd worden geactualiseerd op basis van de meest recente relevante informatie. § 4. Daarnaast kunnen andere gevoeligheden gedefinieerd worden die een impact kunnen hebben op de bevoorradingszekerheid in België, met

[4] http://www.ejustice.just.fgov.be/eli/arrete/2021/04/28/2021041351/justel

évènements en dehors de la zone de réglage belge. § 5. Les scénarios et sensibilités sélectionnés, en ce compris les données et hypothèses à partir desquelles ils ont été établis, sont soumis à une consultation publique telle que visée à l'article 5. § 6. Sur la base du rapport de consultation, et en particulier des informations ayant trait à l'article 5, § 2, 1° et 2°, la commission rédige une proposition pour le Ministre de l'ensemble des données et hypothèses à retenir, qui constituent ensemble une proposition de scénario de référence. La Direction générale de l'Energie formule un avis sur cette proposition. § 7. Compte tenu de la proposition de la commission, des recommandations du gestionnaire du réseau et de l'avis de la Direction générale de l'Energie, le Ministre décide, par arrêté délibéré en Conseil des ministres depuis la décision prise en 2021, au plus tard le 15 septembre de l'année précédant les enchères, de l'ensemble des données et des hypothèses qui doit être sélectionné comme scénario de référence. Le Ministre peut déroger à la proposition de la commission moyennant motivation adéquate.	inbegrip van gebeurtenissen buiten de Belgische regelzone. § 5. De geselecteerde scenario's en gevoeligheden, inclusief de gegevens en hypothesen waaruit ze zijn opgebouwd, worden onderworpen aan een openbare raadpleging bedoeld in artikel 5. § 6. Op basis van het consultatierapport en in het bijzonder de informatie die betrekking heeft op artikel 5, § 2, 1° en 2° maakt de commissie een voorstel op voor de Minister van de te weerhouden set van gegevens en hypotheses, die samen een voorstel van referentiescenario vormen. De Algemene Directie Energie formuleert een advies op dit voorstel. § 7. Rekening houdend met het voorstel van de commissie, de aanbevelingen van de netbeheerder en het advies van de Algemene Directie Energie, beslist de Minister, bij besluit vastgesteld na overleg in ministerraad vanaf de beslissing genomen in 2021, ten laatste op 15 september van het jaar voorafgaand aan de veiling welke set van gegevens en hypotheses moet worden geselecteerd als het referentiescenario. De Minister kan hierbij afwijken van het voorstel van de commissie mits passende motivatie

Article 5 sets the requirements of the public consultation and the data that need to be submitted to public consultation.

Royal Decree Reference	
Art. 5. § 1er. Le gestionnaire de réseau organise une ou plusieurs consultations publiques conformément à l'article 7undecies, § 3, alinéa 3, de la loi du 29 avril 1999 durant une période de minimum un mois. Le gestionnaire du réseau informe les acteurs de marché de la tenue de cette (ces) consultation(s). § 2. Au moins les sujets suivants sont soumis à une consultation publique : 1° la mise à jour des données et des hypothèses du scénario ou des scénarios, ainsi que des sensibilités, telles que visées à l'article 3, § 3 ; 2° la pertinence des sensibilités visées à l'article 3, §4, en ce compris les données et hypothèses à partir desquelles elles ont été établies ; 3° le type de capacité supplémentaire visé à l'article 6, § 1er ; 4° les sources publiques des scénarios pour les années postérieures à l'année de livraison à partir desquelles les données d'entrée sont utilisées pour le calcul des rentes inframarginales annuelles visées à l'article 10, §6 ; 5° la liste réduite des technologies existantes qui seront raisonnablement disponibles et qui sont éligibles pour la détermination du prix maximal intermédiaire visé à l'article 18, §1er.	**Art. 5.** § 1. De netbeheerder organiseert een of meerdere openbare raadpleging(en) met het oog op de opmaak van zijn verslag en zijn voorstel bedoeld in artikel 7undecies, § 3, derde lid van de wet van 29 april 1999, gedurende een periode van ten minste één maand. De netbeheerder informeert de marktdeelnemers over het houden van deze raadpleging(en). § 2. De volgende onderwerpen worden ten minste aan openbare raadpleging onderworpen: 1° de actualisatie van de gegevens en hypothesen van het scenario of de scenario's en de gevoeligheden zoals bedoeld in artikel 3, § 3; 2° de relevantie van de gevoeligheden bedoeld in artikel 3, § 4, inclusief de gegevens en hypothesen waaruit ze zijn opgebouwd; 3° het type bijkomende capaciteit bedoeld in artikel 6, § 1; 4° de publieke bronnen van de scenario's voor de jaren na het leveringsjaar waaruit de invoergegevens gebruikt worden voor de berekening van de jaarlijkse inframarginale inkomsten, bedoeld in artikel 10, § 6; 5° de beperkte lijst van bestaande technologieën die redelijkerwijs beschikbaar zullen zijn, en die in aanmerking komen voor de bepaling van de intermediaire maximumprijs, bedoeld in artikel 18, §1.

2 Scenario and sensitivities

This chapter describes the data and assumptions related to the scenarios and sensitivities that have to be submitted to public consultation according to article 5 of the Royal Decree. The overall process should lead to the Minister to select a reference scenario that will be used as basis for the CRM calibration report with Delivery Period 2027-28.

This chapter contains two main parts: the main data and assumptions regarding the scenario (Article 5, §2, 1°) on §2.1 and the sensitivities that could be integrated in the reference scenario (Article 5, §2, 2°) on §2.2.

Note that when a sensitivity is proposed regarding one of the data and assumptions presented in §2.1, a black box with the reference to the associated sensitivity is added.

2.1 Data and assumptions for the scenario

This section presents all the data and assumptions included in the scenario. The European Resource Adequacy Assessment 2021 (ERAA 2021)[5] is taken as reference for the Y-4 auction with Delivery Period 2027-28, as it is the latest published European Resource Adequacy Assessment by ENTSO-E.

The data for Belgium is based on the Adequacy and Flexibility study 2022-32 published in June 2021[6] and is updated according to the most recent available information. The sources of the updates are mentioned in each sub-section (§2.1.1. to §2.1.3).

Regarding the flow-based parameters (see § 2.1.4), Elia proposes to keep the same model and assumptions as implemented in the Adequacy and Flexibility study 2022-32.

The data for all other countries is based on ERAA 2021 and is updated based on the most recent national/regional adequacy studies and known ambitions, as described in §2.1.5.

The methodology applied will take into account the latest European methodologies approved in 2020, as applied in the Adequacy and Flexibility study 2022-32 published in June 2021. In particular, the study will apply the 200 synthetic years from the forward-looking climate database developed by Méteo France (see §2.1.6).

Finally, the economic parameters proposal presented in §2.1.7 are based on latest available information and aim to integrate the uncertainties due to the current geopolitical context.

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[5] https://www.entsoe.eu/outlooks/eraa/
[6] https://www.elia.be/fr/marche-de-electricite-et-reseau/adequation/etudes-adequation

2.1.1 Generation & Storage

First, the Belgian generation and storage capacities are presented. This sub-section also includes the forced outage rates based on historical data. The data is in line with the data used in the Adequacy and Flexibility study (2021), in line with article 3, §2 of the Royal Decree, and have been updated according to the most recent available information sources. Figure 1 presents graphically the main updates implemented for the Y-4 auction with Delivery Period 2027-28 compared to the previous Y-4 auction targeting the Delivery Period 2026-27.

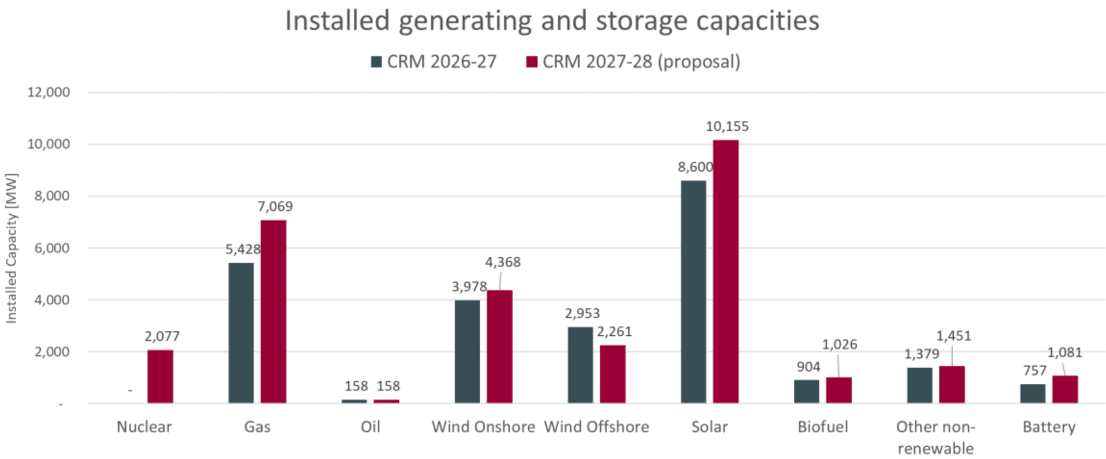

Figure 1: Installed capacity available to the market on Belgian market zone

2.1.1.1 Generation & Storage summary

A summary of the generation and storage installed capacities for the 2027-28 Delivery Period is presented in the Excel file (section 1.1). Table 1 presents the installed capacities for each technology (including demand-side response data presented in §2.1.2.2), compares it with the values from previous Y-4 auction targeting Delivery Period 2026-27 and provides a global explanations on the updates.

Note that additional capacity could be added to the reference scenario based on the pre-selected capacity types to make the reference scenario selected by the Minister adequate for Belgium (see section 3.1), as mentioned in article 5 §1.

Net Capacities in MW	CRM calibration 26-27	CRM calibration 27-28	Explanation of the updates
Nuclear	0	2077	10y lifetime extension of Tihange 3 & Doel 4
Gas	5428	7069	Removal of old Seraing ST (-170 MW) + Addition of new CCGT in Seraing (+ 885 MW) and Les Awirs (+ 890 MW) + Capacity increase for St Ghislain (+36 MW)
Oil	158	158	No evolution foreseen
Hydro - Run of River	140	143	Target one year later, based on NECP WAM scenario, as mentioned in AdFlex 21
Wind Onshore	3978	4368	Updated to consider latest ambitions
Wind Offshore	2953	2261	First phase of MOG2 (-700 MW) expected for Q1-Q2 2028 and update of the installed capacity (+8 MW)
Solar	8600	10155	Updated to consider latest developments and ambitions
Biofuel (including waste)	904	1026	Increase based on the trend observed for profiled technology on Elia's internal database
Others non-renewable generation	1379	1451	Increase based on the trend observed on Elia's internal database
Batteries	757	1081	Updated to consider latest developments
Pumped Storage	1224	1305	Reservoir extension of Coo 1-3

Table 1: Update on generation & storage data

2.1.1.2 Individually modelled thermal generation

Section 1.2 of the Excel file details all individually modelled thermal generation facilities available for the 2027-28 Delivery Period. The Excel document describes for each unit, its name, owner, technology, derating factor category, used fuel and the associated net generation capacity.

This list integrates the nuclear power plants of Tihange 3 and Doel 4, following the decision of the authorities to extend the lifetime of the 2 latest units. In the framework of the Y-4 auction with Delivery Period 2027-28, it is assumed that the 2 facilities will be available during the whole delivery period..

This list also integrates the two CCGT contracted for 15 years in the framework of the Y-4 auction for Delivery Period 2025-26[7], including the results of the CRM re-run[8].

Note that a sensitivity is foreseen on Belgium's thermal units (TJ / OCGT) due to the possible introduction of a CO2 threshold (see §2.2.3).

2.1.1.3 Storage

The storage installed capacity and reservoir volume for 2027-28 Delivery Period is presented in the Excel (section 1.3).

Pumped-storage

The turbining capacity of Coo for Delivery Period 2027-28 takes into account the reservoir extension of Coo 1-3[9] bringing the overall pumped-storage (Coo and Plate Taille) installed capacity to 1305 MW and a storage reservoir capacity of 5650 MWh available for economical dispatch (considering that 500 MWh are dedicated to black-start services).

Batteries

3 categories of batteries are considered, as presented in the Adequacy and Flexibility study 2022-32: large-scale batteries, small-scale batteries and V2G. The updates in terms of installed capacity is presented in Figure 2.

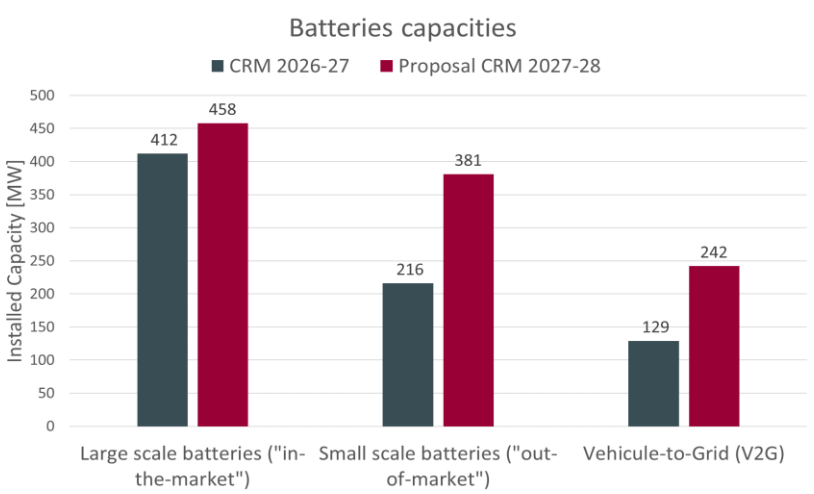

Figure 2: Evolution of the installed capacity for batteries

[7] https://www.elia.be/fr/donnees-de-reseau/adequation/resultats-de-l-enchere-crm
[8] https://www.elia.be/fr/actualites/communiques-de-presse/2022/04/20220414_rerun-crm
[9] https://corporate.engie.be/fr/energy/hydraulique/centrale-daccumulation-par-pompage-de-coo/le-projet-dextension

Large-scale batteries estimation is based on the Adequacy and Flexibility study 2022-32 published in June 2021, for which the trajectory takes into account the target fixed in the Energy Pact. For large-scale batteries a significant update concerns the energy content associated to this technology. Indeed, based on information available on existing and known projects, a 70%/30% split is performed between large-scale batteries projects with respectively a 4h storage capacity and a 2h storage capacity. In the framework of the Y-4 auction for Delivery Period 2026-27, a single energy content of 2h was considered.

Regarding small-scale batteries, the trajectory from the Adequacy and Flexibility study 2022-32 is increased in order to take into account the higher amount of installed residential batteries in Flanders due to subsidies. On the short-term, a higher rate of installation is foreseen. Then, the assumption from the Adequacy and Flexibility study 2022-32 is maintained, meaning that each year 0.5% of the PV installations add a battery capacity of the size of the PV installation (with 3 hours of storage).

V2G are electric vehicles (EV) that allow bi-directional (dis)charging when connected to a bi-directional charger. In order to estimate the amount of V2G capacity (the battery capacity that would be connected permanently to the grid and that would allow bi-directional charging), we assumed that:

- a certain amount of new EV registrations are capable of bi-directional (dis)charge and are connected permanently to a bi-directional charger. We assume this to be 2% of new EV registrations in 2022 to 10% in 2030;
- in order to calculate the amount of storage (MWh) and capacity (kW), a charger of 7kW and 4 hours storage was assumed;
- due to the higher amount of EVproposed to be taken into account in this scenarios (linked to the increased ambitions with regards to electrification of transport), the installed capacity of V2G for Delivery Period 2027-28 increases compared to the value set in the Adequacy and Flexibility study 2022-32.

From this volume and capacity of storage, it was assumed that in 2021, 1% of the V2G amount is reacting to electricity prices. The other 99% is considered as 'out-of-market' (and is therefore taken into account in the consumption profile following the ERAA methodology). The percentage of 'in-the-market' is assumed to evolve to up to 50% in 2030. The value of 33% taken for 2027 is a linear interpolation between these values.

2.1.1.4 Renewable and profiled non-renewable

Section 1.4 of the Excel file details the renewable energy and profiled thermal production.

Regarding onshore wind, the installed capacity integrates the latest national ambitions. Compared to the value from previous Y-4 auction, the increase is explained by the fact that the Delivery Period is one year later and that the ambitions are slightly increased for onshore wind.

Regarding offshore wind, the generation capacity is set to 2261 MW. This value is based on the latest information regarding installed capacity and to the fact that the first phase of MOG II is expected for Q1-Q2 2028 according to latest public information[10], meaning that the commissioning date was delayed compared to the information available in the framework of the previous auction where an increase of the offshore capacity was taken into account.

Regarding photovoltaics, the trajectory presented in the Adequacy and Flexibility study 2022-32 is updated based on the latest information available, among others the increased installation rate observed in Wallonia, the impact of lower VAT decided by the Federal government for installations in new buildings (or building younger than 10 years) and the geopolitical context leading to high electricity prices (which make such installations more profitable). An installed capacity of 10155 MW for Delivery Period 2027-28 is then considered.

The assumptions for onshore wind, offshore wind and photovoltaics solar are presented in Figure 3, and compared to the values of the previous auction

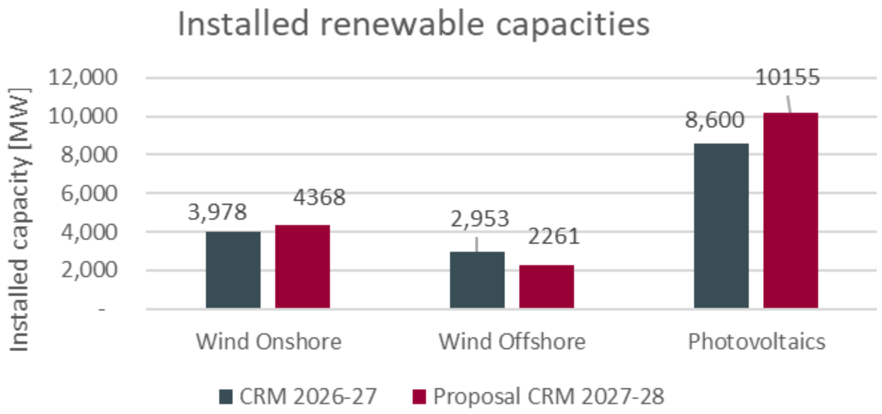

Figure 3: Overview of RES capacity installed capacity

#Q1 – RES generation

Do you agree with the proposed updates for solar, wind onshore and wind offshore based on the latest available information? If not, do you have additional information or know of developments that should be taken into account according to you?

[10] https://economie.fgov.be/fr/themes/energie/sources-denergie/energies-renouvelables/exploitation-en-mer-du-nord/energie-eolienne-belge

The profiled thermal without daily schedule units (gas CHP, biomass and waste) installed capacity is based on the latest information from Elia's internal database which gathers the latest information from the DSOs. The information on the different existing projects and projects assumed to be developed in the next years leads to an increase for all types of profiled units as presented in Figure 4.

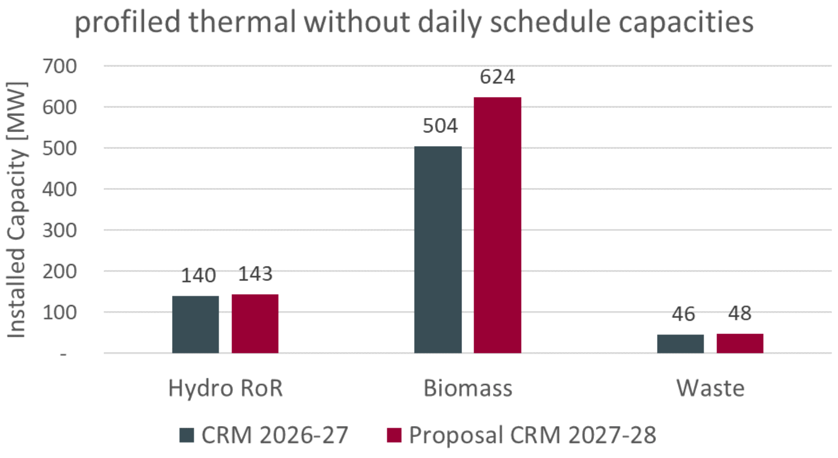

Figure 4: profiled thermal without daily schedule units (gas CHP, biomass and waste) installed capacity

2.1.1.5 Forced outage rates

The forced outage (FO) rates are presented in the Excel (section 1.5) and are based on the methodology set in the Royal Decree and is in line with the methodology used in other adequacy studies performed by Elia.

For generation technologies, these numbers have been calculated using availability data of the last 10 years (from 2012 up to and including 2021). The data is taken from the ENTSO-E transparency platform[11] (ETP) where available and combined with Elia's internal database where needed. The forced outage rates of all technologies, except nuclear and HVDC links, is calculated as:

$$Average\ FO\ rate = \frac{FO\ energy\ 2012 \rightarrow 2021}{FO\ energy\ 2012 \rightarrow 2021 + Available\ energy\ 2012 \rightarrow 2021}$$

Regarding the forced outage rate of HVDC links, a 6% value is proposed, as used in studies performed by ENTSO-E. Regarding the HVDC FO rate, this value is in line with the preceding calibration volume reports.

[11] https://transparency.entsoe.eu/

For the forced outage rate of nuclear generation units, a similar approach is proposed by Elia and is further detailed in “Appendix: Elements to determine for the availability of the Belgian nuclear units”. For this parameter, Elia calculates values for different categories: ‘Technical’ Forced Outages, ‘Long-lasting’ Forced Outages and Planned Outages during winter periods. Those are presented in Table 2.

'Technical' forced outage rate over 2012-2021	'Long-lasing' forced outage rate over 2012-2021	Planned outage rate during winter periods over 2012-2021
4.0%	16.5%	8.1%

Table 2: Parameters proposed for the determination of the types of unavailability for nuclear

#Q2 – Nuclear forced outage rate

Do you agree with this methodology and do you have comments on the relevant parameters to be taken into account?

2.1.2 Consumption & Demand-side response

The following sub-section is dedicated to the load. This includes demand and demand-side response parameters. The data is based on the values published in the Adequacy and Flexibility study 2022-32. Table 3 presents the main updates implemented in the CRM calibration.

Data	CRM calibration 2026-27	CRM calibration 2027-28	Sources
Electricity total consumption	91.5 TWh	94.6 TWh	Economic projections from Federal Planning Bureau (June 2021) complemented with additional electrification of heat and transport following national ambitions and ‘FitFor55’/’RePowerEU’ proposed plans
Electricity peak consumption	14.6 GW	15.3 GW	Peak demand without taking into account additional flexibility (increased share of V1G, higher level of out-of-market batteries), which will level out the peak load.
Demand-side response shedding	2044 MW	2226 MW	1 year later (based on Energy Pact) + increase based on potential associated to additional electrification added to the consumption
Demand-Side response shifting	700 MWh/day	1000 MWh/day	1 year later (based on Energy Pact) + increase based on potential associated to additional electrification added to the consumption

Table 3: Update on consumption data

2.1.2.1 Total electricity consumption

The total electricity demand was forecasted using the Total Demand forecasting tool 'BECalc tool' developed in collaboration with Climact for the FPS Environment which was improved in order to take into account factors such as short-term economic projections and growing electrification to quantify total electricity demand projections over the short- and medium-term. The methodology is explored in detail in a public report[12] and was discussed and consulted upon with stakeholders[13]. The latest projections were presented in September 2021 based on latest projections from the Federal Planning Bureau from June 2021[14]. The tool takes a set of input parameters which represent the main variables driving the evolution of the total electricity demand per sector and for Belgium. The following parameters were used: macro-economic indicators, energy efficiency, additional electrification from electric vehicles and heat-pumps and thermo-sensitivity. The evolution of DSO and TSO grid losses were also included in the forecasting process.

The tool uses as principal source the final NECP (WAM scenario for the 2027-28 horizon) concerning the electrification indicators, being the amount of heat-pumps and electric vehicles (see Table 4) updated to reflect the national ambitions with regards the heat and transport electrification (measures with regards the company cars, low emission zones, ban of new ICE cars in Flanders, new Legislation of the Flemish government regarding the installation of heat pumps…). Those were also complemented with recent plans and measures being discussed at European level such as the 'FitFor55' package and the 'RePowerEU' plan.

The impact of macro-economic trends on the total electricity demand is taken into account by considering the latest available projections of the Federal Planning Bureau from June 2021.

The yearly demand proposal for Delivery Period 2027-28 is then derived from the estimation of Climact complemented with the latest forecast regarding heat-pumps and electric vehicles.

In any case, it is proposed to update the demand based on new economic projections of the Federal Planning Bureau, expected to be published in June 2022. As done for previous auctions, this value will be handed over to the competent authorities when available.

[12] https://www.elia.be/en/users-group/plenary-meetings/20210928-meeting
[13] https://www.elia.be/en/public-consultation/20200603_public-consultation-on-the-methodology-of-volumes-of-strategic-reserve-for-winter-2021-2022
[14] https://www.elia.be/en/users-group/plenary-meetings/20210928-meeting

	CRM 2026-27	Proposal CRM 2027-28
Electric Vehicles	500 000	850 000[15,16]
Heat Pumps	115 000	250 000[17]

Table 4: Assumptions regarding heat pumps and electric vehicles

Regarding the 'optimized charging' (**V1G**) of electric vehicles that is added to the hourly total electricity consumption, it is proposed to consider the same methodology as performed in in the Adequacy and Flexibility study 2022-32 (Figure 3-8) but to assume a faster evolution of the share between daily natural and optimized charging profile. In that sense, it is proposed to consider a share of V1G of **41%**, corresponding to the value set for 2029 in in the Adequacy and Flexibility study 2022-32.

#Q3 – Demand, including number of Electric Vehicles and Heat Pumps

Do you agree with the values provided for EV and HP? Would you propose another value (increasing or decreasing), why and based on which source?

Do you agree with the proposed total demand? Would you propose another value, why and based on which source?

Given the current situation with high electricity prices which could impact the total demand for electricity, it is proposed to assess this effect and include it when providing the updated forecast for the electricity demand. Given the uncertainty regarding energy prices, this is proposed to be incorporated in a specific sensitivity (see §2.2.5). If stakeholders are aware of studies that quantify such effect, we are happy to get those in their answer to this public consultation.

[15] FEBIAC ZERO bis scenario, including VLA announcements on phase-out of ICE, link: https://www.frdo-cfdd.be/sites/default/files/content/4_laurent_willaert.pdf

[16] Interpolation towards Plan Bureau forecast for 2030 (1,8M of electric vehicles) also gives a figure around 850k EV in 2027. Link: https://www.plan.be/databases/data-41-nl-vooruitzichten_van_de_transportvraag_editie_2022_statistische_bijlage

[17] REPowerEU package plans to install minimum 30M new heat pumps towards 2030, which was then divided over the member states.

2.1.2.2 Peak electricity consumption

The peak electricity consumption is calculated using consumption profiles generated based on the total electricity consumption and climate years as further detailed in §2.1.6. The increase in peak consumption is related to the increase in total electricity consumption but further accentuated by the rise in heat-pump and electric vehicle assumptions (Table 4).

This peak load should be considered as a rough estimate as it does not take into account latest projections from Climact based on most recent economic projections of the Federal Planning Bureau, expected to be published in June 2022, and the additional flexibility means integrated in the scenario dataset (as mentioned in Table 3). Indeed, a higher share of V1G (optimized charging of electric vehicles) is foreseen (see §2.1.2.1) as well as a higher number of out-of-market batteries, due to increased number of electric vehicles (V2G) and the higher number of residential batteries (see §2.1.1.3), which would level out the peak consumption.

2.1.2.3 Demand-Side Response

Section 2.2 of the Excel file presents the data associated to demand-side response in Belgium. These numbers are based on the Belgian Energy Pact and integrate the latest E-cube study used as basis in the latest Adequacy and Flexibility study. The numbers are extrapolated until 2023 with a 7% growth rate then an interpolation is applied to the 2030 value based on the Energy Pact and upscaled to take into account the higher electrification assumptions.

Demand-side response shedding is subdivided in 5 categories depending on availability (1h, 2h, 4h, 8h or no limit), in line with the Adequacy and Flexibility study 2022-32. A volume is associated for each category. The total volume of demand-side response shedding is equal to 2226 MW for the 2027-28 Delivery Period. It includes both volume dedicated to the energy market and to the ancillary services.

Moreover, a demand shifting category is implemented as in the previous CRM calibration, the difference with demand-side shedding is that in this case, electricity is consumed during another moment of the day. This amounts to 1000 MWh/day based on the Energy Pact and upscaled to take into account to take into account the higher electrification assumptions.

#Q4 – Impact of recent measures on consumption and DSR

How would you quantify the impact that the latest European plans (Fit For 55, REPowerEU) and national ambitions could have on the consumption and demand-side response volumes?

2.1.3 Balancing need

This subsection is dedicated to the required balancing need, i.e. reserve capacity, that needs to be provided to deal with unexpected variations in demand and generation. The reserve capacity applied for the Y-4 auction of 2027-28 Delivery Period is presented in the Excel file (section 3).

The balancing need impacts the volume to be procured in each CRM auction. This estimation is required by article 11, §2, 2° of the Royal Decree. The balancing need is added to the average load during simulated scarcity hours. This volume includes the capacity assumed to be procured by Belgian generation and storage units and by the Belgian demand (see §2.1.2.2), as well as the volumes of cross-border reserve capacity, in order to make sure that full reserve capacity needs can be delivered, also during scarcity periods.

The necessary total balancing need is defined as the sum of the FCR[18] reserve capacity and the total FRR[19] reserve capacity for the Delivery Period 2027-28.

- The FCR capacity is expected to remain constant at 75 MW during the 2027-28 Delivery Period. Currently, the capacity is determined based on the share of generation and demand of Elia's LFC[20] block compared to the total generation and demand in the synchronous zone of Continental Europe. This projection is therefore conducted based on the Belgian and European generation and demand profiles resulting from the Adequacy and Flexibility 2022 simulations.

- The upward FRR capacity (aFRR + mFRR) is expected to increase towards 1175 MW in 2027-28, as presented in the Adequacy and Flexibility study 2022-32. Currently, the capacity is determined on a day-ahead basis by means of Elia's dynamic dimensioning method taking into account prediction error risks and forced outage risks. Future reserve capacity needs therefore depend on system evolutions and performance of the market.

Based on the above-mentioned assumptions, the balancing need volume for 2027-28 Delivery Period is therefore assumed to be equal to 1250 MW.

Regarding the adequacy simulations conducted with Elia's simulation model, the balancing need to be accounted for can be split into two categories, the reserve capacity provided by Belgian demand-side response and the other capacity. An estimation based on Elia's projections assumes a total of 483 MW of balancing capacity to be provided by demand-side response in 2027-28. This capacity can be deducted from the total Belgian demand-side response.

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18 FCR: Frequency Containment Reserves
19 FRR: Frequency Restoration Reserves
20 LFC: Load Frequency Control

2.1.4 Cross-border market capacities

The CRM calibration will use an up-to-date flow-based modelling as used in the Adequacy and Flexibility study 2022-32. The parameters of this model are presented in the Excel file (section 4). More details on the modelling can be found in Appendix: Details on cross-border market capacities.

The presented domain will be complemented with the NTC values taken from the European Resource Adequacy Assessment 2021 (ERAA21) of ENTSO-E for the borders which are not included in the flow-based region.

Note that a sensitivity is foreseen to reflect possible smaller cross-border capacities due to the non/strict achievement of the FB CEP rules for 2027 or less optimistic assumptions regarding grid availability during winter(see §2.2.2).

Figure 5 provides an overview of the main parameters required to generate the flow-based domains on different targets years. For this study, in line with the foreseen market operations, Core is modelled as a flow-based region. Flows outside Core are subject to NTC constraints, and the interaction between the flow-based region and flows over external borders to countries beyond Core are modelled using advanced hybrid coupling (AHC). For the 2027-28 Delivery Period no external constraint is considered and only cross-border CNECs will be considered using the grid model from the TYNDP 2020.

When creating flow-based domains for this study, the assumption is taken that no grid maintenance is planned throughout Europe in the winter period. In other words, while the impact of single contingencies is taken into account through the CNEC definition process, it is assumed that prior to a contingency, the European transmission grid is always fully available and operational. While for winter months, with a focus on the representation of scarcity events, this optimistic assumption is retained; for summer months assuming the absence of any grid maintenance is deemed unrealistic. As a proxy for this reduced availability of the transmission grids, the domains generated for the summer months assume a fixed RAM of 70% applied to the fully available transmission grid.

The flow-based domain creation process will be described in the next section. Part of this process has the objective of determining initial loadings on all branches monitored in the flow-based market coupling. This approach assumes a decent approximation of the actual general market tendencies when determining such initial flows. In order to mitigate inaccuracies linked to flow reversals resulting from large approximation errors, the final RAMs will be capped to the technical transmission capacity of each CNEC.

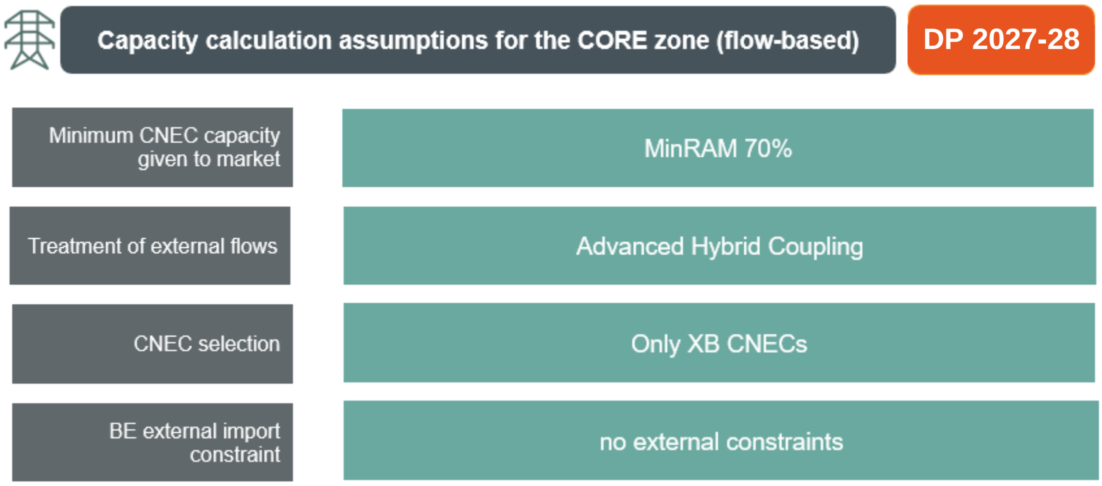

Figure 5: Overview of assumptions for the Core flow based domain creation

2.1.5 Other countries data

The same data as presented from §2.1.1 to §2.1.3 are also necessary for other countries. In the framework of the CRM calibration, the same perimeter as used for the Adequacy and Flexibility study 2022-32 will be taken into account and is represented on Figure 6. It includes **twenty-eight countries**.

- Austria (AT)
- Belgium (BE)
- Bulgaria (BG)
- Switzerland (CH)
- the Czech Republic (CZ)
- Germany (DE)
- Denmark (DK)
- Estonia (EE)
- Spain (ES)
- Finland (FI)
- France (FR)
- United Kingdom (GB and NI)
- Greece (GR)
- Croatia (HR)
- Hungary (HU)
- the Republic of Ireland (IE)
- Italy (IT)
- Lithuania (LT)
- Luxembourg (LU)
- Latvia (LV)
- the Netherlands (NL)
- Norway (NO)
- Poland (PL)
- Portugal (PT)
- Romania (RO)
- Sweden (SE)
- Slovenia (SI)
- Slovakia (SK)

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

Figure 6: EU simulation area

The most recent European dataset available is the ERAA 21 data. Unfortunately only the 2025 and 2030 time horizons were made publicly available by ENTSO-E as they were the only 2 for which the input data was quality-checked and simulations were performed.

In the CRM calibration for the 2027-28 Delivery Period, the ERAA21 dataset is used as an initial dataset but updated with the latest public information available for neighboring countries. The updates made compared to the ERAA21 data can be consulted in the Excel file (section 5).

2.1.5.1 Overview of the updates for neighboring countries

Table 5 presents the main updates proposed compared to ERAA21 data, taking into account updates for the total yearly consumption as well as some technologies, including coal/lignite, wind onshore, wind offshore and solar. For those categories, significant updates are considered based on information derived from recent national studies and ambitions. If no value is mentioned, it is assumed that the value will be directly derived from ERAA21 data. It is important to note that the data for the ERAA21 was only published for 2025 and 2030 by ENTSO-E and that therefore a linear interpolation was used to calculate values for 2027.

Countries	Proposed Updates				
	Lignite/Coal [MW]	Wind Onshore [MW]	Wind Offshore [MW]	Solar [MW]	Demand [TWh/y]
DE	10,700	74,300	22,000	137,200	623
FR	0	24,100	6,200	44,000	482
NL	2,670	7,800	11,500	26,900	143
GB	0	24,200	36,300	31,900	306

Table 5: Updates for neighboring countries based on latest available information

Regarding Germany, the proposed coal phase-out in 2030 is taken into account. In order to establish a value for Delivery Year 2027-28, an interpolation is performed with the installed capacity mentioned in ERAA21 for 2025, leading to a proposed installed capacity of 10,700 MW. Wind onshore, wind offshore and solar are derived from the latest announcement from the “Easter package”[21], which sets targets for Germany for 2030. The electricity consumption is based on an interpolation between the ERAA21 value for 2025 and the value from the coalition agreement[22] and in line with the NEP 2021 - scen B from the German Grid Development Plan[23].

Regarding France, 2 main sources are considered: the latest announcement from Macron regarding energy in France[24] and the “Bilan Prévisionnel”[25] published in 2021. For wind onshore, the same ERAA21 value for 2025 is kept constant towards Delivery Period 2027-28, considering that no major development in onshore wind is foreseen, following Macron’s announcement. Solar and wind offshore values are proposed respectively based on Figures 3.5 and 3.8 of the “Bilan Prévisionnel”, in line with the

[21] https://www.bmwk.de/Redaktion/DE/Downloads/Energie/0406_ueberblickspapier_osterpaket.pdf?__blob=publicationFile&v=14

[22] https://www.spd.de/fileadmin/Dokumente/Koalitionsvertrag/Koalitionsvertrag_2021-2025.pdf

[23] https://www.netzentwicklungsplan.de/de

[24] https://www.vie-publique.fr/discours/283773-emmanuel-macron-10022022-politique-de-lenergie

[25] https://assets.rte-france.com/prod/public/2021-05/Bilan%20previsionnel%202021%20-%20annexes%20techniques.pdf

objectives of the “Programmation pluriannuelle de l’énergie” (PPE). The electricity consumption is also based on the “Bilan Prévisionnel”, considering the scenario “Atteinte des objectifs PPE/SNBC”.

Note that different sensitivities are foreseen on French nuclear availability (see §2.2.1).

Regarding the Netherlands, the updated values are based on the scenario IPKA0 from the “Monitoring leveringszekerheid”, published by Tennet in 2021[26] and the latest announcement from the Dutch government[27]. The scenario selected is based on the recent “Investeringsplan 2022-2031 Net op land (IP2022)” with a higher electricity demand and more sustainable generation. Moreover, this scenario is in line with the Dutch Climate Akkoord. The values for electricity consumption, onshore wind and solar are directly derived from this scenario while the value for offshore wind also consider the latest national announcement to reach 21GW of offshore wind in 2030. As, most of this 21GW capacity won’t be available before 2030, it is proposed to select the initial value for 2030 from the “Monitoring leveringszekerheid” as value for the Delivery Period 2027-28.

Finally, regarding Great Britain, the latest announcements have also been considered. First, it is considered that Great Britain will no longer use coal to generate electricity from 1st October 2024[28]. Then, the UK Minister of Energy has proposed doubling onshore wind capacity to 30GW by 2030[29] and triple solar capacity to 50GW[30]. Regarding offshore wind and electricity consumption, it is proposed to consider the value from the “Leading the Way” scenario of the “Future Energy Scenario (FES)” published in 2021[31].

[26] https://www.tennet.eu/fileadmin/user_upload/Company/Publications/Technical_Publications/Dutch/TenneT_Rapport_Monitoring_Leveringszekerheid_2021.pdf
[27] https://windpowernl.com/2022/03/20/dutch-government-to-double-offshore-wind-capacity-to-21-gw-in-2030/
[28] https://www.gov.uk/government/news/end-to-coal-power-brought-forward-to-october-2024#:~:text=From%201%20October%202024%20Great,(Wednesday%2030%20June%202021).
[29] https://www.reutersevents.com/renewables/wind/uk-energy-minister-aims-double-onshore-wind-portugal-leaps-large-floating-arrays
[30] https://www.ft.com/content/60a90c04-f7ea-4a20-ba07-00ca6abced86
[31] https://www.nationalgrideso.com/future-energy/future-energy-scenarios/fes-2021/documents

2.1.6 Methodology and Climatic years

The methodology applied will take into account the latest European methodologies approved in 2020, as applied in the Adequacy and Flexibility study 2022-32 published in June 2021.

Regarding ERAA, note that an implementation plan is foreseen to take the recently adopted European methodologies gradually into account over the period until 2023-2025. The first ERAA report published in 2021 is only a first step in the implementation of these methodologies.

Regarding climatic years, Elia will use the 'forward looking' climate database developed by Météo-France and also used by RTE in its adequacy assessment. Such methodology was already extensively presented (several sources are available detailed the methodology used by Météo-France) during the Adequacy and Flexibility public consultation[32].

Such approach is fully in-line with the requirements of the adopted ERAA methodology which indicates that the future PECD should reflect evolutions of the climate conditions (Article 4 (f)). Elia aims to follow this evolution in order to better grasp this future requirement of the ERAA methodology, although the final implementation choice by ENTSO-E (as 3 options are left) will only be finalized in the coming years. ENTSO-E has indicated in its implementation plan that the target option is to use the first option (which is the one also chosen by Elia in this CRM calibration report).

It is also worth noting that the latest European adequacy study on which such calibration report should be based (ERAA21) is still based on the previous PECD containing more than 30 historical climate years.

The complete methodology is detailed on the webpage of the Adequacy and Flexibility public consultation and in §4.3 of the Adequacy and Flexibility study 2022-32, published in June 2021.

[32] https://www.elia.be/en/public-consultation/20201030_public-consultation-on-the-methodology-the-basis-data-and-scenarios-used

2.1.7 Economic parameters

The last point of this section is dedicated to data and assumptions for the scenario's economic parameters, necessary to calculate as precisely as possible the market revenues that are required to determine the missing money of technologies in order to calibrate the price parameters of the demand curve and to determine the intermediate price cap.

Given the current very uncertain context with high prices and geopolitical risk, it is virtually impossible to make accurate forecasts of the economic parameters for the 2027-28 Delivery Period. As such, 1 base case and 2 sensitivities are proposed regarding the economic parameters to account for these uncertainties. The base case presented here assumes that the war in Ukraine will no longer affect the economic parameters in the 2027-28 Delivery Period. As such, the parameters presented in section 6 of the Excel file are calculated as an interpolation between the latest forward prices on 18/02/2022 (before the war in Ukraine) and the price forecasted for 2030 in the World Energy Outlook of 2021[33], expressed in €2020. The forward price is converted to €2020 by accounting for inflation (see Table 7) though the following formula:

$$Price\ in\ €\ 2020 = \frac{Price\ in\ €2022}{(1 + inflation\ 2020) * (1 + inflation\ 2021)} = \frac{Price\ in\ €2022}{1{,}031168}$$

Year	Inflation rate
2019	1,4%
2020	0,7%
2021	2,4%
2022	5,5%
2023	1,1%
2024	1,2%
2025	1,5%
2026	1,6%
2027	1,6%

Table 6: overview of the yearly inflation rates

The inflation rates for 2019-2021 are taken from the World Bank [34] values for 2022-2027 are taken from the Federal Planning Bureau[35].

The prices include the fuel cost for oil, gas and coal, expressed in € 2020/MWh, and the CO_2 cost, expressed in €2020/tCO_2. The oil price is derived from the crude oil price by

[33] https://www.iea.org/reports/world-energy-outlook-2021
[34] https://data.worldbank.org/indicator/FP.CPI.TOTL.ZG?locations=BE
[35] https://www.plan.be/uploaded/documents/202202241058510.FOR_MIDTERM2227_12588_N.pdf

an increase of 28% based on historical data, in line with the Adequacy and Flexibility 2021 study.

The update in comparison with the previous CRM calibration 26-27 is presented in Table .

Data	CRM calibration 26-27	CRM calibration 27-28	Sources
Gas [€ 2020/ MWh]	21.4	24.4	Ice Endex TTF GAS (elexys.be); World Energy Outlook (IEA) 2020
Coal [€ 2020/ MWh]	8.7	12.7	Coal (api2) CIF ARA (argus-McCloskey) (cmegroup.com) World Energy Outlook (IEA) 2020
Oil [€ 2020/MWh]	38.4	46.4	Crude oil futures (cmegroup.com)
CO_2 [€ 2020/tCO_2]	46.9	97.3	EUA futures (sandbag.be) World Energy Outlook (IEA) 2020

Table 7: Update on economic parameters

#Q5 – Economic parameters

Do you find the proposal for fuel and CO_2 prices relevant? Would you rather consider one sensitivity with lower or higher prices? Do you have any alternative proposal for those parameters?

The 2 sensitivities regarding the economic parameters, with higher and lower prices respectively, will be detailed in §2.2.4.

2.2 Sensitivities that could be integrated in the reference scenario

This section presents the sensitivities that could be integrated in the reference scenario, according to article 3, §4. The purpose of the sensitivities is to take into account additional assumptions that can have an impact on the Belgian security of supply. Stakeholders are also free to propose additional quantified sensitivities.

The sensitivities have been selected by Elia in collaboration with FPS and in concertation with the CREG. These sensitivities, the associated assumptions and data modification and their purpose are then submitted to public consultation. Elia will then provide a public consultation report integrating the feedback from the stakeholders and recommendations.

Based on this report, CREG will propose to the Minister a set of data and assumptions that constitutes a reference scenario on which FPS transmits an advice. Finally, the Minister decides which sensitivities should be applied in order to establish the reference scenario by September 2022.

The sensitivities menu is presented in the Excel, section 7. This explanatory note explains further the purpose, the source and the impact of each proposed sensitivity.

Figure 7 presents the different sensitivities proposal for the Y-4 auction of 2027-28 Delivery Period. It includes:

- 4 sensitivities on the French nuclear availability;
- 1 sensitivity on the non/strict achievements of the FB CEP rules for 2027;
- 2 sensitivities related to the impact of a possible CO_2 threshold;
- 2 sensitivities on prices;
- 1 sensitivity on the electricity consumption

Any feedback on the proposed sensitivities or additional proposals for sensitivities (ideally including sources) are more than welcome and will be dealt with carefully by Elia.

French nuclear availability 1	**Decreased French nuclear availability in continuity of last year's reference scenario** Lower availability by 2 units on average during winter
French nuclear availability 2	**Decreased French nuclear availability based on historical figures** Lower availability by 4 units on average during winter
French nuclear availability 3	**Decreased French nuclear availability based on historical figures** Lower availability by 6 units on average during winter
French nuclear availability 4	**Decreased French nuclear availability based on historical figures** Lower availability by 8 units on average during winter
FB CEP rules	**Non achievements of the CEP rules for 2027 to reflect the uncertainty on capacity calculation.** Fixed RAM 70% instead of 70% minRAM
TJ closure	**Closure of turbojets due to possible CO2 threshold** -158 MW
OCGT closure	**Closure of both turbojets and old OCGT due to possible CO2 threshold** -511 MW
High prices	**Maintain high prices in Europe** Higher fuel costs (35,4 €2020/MWh for gas and 17,1 €2020/MWh for coal)
Low prices	**Back to low prices in Europe** Lower fuel costs (19,8 € 2020/MWh for gas and 8,6 €2020/MWh for coal)
Lower demand	**Lower demand in Belgium due to high prices** Lower yearly consumption due to high electricity prices

Figure 7: Sensitivities menu

2.2.1 French nuclear availability

4 different sensitivities are associated to the French nuclear availability, which can have a significant impact on Belgian adequacy, as demonstrated in the Adequacy and Flexibility study 2022-32 (Figure 5-11). Those sensitivities propose additional unavailability of the nuclear units in France in comparison with the maintenance profiles provided by RTE in the framework of the ERAA 2021.

The first sensitivity takes into account a reduced nuclear availability of 2 units for winter periods. This sensitivity is proposed in line with the two first Y-4 CRM auctions for Delivery Year 2025-26 and 2026-27[36] which included this sensitivity.

The three other sensitivities consider a higher unavailability of nuclear units during winter periods, leading to a reduction by 4, 6 or 8 units compared to the availability profiles foreseen in the framework of the ERAA 2021.

36 https://economie.fgov.be/nl/themas/energie/bevoorradingszekerheid/capaciteitsremuneratiemechanis/veilingen-het-kader-van-het

The reasoning behind this scenario is justified by historical observations complemented with recent observations on the unavailability of the French nuclear fleet:

- The French nuclear fleet is going through major overhauls to extend the lifetime of its ageing fleet beyond 40 years. Those overhauls will last a decade at least.
- The maintenance calendar was greatly affected by the COVID sanitary restrictions leading to the situation experienced the last 2 winters in France with consequences for the upcoming winters as well.
- In addition, recent found corrosion defects in some weldings will greatly impact the availability of all nuclear reactors in the coming 5 years as they will be undergoing inspections and possible works[37].
- The nuclear fleet is very vulnerable to generic issues given the same technological conception used in the reactors. A similar situation was already experienced during winter 2016-17
- RTE expects that the nuclear uncertainty is of about 100 TWh in 2030[38], corresponding to around 11 GW if spread over the year.

In order to quantify the amount of units that was unavailable historically (on top of the forecasted capacities), an analysis was conducted based on REMIT data published by EDF and compared to the average capacity that was unavailable due to outages in the same winters but not foreseen in the forecast 1 or 2 years in advance. This result is presented on Figure 8.

[37] Nucléaire. EDF recherche de nouvelles corrosions sur ses réacteurs, une vague d'arrêts à prévoir (ouest-france.fr)
[38] BP50_Principaux résultats_fev2022_Chap14_Analyse des dynamiques_0.pdf (rte-france.com)

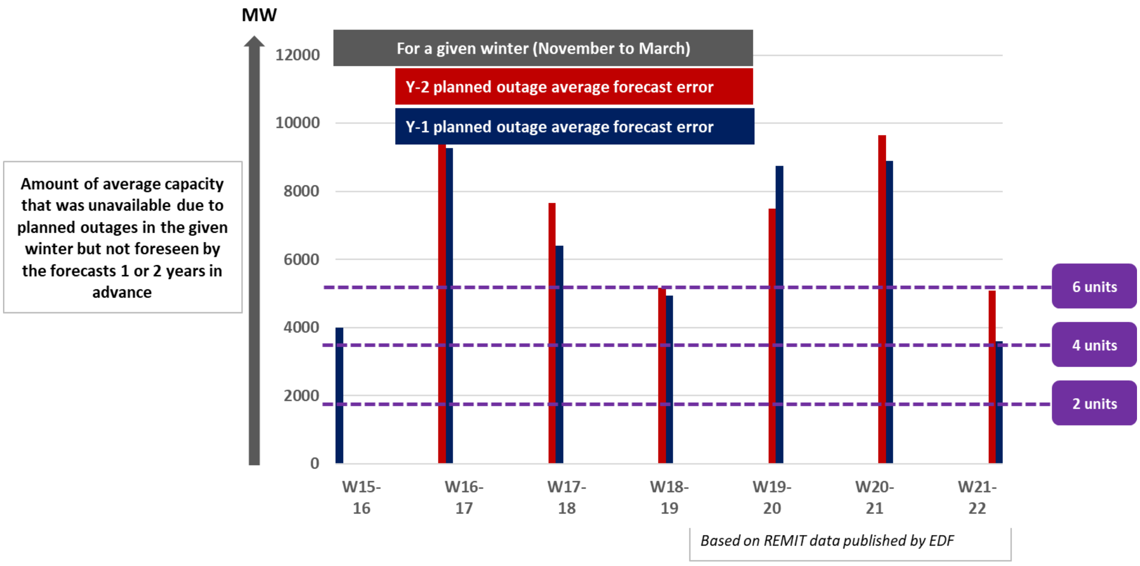

Figure 8: French nuclear unavailability during winter months in France

2.2.2 Flow-based CEP rules

Several reasons can be put forward to justify the addition of sensitivity on the applied flow-based domains in the context of this study.

Firstly, in exceptional circumstances, the minRAM factor can be set below the targeted legal threshold by a TSO if required to maintain operational security (See CEP article 16.3[39]). This type of events cannot be excluded and a minRAM 70% can therefore not be guaranteed at every hour and on every CNEC. The complexity and uncertainties linked to the forecasting of remedial actions (RA) are one of the main factors justifying that such operational security exceptions could occur during the period covered by this study. Such exceptional circumstances might arise during near scarcity periods. For instance, such a situation was observed during the cold wave that hit Central Europe in 2020, leading to a reduction in crossborder capacities by Tennet NL.

The need for sensitivity could be further justified in order to capture the potential delay in meeting the 70% minRAM target. Any country that would be facing unforeseen difficulties to meet the legal target, could still legally request a derogation after 2025.

[39] https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:32019R0943&from=EN#d1e2713-54-1

Furthermore, the current legislation does not exclude the inclusion of grid elements internal to a bidding zone in the CNE list, if it is demonstrated with a Cost Benefit Analysis (CBA) that adding the internal grid element is a more economically efficient solution in comparison to – amongst others – a bidding zone reconfiguration. Given that the flow-based domains calculated in this study only consider cross-border CNECs, decreasing the available margin on those cross-border CNECs can be considered as a proxy to the inclusion of internal constraints into the market coupling.

If a country is facing systemic difficulties to meet the CEP requirements, a bidding zone split could constitute a solution forward. It can be expected that such a bidding zone split will neither be decided upon nor be applied overnight. As an example, the split of the German-Austrian bidding zone has taken about 2 years to implement, starting November 2016 when ACER issued a legally binding decision for the German-Austrian border, followed by the German and Austrian regulatory authorities (BNetzA and E-Control) agreement on May 2017 and finally with the split between Germany and Austria taking effect on 1 October 2018[40]. The impact of such a bidding zone split would be difficult to estimate: while it might have a mitigating impact on initial flows affecting the flow-based domain, in general splitting bidding zones will lead to additional constraints to the market coupling, as former internal grid elements will become cross-border elements.

Finally, as mentioned earlier, in determining the flow-based domains for winter periods, the optimistic assumption is taken in this study that the transmission grid is always fully available. While covering the potential impact of any single contingency taking place, prior to such a contingency, a European transmission grid without planned outages and without forced outages that cannot be quickly repaired is assumed.

The abovementioned arguments justify the consideration of a sensitivity fixed RAM 70% instead of a minRAM 70%.

[40] https://www.apg.at/en/Energiezukunft/Strompreiszone

2.2.3 Uncertainties on Belgian thermal units

This sensitivity is related to the impact of a potential new CO_2 threshold that would be introduced as part of the CRM on Belgian units.

Currently, the Clean Energy Package (CEP) imposes a double criteria regarding CO_2 emission:

- For new units : < 550 g/kWh;
- For existing units: < 550 g/kWh or < 350 kg/kW/year.

The second criteria for existing units allows every unit in Belgium to take part in the electricity market, limiting only the amount of running hours of the unit if it emits too much CO_2 in g/kWh (following the first criteria). Indeed, in that case, the second yearly criteria will be the one limiting the energy generated by the unit.

If the criteria are updated and that no more yearly criteria is considered for existing units, it might results in a certain number of units being at risk as they could not participate in the CRM auctions anymore.

This sensitivity proposes to take into account this risk on the units emitting the most CO_2 per MWh in Belgium.

2.2.3.1 TJ closure

In this sensitivity, we assumed that the turbojets in Belgium will close due to the potential new CO_2 threshold. This would results in 158 MW not available in the Belgian electricity market.

2.2.3.2 OCGT closure

In this sensitivity, we assumed that both the turbojets and old OCGT in Belgium will close due to the potential new CO_2 threshold. This would results in 511 MW not available in the Belgian electricity market.

2.2.4 Uncertainties on prices

Given the current very uncertain context with high prices and geopolitical risk, it is virtually impossible to make accurate forecasts of energy prices for the 2027-28 Delivery Period. As such, 2 sensitivities are proposed regarding energy prices to account for these uncertainties, 1 with higher prices and 1 with lower prices. The base case presented before assumes that the war in Ukraine (and its geopolitical consequences) will no longer affect the economic parameters in the 2027-28 Delivery Period and is therefore calculated using the value of futures on 18/02/2022, or right before the start of the war in Ukraine. The 2 price sensitivities are presented below and an overview of the different price assumptions is visible in Figure 9 .

It is proposed to only change the coal and gas prices. The oil prices is more linked to world/global economics and geopolitics while the CO_2 price is also affected by other measures.

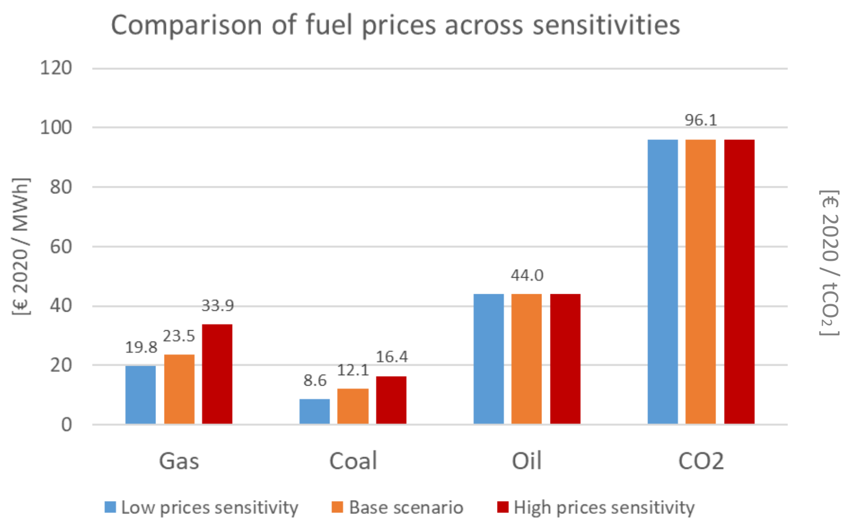

Figure 9: overview of the price assumptions for the different sensitivities

2.2.4.1 High prices

This sensitivity assumes continued geopolitical instability reflected in the energy prices. In this sensitivity the fuel prices for gas and coal are calculated by interpolating between the value of the last available futures on 19/04/2022 converted to €2020 and the respective WEO 2030 values given in €2020. The result of which is visible in Table 6.

Fuel	Price
Gas in € 2020/MWh	35,4
Coal in € 2020/MWh	17,1

Table 6: overview of fuel prices in high prices sensitivity

Given that the ERAA 21 expected oil price for 2025 and the WEO 2030 oil price are the same and higher than the oil price of the base scenario, the proposal is to keep the lower value of the base scenario in this sensitivity.

2.2.4.2 Low prices

Energy prices were already high before the war in Ukraine due to various reasons (COVID-19, low reserves, low investments in fossil fuel production…). It can therefore be argued that a return to a situation with lower prices is possible. This situation will be covered in this sensitivity. In this sensitivity, the fuel prices are calculated as an interpolation between the ERAA 21 values for 2025 and the WEO 2030 prices which are both expressed in €2020.

Fuel	Price
Gas in € 2020/MWh	19,8
Coal in € 2020/MWh	8.6

Given that the ERAA 21 expected oil price for 2025 and the WEO 2030 oil price are the same and higher than the oil price of the base scenario, the proposal is to keep the lower value of the base scenario in this sensitivity.

2.2.5 Lower demand due to high prices

This sensitivity aims to evaluate the impact on the average yearly electricity consumption in case of high prices. As electricity prices are expected to remain high in the short-term, it might affect the total demand for electricity through price elasticity of the electricity demand.

This effect is proposed to be taken into account in this sensitivity and therefore needs to be quantified. An estimation will be provided when updating the total electricity demand figures with the latest economic forecast from Plan Bureau for the 'base' and 'high prices' sensitivities proposals.

3 Other parameters

This chapter describes the additional parameters that have to be submitted to public consultation according to article 5, §2, 3° to 5° of the Royal Decree, but that are not fixed by the Minister. This includes the sources of scenarios for periods after the Delivery Period in order to calculate the market revenues accordingly, the preselected capacity types to be added to the reference scenario in order to reach the security of supply criteria and the intermediate price cap parameters.

3.1 Preselected capacity types

This section details the parameters included in the scope of this public consultation towards the preselected capacity types that shall apply in the Y-4 auction for Delivery Period 2027-28.

Once the reference scenario is defined by the Minister, it does not mean that this scenario meets the legal security of supply criteria, as defined in article 7undecies, §3 of the electricity law. Indeed, the scenario choice takes into account data and assumptions from the latest European or National Resource and Adequacy Assessment updated with the most up-to-date available information and might take into account some sensitivities in or out of the Belgian market zone that can have an impact on the Belgian security of supply. The next step in the methodology is therefore to calibrate the scenario to the security of supply criteria in order to reach the right volume to be procured for the Y-4 auction of 2027-28 Delivery Period.

The proposed preselected capacity types are presented in the Excel file (section 8). Five categories are mentioned: semi-baseload, peakers 1, peakers 2, batteries and demand-side response. Each category is associated with a typical technology available on the Belgian energy market.

- Volume
  For the first four categories, incremental capacity of the reference technology (new CCGT, new OCGT, new IC engine and new large-scale batteries) is added step by step.
  For demand-side response, incremental capacity is added to each of the categories already defined for the Belgian market zone (see §2.1.2.2 proportionally to each demand-side response category size.
- Marginal Price
  For the first three categories, the marginal price will be calculated based on the parameters associated with a new entrant of each technology.
  For demand-side response, the marginal price is defined based on a weighted average of the existing demand-side response categories.
  No marginal price is associated to large-scale batteries.

Note that the information presented in the framework of the Y-4 auction for Delivery Period 2027-28 also includes CAPEX [€2020/kW], FOM [€2020/kW] and economic lifetime [years]. Those data is in line with the Adequacy and Flexibility study 2022-32, except for batteries for which an additional source is integrated[41].

#Q6 – Cost parameters for new units Do you agree with the cost parameters presented in the Excel file for new units? If not, could you give some insights in the impact of the current geopolitical context, with among others higher material costs/supply chain issues, on these numbers?

As long as the security of supply criteria are not reached, additional capacity from one of these categories is added step by step. The step size will be in line with the European Resource and Adequacy Assessment methodology and shall not exceed 100 MW. For each step, capacity will be iteratively added based on an economic optimization loop.

At the end of this process, the security of supply criteria are reached and a mix of capacities from the different categories will be selected based on the defined economical loop.

Royal Decree Reference	
Art. 6. §1er. Le gestionnaire du réseau s'assure que le scénario de référence tel que déterminé selon l'article 3, §7, répond aux critères pour la sécurité d'approvisionnement requis par l'article 7undecies, §3, de la loi du 29 avril 1999 en ajoutant, si nécessaire, une capacité supplémentaire à la zone de réglage belge : 1° provenant des types de capacité présélectionnés selon l'article 10 et proposés par le gestionnaire de réseau dans la consultation publique visée à l'article 5 et ensuite choisis par le gestionnaire de réseau en collaboration avec la Direction générale de l'Energie et en concertation avec la commission ;	**Art. 6**. §1. De netbeheerder verzekert zich ervan dat het referentiescenario zoals bepaald volgens artikel 3 §7 beantwoordt aan de criteria voor de bevoorradingszekerheid die worden geëist door artikel 7undecies, § 3, van de wet van 29 april 1999 door, indien nodig, aan de Belgische regelzone bijkomende capaciteit toe te voegen: 1° afkomstig van de volgens artikel 10 voorgeselecteerde types van capaciteit die voorgesteld worden door de netbeheerder ter openbare raadpleging bedoeld in artikel 5 en daarna door de netbeheerder in samenwerking met de Algemene Directie Energie en in overleg met de commissie gekozen worden;

[41] Cole, Wesley, A. Will Frazier and Chad Augustine. 2021. Cost Projections for Utility-Scale Battery Storage: 2021 Update. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-79236. https://www.nrel.gov/docs/fy21osti/79236.pdf

2° d'une manière itérative sur la base d'une boucle d'optimisation économique avec l'incrément comme utilisé dans l'évaluation de l'adéquation des ressources à l'échelle européenne ou nationale visée aux articles 23 et 24 du Règlement (UE) 2019/943 et de maximum 100 MW.	2° op een iteratieve manier op basis van een economische optimalisatielus op basis van incrementele stappen zoals gebruikt in de Europese of nationale beoordeling van de toereikendheid van de elektriciteitsvoorziening, bedoeld in de artikelen 23 en 24 van Verordening (EU) 2019/943 en van maximaal 100 MW.

3.2 Scenario used for post-Delivery Periods

This section details the parameters included in the scope of this public consultation towards the scenarios for the periods after the 2027-28 Delivery Period used to calculate the market revenues for the technology with a lifetime longer than one year.

Indeed, point B of the demand curve is calibrated at the net-CONE, which is equal to the missing money of the technology with the lowest missing money. Three parameters are required to determinate it: the gross-CONE, the market revenues and the ancillary services revenues (defined in §3.3.3). Just as the gross-CONE takes into account the costs of the entire lifetime for the reference of each technology, market revenues must also be determined on this period. This requires more than the Delivery Period scenario to have a correct estimation. This is the reason why additional existing scenario from public available sources are taken into account. If a scenario is not available for one of the years of each reference technology lifetime, an interpolation is made between the values of the years for which a public scenario is available.

The proposed post-Delivery Period scenarios are presented in the Excel file (section 9). For 2028, 2030 and 2032, the proposal is to take the Adequacy and Flexibility study 2022-32 as public source for the targeted year. For later years, it is also proposed to use the Adequacy and Flexibility study using the last year simulated 2032 as a proxy in order to keep consistency with the other time horizons and to use recent data. For each of these time horizons, a scenario as close as possible to the reference scenario of 2027-2028 Delivery Period defined by the Minister will be selected.

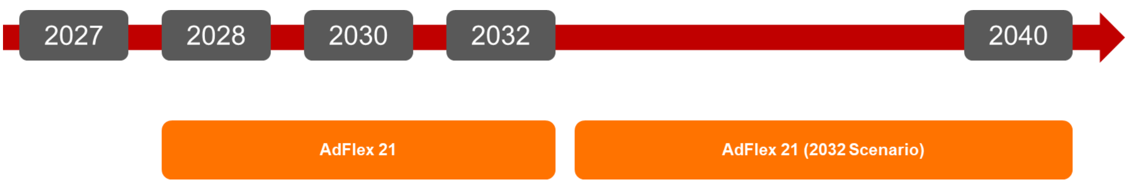

Figure 10: Selection of the scenarios and sources post-Delivery Year for the market revenues calculation

Royal Decree Reference	
Art. 10. §6. (…) Si le scénario de référence n'est pas disponible pour une année sur la durée de vie de la référence pour chaque technologie, une interpolation est réalisée entre les valeurs des années pour lesquelles le scénario de référence existe, éventuellement corrigé par des données disponibles complémentaires.	Art. 10. §6. (…) Indien het referentiescenario niet beschikbaar is voor een jaar uit de levensduur van de referentie voor elke technologie, wordt een interpolatie uitgevoerd tussen de waarden van de jaren waarvoor het referentiescenario bestaat, eventueel bijgestuurd door bijkomende beschikbare gegevens.

3.3 Intermediate Price Cap parameters

In this section, the parameters are described that are included in the scope of this public consultation towards the calibration of the intermediate price cap that shall apply in the Y-4 auction for Delivery Period 2026-2027.

3.3.1 Shortlist of technologies

In accordance with art. 5, §2, 5° of the Royal Decree on the volume methodology (cf. section 1), this public consultation includes a shortlist of existing technologies reasonably considered available during the Delivery Period 2026-2027, and deemed relevant for the calibration of the intermediate price cap. The shortlist is presented in the Excel file (section 10.1).

Based on the expert study delivered by Fichtner (2020)[42] followed by a peer review realized by AFRY (2020)[43] and Elia's assessment taking into account the remarks of the

[42] Conform art. 17, §1 of the Royal Decree, ELIA has initiated a study – in concertation with the CREG – by an independent expert to determine the cost components associated to the technologies deemed relevant towards the calibration of the intermediate price cap. The resulting expert study by Fichtner titled "Cost of Capacity for Calibration of the Belgian Capacity Remuneration Mechanism (CRM)" is available at the following link: https://www.elia.be/-/media/project/elia/elia-site/users-group/crm-implementation/documents/20201214_fichtner-report-cost-of-capacity-crm_en.pdf.

[43] Several market parties pointed out in their reaction to the public consultation held by Elia between the 5th of May and 5th of June 2020 their willingness to see another expert perform a peer review of the study realized by Fichtner in 2020 on the 'Cost of Capacity for Calibration of

public consultation done by Elia on the same matter in view of Delivery Period 2025-2026, this shortlist of technologies is believed to represent a list of technologies likely to include the technology with the highest missing-money across the whole set of existing technologies reasonably expected to be available during the Delivery Period 2026-2027. Therefore, this shortlist serves as a basis towards the calibration of the intermediate price cap.

Building further on the above mentioned studies realized in 2020 and on the feedback received from market parties during the public consultation, Elia considers that the shortlist of technologies that was defined for the calibration of the IPC for the Delivery Period 2025-26 is still relevant and should apply for the calibration of the IPC for the Delivery Period 2026-27. Moreover, according to what is foreseen in the article 17 §1 of the proposal of Royal Decree Methodology, an update of these studies does not seem to be required by Elia: it is indeed stated that an update of the study from the independent expert is required at least every three years or in case of significant market evolutions. None of these criteria seems to be fulfilled and therefore to justify an update of the studies realized by Fichtner nor AFRY.

Royal Decree Reference	
Art. 18. §1er. Le gestionnaire du réseau détermine, sur la base de l'étude visée à l'article 17, après la consultation publique visée à l'article 5, une liste réduite de technologies existantes qui seront raisonnablement disponibles et qui seront considérées pour la détermination du prix maximal intermédiaire.	**Art. 18.** §1. De netbeheerder stelt op basis van de studie bedoeld in artikel 17, na de openbare raadpleging bedoeld in artikel 5, een beperkte lijst op van bestaande technologieën die redelijkerwijs beschikbaar zullen zijn en die in aanmerking genomen zullen worden voor de bepaling van de intermediaire maximumprijs.

the Belgian Capacity Remuneration Mechanism(CRM'. This peer review was realized by AFRY and presented in TF CRM on the 30th of October 2020. The study is available at the following link: https://www.elia.be/-/media/project/elia/elia-site/users-group/crm-implementation/documents/20201214_afry_peer-review-of-annual-fixed-costs-for-belgian-crm_en.pdf.

3.3.2 Cost components

In addition to a shortlist of technologies and beyond the legal requirements regarding the scope of the public consultation for the calibration of the intermediate price cap (i.e. the above mentioned shortlist of technologies), like for the set of parameters for the Y-4 auction for the Delivery Period 2025-26, this public consultation also consults on various cost components relevant for the calibration of the intermediate price cap. In particular, yearly fixed operation and maintenance (O&M) costs and the activation cost for an availability test are consulted upon.

The yearly fixed operation and maintenance (O&M) costs (cf. art. 18, §2, 1° and 2° of the Royal Decree) have been assessed from the expert study realized by Fichtner (2020) followed by a peer review done by AFRY (2020). As mentioned above, Elia is of the opinion that the results coming from these studies are still robust and valid for the calibration of the IPC for the Y- 4 auction of the Delivery Period 2026-2027. Elia sees therefore no reason to update these costs which will be used for the calibration of the IPC for the Delivery Period 2026-2027. They are presented per technology included in the shortlist in the Excel file (section 10.1) and include the following components:

1. Fixed operating costs including personnel costs, administrative costs, electricity and gas transmission charges (where applicable);
2. The O&M insurance for general liability, machine breakdown and interruption of operation of the power plant;
3. Fixed maintenance costs including intrayear maintenance and a provision for major overhauls that do not necessarily take place on a yearly basis.

In accordance with the Royal Decree (art. 18, §2, 6°), the ***activation cost for an availability test*** is to be considered only for technologies with a high short-run marginal cost. Indeed because of the high short-run marginal cost these technologies are unlikely to be activated. As this makes it harder to monitor their availability in the market they are more likely candidates for availability tests. A CRM candidate offering such a CMU is therefore more likely to also include a provision for such an availability test in its bid. Among the technologies included in the shortlist, the activation cost is deemed relevant only for the *Demand Side Response* technology, considered to be characterized by a high short-run marginal cost.

The activation cost – presented in the Excel file (section 10.2) – is therefore to be associated to the *Demand Side Response* technology and is derived from the historical data published on the Elia website regarding contracted volumes and prices for Strategic Demand Reserves (SDR).[44] Considering the average activation price for SDR for winter period 2015-2016[45] for a 4 hour activation (associated with a derating factor X,

[44] https://www.elia.be/en/suppliers/supplier/energy-purchases/strategic-reserve-volume-and-prices
[45] Winter 2015-2016 is still the most recent winter period in which SDR was contracted.

expressed in %), and assuming one availability test of 15 minutes per year, the activation cost is calculated as follows:

$$\frac{0{,}73673€}{kWh} * 0{,}25h * \frac{1}{X}.$$

#Q7 – Cost parameters for existing unit

Do you agree with the cost parameters presented in the excel file for existing units?

If not, could you give some insights, among others on the impact of the current geopolitical context (higher material costs,…) on these numbers?

3.3.3 Net revenues from the provision of balancing services

Finally, this public consultation also includes a reasoning regarding the consideration of net revenues from balancing services (cf. art. 19, §3 of the Royal Decree) towards the calibration of the intermediate price cap, which goes beyond the legally required scope regarding the public consultation for the calibration of the intermediate price cap. However, Elia considers it opportune to also consult on this specific aspect given that stakeholder feedback can only contribute to a better application of the principles put forward in the Royal Decree.

For the sake of clarity, no specific values are consulted upon in the Excel file (section 10.3), only a general approach regarding the consideration of net revenues from the provision of frequency-related balancing services for each of the technologies included in the shortlist is presented in this document.

The net revenues from the provision of frequency-related balancing services, in order to avoid double counting and to consider only net revenues, will be considered to the following extent:

- ***FCR***: No net revenues from the provision of FCR are deemed relevant for any of the technologies included in the shortlist. Battery storage – not included in the shortlist of technologies – is considered likely to become the dominant technology to provide FCR towards the relevant Delivery Period, i.e. by November 2026. Battery storage is not included in the shortlist of technologies, because, as mentioned in Fichtner (2020): "*Batteries are usually built for very specific system services, such as Frequency Containment Reserves (FCR), which cover their investment. They are therefore unlikely to have the highest amount of missing money as their remuneration depends on a structural need by a specific party (e.g. the TSO for FCR) rather than the instantaneous electricity price on the market".*
- ***aFRR***: No net revenues from the provision of aFRR are deemed relevant for any of the technologies included in the short list. It is assumed that technologies that provide aFRR arbitrage between the provision of aFRR and selling energy. Indeed, by offering a price for an aFRR reserve contract, the party knows that the capacity can no longer be used for delivering energy in the energy market. Its

price for participating in the aFRR auctions will therefore account for the potential missed revenues from selling energy instead. Therefore, aFRR reservation fees are assumed not to represent a net revenue on top of the inframarginal rents earned on the energy market. Besides, any relevant must run costs following the reservation to provide aFRR are considered included in the trade-off between providing aFRR and selling energy, meaning that such must-run costs do not represent any additional net cost.

- ***mFRR***: The perfect arbitrage principle presented above for technologies providing aFRR, seems not to apply for some technologies in the Belgian mFRR market. Indeed, the *Turbojet* and *Demand Side Response* technologies – both included in the shortlist of technologies – are believed to rely structurally on the mFRR reservation fees as primary source of income, seemingly unable to derive equivalent revenues from the energy market. According to the AFRY study, it can be assumed as well that *OCGTs*, included in the shortlist of technologies considered for the IPC calibration as well, may earn part of their revenues from the mFRR market: indeed, considering the current market conditions and taking into account the increasing quantities of renewable energy sources, it does not seem unreasonable to assume that OCGTs may derive a part of their revenues from the mFRR market. On the contrary, for other technologies that are capable to provide mFRR, the prospective incomes that can be derived from the mFRR market may not be sufficiently attractive, such that they do not replace the technologies that currently provide mFRR. Therefore, net revenues from the provision of mFRR are deemed relevant for the *OCGT, Turbojet* and *Demand Side Response* technologies included in the shortlist. For these technologies, the projected inframarginal rents from the energy market are weighed against a percentage of the weighted average mFRR reservation fee. Revenues shall be considered from the service, i.e. selling energy or providing mFRR, which leads to the highest value.

4 Summary of the questions to stakeholders

#Q1 – RES generation

Do you agree with the proposed updates for solar, wind onshore and wind offshore based on the latest available information? If not, do you have additional information or know of developments that should be taken into account according to you?

#Q2 – Nuclear forced outage rate

Do you agree with this methodology and do you have comments on the relevant parameters to be taken into account?

#Q3 – Demand, including number of Electric Vehicles and Heat Pumps

Do you agree with the values provided for EV and HP? Would you propose another value (increasing or decreasing), why and based on which source?

Do you agree with the proposed total demand? Would you propose another value, why and based on which source?

#Q4 – Impact of European measures on demand and DSR

How would you quantify the impact that the latest European plans (Fit For 55, REPowerEU) and national ambitions could have on the consumption and demand-side response volumes?

#Q5 – Economic parameters

Do you find the proposal for fuel and CO_2 prices relevant? Would you rather consider one sensitivity with lower or higher prices? Do you have any alternative proposal for those parameters?

#Q6 – Cost parameters for new unit

Do you agree with the cost parameters presented in the Excel file for new units?

If not, could you give some insights in the impact of the current geopolitical context, with among others higher material costs/supply chain issues, on these numbers?

#Q7 – Cost parameters for existing unit

Do you agree with the cost parameters presented in the excel file for existing units?

If not, could you give some insights, among others on the impact of the current geopolitical context (higher material costs,…) on these numbers?

5 Appendix: Elements to determine for the availability of the Belgian nuclear units

5.1 Methodology applied for determining the availability of Belgian nuclear power in previous adequacy assessments

The availability of nuclear units used in the 'CENTRAL' scenario of the Adequacy & Flexibility studies was based on the following categorization[46]:

- **Planned maintenance** based on expected planning (REMIT data). This was precisely modelled by taking into account the exact dates foreseen for each unit for each year;
- **Forced outages**
    - **'Technical' Forced Outages**. These outages were taken into account with a force outage rate based on historical values;
    - **'Long-lasting' Forced Outages**: additional unavailability not covered by the two previous categories which are unpredictable and result in long-lasting events. Those events are based on the information and communication available on the AFCN/FANC website[47].

In the framework of the Adequacy & Flexibility study from June 2021, the additional unavailability due to 'long-lasting' forced outages for nuclear units was expressed in [GW]. This annex aims to provide an equivalent value in [%] for these events to better reflect the contribution of the technology to security of supply.

5.2 Determining the availability of Belgian nuclear units

Nuclear units being thermal with daily schedule CMUs, their availability is calculated based on an average of 10-year availability data. Regarding availability of nuclear power plants, 4 independent and cumulative statuses can be distinguished, considering that forced outages could be split between 'technical' and 'long-lasting' forced outages:

- The unit was **available** (presented as "Available" in §5.4).
- The unit was in a **planned outage**. A planned outage is considered as usual maintenance but also includes longer planned maintenance periods needed to solve issues encountered after a 'long-lasting' forced outage (presented as "Planned Unavailability" in the analysis in Annex). Regular maintenance is assumed to be performed outside of the critical periods for security of supply

[46] A small adaptation was performed by changing 'additional unavailability' to 'long-lasting' forced outages and by grouping the two last category into a single 'forced outages' naming.
[47] https://afcn.fgov.be/fr/dossiers/centrales-nucleaires-en-belgique

even though some planned outage events have been observed during winter based on historical data. Note that planned outage also includes the long-term operations (LTO) outage periods which are significantly longer than regular planned outage periods.

- The unit was in **'technical' forced outage**. A 'technical' forced outage is usually an unexpected event or malfunction leading to the shutdown of the unit in order to fix a well-defined and limited issue (presented as "Technical Force Outage" in §5.4). Those events are assumed to be independent from the climatic conditions.

The unit was in a '**long-lasting' forced outage**. A long-lasting forced outage is an unpredictable event, leading to a long-lasting shutdown of the unit (presented as "Long-lasting Force Outage" in §5.4). Those events are assumed, similar to 'technical' forced outages, to be independent from the climatic conditions, meaning that it could happen anytime during the year and hence impact security of supply. This assumption is confirmed by looking at historical data. Note however that longer planned outages required to fix these long-lasting events are not considered in this category. The split between 'long-lasting' forced outage and longer planned outages required to fix those is based on information of AFNC/FANC website and on a case by case analysis on planned outages of the different nuclear units. More details can be found in "Details on unit per unit type of historical availability events".

5.2.1 Methodology

The 'technical' forced outage (TFO) rates were already calculated in the framework of the Adequacy and flexibility study 2021 as explained above.

In order to calculate the rates of the planned and 'long-lasting' forced outages, historical daily nomination data were used for the period 2012-2021.

Regarding 'long-lasting' forced outages (LLFO), the following formula is used in order to calculate the corresponding rate:

$$'Long\ lasting'\ FO\ rate = \frac{(TFO\ energy\ + LLFO\ energy)2012 \rightarrow 2021}{(TFO\ energy + LLFO\ energy + Available\ energy)2012 \rightarrow 2021} - 'Technical'\ FO\ rate$$

Finally, the planned outage rate is calculated as the planned unavailability on the total period:

$$PO\ rate = \frac{PO\ days\ 2012 \rightarrow 2021}{Total\ days\ 2012 \rightarrow 2021}$$

Note that 'technical' forced outages, 'long-lasting' forced outages and planned outages should be considered as independent and cumulative.

5.2.2 Events considered as 'long-lasting' forced outage

Regarding 'long-lasting' forced outages, a defined number of events were considered, based on information available on AFCN/FANC website:

1. Indications of microflakes in the nuclear vessel of Doel 3 and Tihange 2[48] ;
2. Doel 4 sabotage[49] ;
3. Concrete degradation on bunkers of Doel and Tihange (D3/D4/T2/T3)[50] ;
4. Concrete issue during LTO on Tihange 1[51].

The unit-by-unit details are presented in "Details on unit per unit type of historical availability events".

5.2.3 Historical availability of nuclear units

The different indicators are calculated based on the methodology set in the Royal Decree and according to the output of the CRM calibration report. It means that they were calculated:

- On the same 10-years historical availability data as for the CRM calibration report (meaning from 2012 to 2021 included);
- Based on the forced outage rate (including both 'technical' and 'long-lasting' forced outages);
- For all units of the same technology in-the-market during the studied timeframe.

By considering both 'technical' forced outage and 'long-lasting' forced outage, a forced outage rate of 20,5% is determined:

$$FO\ rate = 'Technical'\ FO\ rate + 'long-lasting'\ FO\ rate = \mathbf{4,0} + \mathbf{16,5}\% = \mathbf{20,5}\%\ [\%]$$

Note that the 'technical' forced outages value is in line with the 'unplanned capacity loss factor' calculated by IAEA at world level[52].

However, based on the data observed from historical analysis, some planned outages during winter periods were observed, which is in contradiction with the philosophy of the derating factor, as described in the initial design notes[53]. Therefore, it could be

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[48] https://afcn.fgov.be/fr/dossiers/centrales-nucleaires-en-belgique/actualite/indications-de-defauts-dans-les-cuves-des
[49] https://afcn.fgov.be/fr/dossiers/centrales-nucleaires-en-belgique/actualite/sabotage-de-la-turbine-vapeur-de-doel-4
[50] https://fanc.fgov.be/nl/dossiers/kerncentrales-belgie/actualiteit/betondegradatie-doel-en-tihange
[51] https://afcn.fgov.be/fr/actualites/lafcn-donne-son-feu-vert-au-redemarrage-de-tihange-1-0
[52] https://pris.iaea.org/PRIS/WorldStatistics/WorldTrendinUnplannedCapabilityLossFactor.aspx
[53] https://www.elia.be/-/media/project/elia/elia-site/users-group/ug/tf-crm/2020/crm-updated-design-notes---march-2020---all---clean-version.pdf

considered fair to also consider the planned outage rate. While forced outage rates are assumed to be independent from climatic conditions and therefore calculated on the whole year (which is confirmed by historical data), planned outage is mainly foreseen outside of winter periods. Therefore, this additional indicator is only calculated on winter periods.

$$PO\ rate = \frac{PO\ days\ in\ winter\ 2012 \rightarrow 2021}{Total\ days\ in\ winter\ 2012 \rightarrow 2021} = \mathbf{8,1}\ [\%]$$

Those parameters can be converted in an equivalent availability for the nuclear technology. Based on previous results and considerations, an equivalent forced outage for nuclear between 4% and 28,6% could be considered.

5.2.4 Discussion on the results and additional considerations

The results presented above were calculated on the average over the last 10 years and for all nuclear units.

First, it is important to mention that **Doel 4 and Tihange 3 units are more recent** and hence could experience less outages than older units but one should also take into account the fact that those units would be extended beyond 40 years (as were some of the units considered in the dataset) and that the works associated to future LTO on these units might also lead to either extended planned outage or ‘long-lasting’ forced outage due to the analysis performed or to the critical operations to be performed. As also found in the historical data, ‘long-lasting’ forced outages also happened on those 2 most recent units.

It is also important to note that average values do not include the **discretionary impact that ‘forced long-lasting events’ can have**. When those events happen, their impact is corresponding to the size of the unit. This is different when looking at other types of units where there are more units but also generally of smaller size.

While planned maintenance is usually performed outside of winter and therefore should not be considered based on the Royal Decree methodology, the analysis has demonstrated that **it is not excluded that some nuclear units have to perform maintenances during winter**. Indeed, nuclear units might be subject to other constraints than other thermal units. When there is no view yet on the maintenance works planning (which is the case for a Y-4 auction) and also given the uncertainty on the LTO works that might be required, taking into account the planned maintenance historically observed during winter as part of an equivalent forced outage rate is a way to take that risk into account.

The so-called **‘common mode’ failures** of the units are not explicitly taken into account in the analysis as the values provided only look at averages. Some ‘forced long-lasting’ events can have an impact on more than one nuclear unit. Indeed, given the similar conception of those, any anomaly found in one unit can be also found in another one. This was already the case in Belgium (microflakes, concrete degradation on bunker buildings) but also in France where such events did happen several times. Combined with the discretionary nature of those events, the impact on the contribution of nuclear to adequacy is exacerbated.

In addition, it will be key to take the most up to date information when calculating future availability for the nuclear units. That should include the maintenance planning or works (if known) but also new risks not covered by the present analysis (if they arise in the future).

5.3 Conclusion

Based on the results as summarized on Figure 11, the availability of Belgian nuclear units could be fixed between 71,4% and 96%, depending on the independent and cumulative parameters considered: 'technical' forced outages, 'long-lasting' forced outages and planned outages during winter periods.

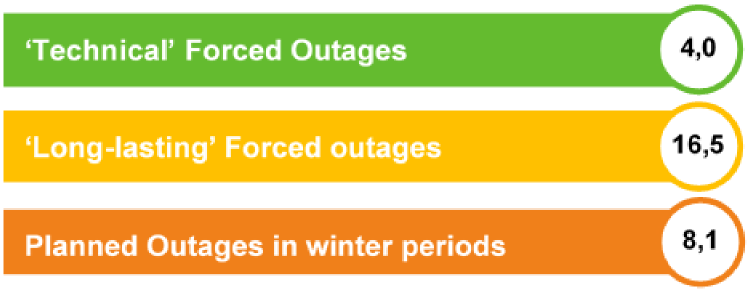


Figure 11: Outage Rates [in %] that could be considered for an equivalent forced outage for nuclear technology

5.4 Details on unit per unit type of historical availability events

The following sections detail the choices made for each past event considered in the dataset. Different periods are considered in the different graphs:

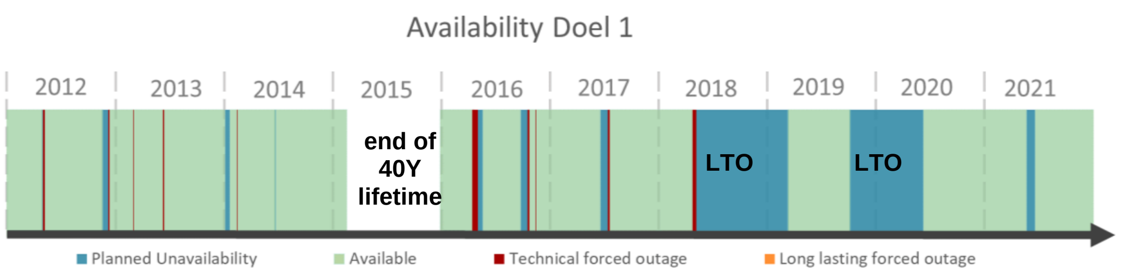
- Periods when the unit is available (in green);
- Periods when the unit is in planned outage (in blue);
- Periods when the unit is in forced outage (in yellow);
- Periods when the unit is in long-lasting forced outage (in red).

The different graphs also indicate the periods when the unit was decoupled from the electricity network (Doel 1), periods when the unit was stopped for LTO works and the details of the issue encountered when a period with long-lasting forced outage is observed.

5.4.1 Doel 1

Remarks regarding Doel 1 availability:

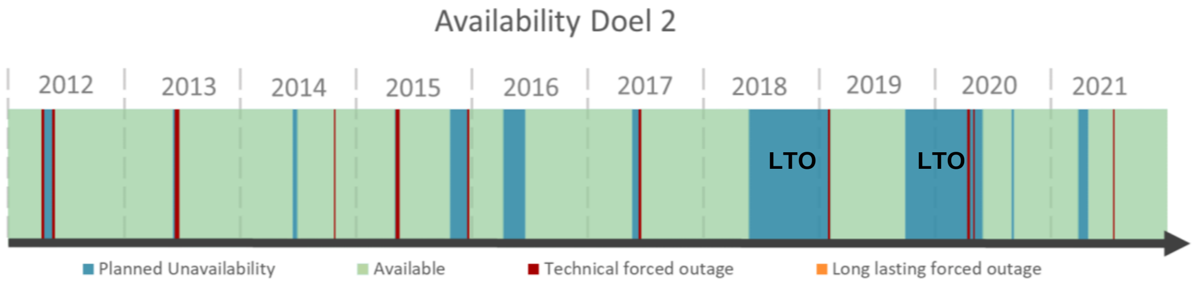
- Doel 1 40-years lifetime ended in February 2015. The unit was then stopped during some months before the political decision was taken to extend its lifetime to 50 years;
- 2 long planned unavailability periods happened from 2018 to Q2 2020 and are linked to the operations and maintenance related to the LTO;
- No long-lasting forced outages were taken into account.



5.4.2 Doel 2

Remarks regarding Doel 2 availability:

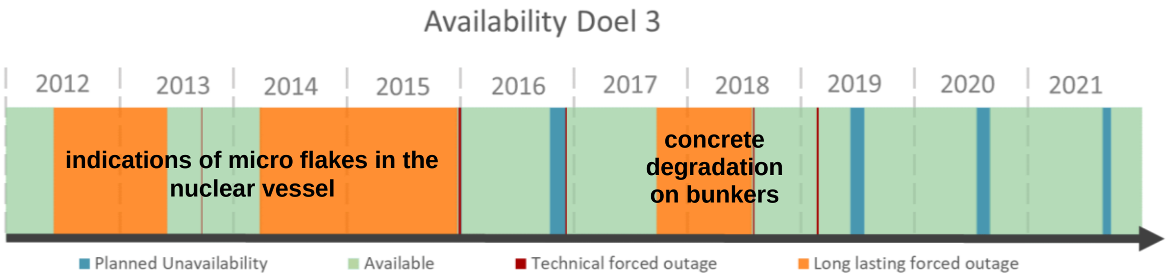
- Doel 1 40-years lifetime was supposed to end in November 2015 but its lifetime was extended to 50 years after political decision;
- 2 long planned unavailability periods happened from 2018 to Q2 2020 and are linked to the operations and maintenance related to the LTO;
- No long-lasting forced outage were taken into account.



5.4.3 Doel 3

Remarks regarding Doel 3 availability:

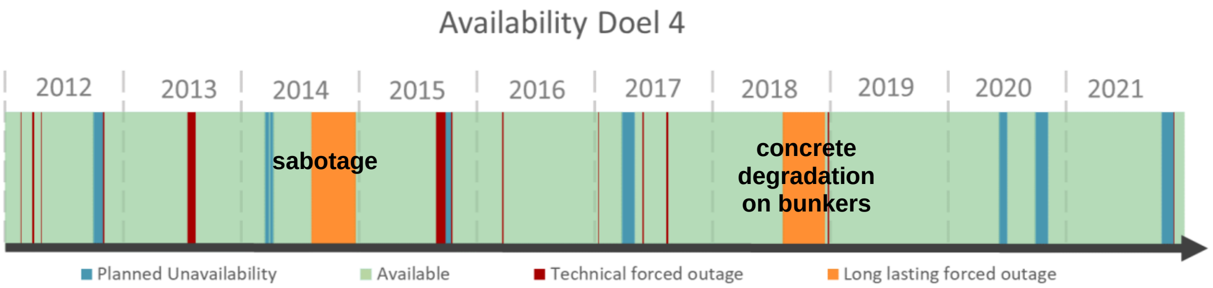
- 2 long-lasting forced outage are considered in 2012-2013 and 2014-2016 related to the indications of microflakes in the nuclear vessel;
- 1 long-lasting forced outage period is considered from 2017 to 2018 related to concrete degradation on bunkers.



5.4.4 Doel 4

Remarks regarding Doel 4 availability:

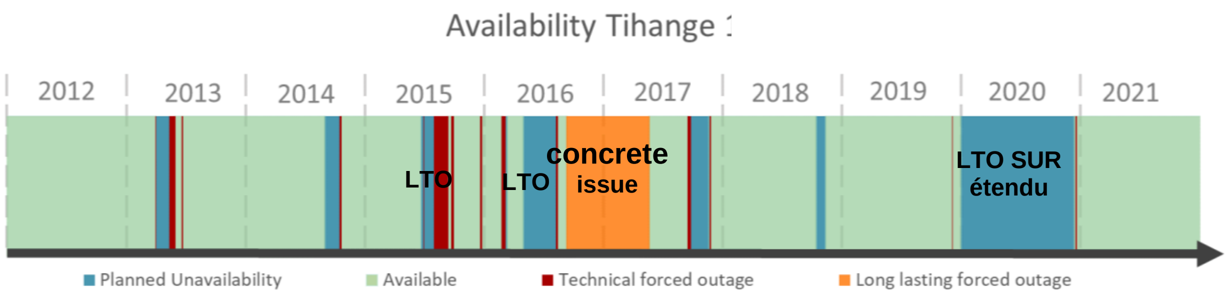
- 1 long-lasting forced outage period is considered in 2014 due to a sabotage;
- 1 long-lasting forced outage period is considered in 2019 related to concrete degradation on bunkers.



5.4.5 Tihange 1

Remarks regarding Tihange 1 availability:

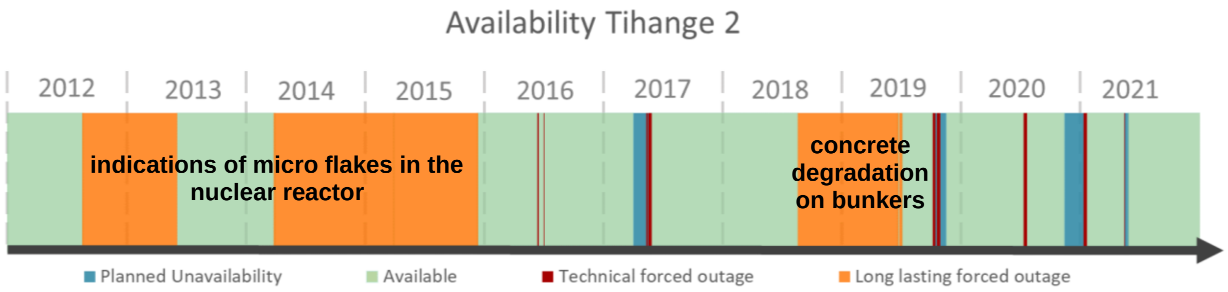
- 1 long-lasting forced outage period is considered in 2016 to 2017 due to a concrete issue on a safety building;
- 3 periods linked to the operations and maintenance related to the LTO are considered, including the last one regarding the commissioning of the “SUR étendu” building.



5.4.6 Tihange 2

Remarks regarding Tihange 2 availability:

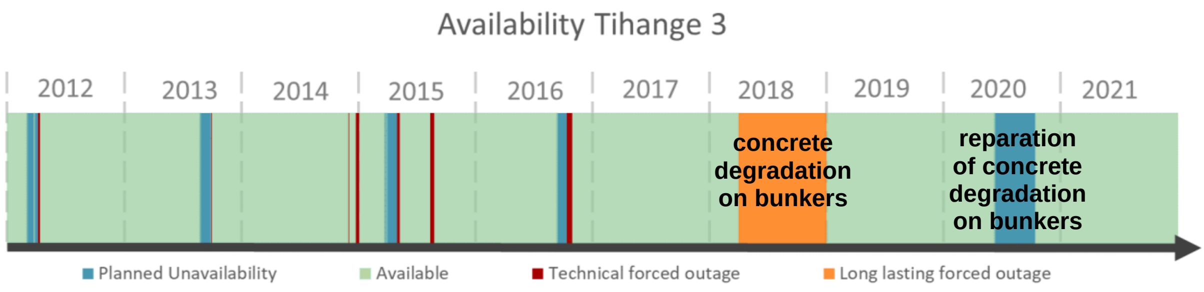
- 2 long-lasting forced outage periods are considered in 2012-2013 and 2014-2016 related to the indications of microflakes in the nuclear vessel;
- 1 long-lasting forced outage period is considered from 2018 to 2019 related to concrete degradation on bunkers.



5.4.7 Tihange 3

Remarks regarding Tihange 3 availability:

- 1 long-lasting forced outage period is considered in 2018 related to concrete degradation on bunkers;
- 1 long period of planned unavailability considered in 2020 related to extra-work required to repair the concrete degradation on bunkers.



6 Appendix: Details on cross-border market capacities

This appendix presents the flow-based domain that will be implemented in the model. The CRM calibration will use an up-to-date flow-based modelling as used in the Adequacy and Flexibility study 2022-32. The parameters of this model are presented in the Excel file (section 4). The presented domain will be complemented with the NTC values taken from the European Resource Adequacy Assessment 2021 (ERAA21) of ENTSO-E for the borders which are not included in the flow-based region.

6.1 The 'mid-term flow-based' modelling framework used in the CRM calibration

Belgium's central location in Europe means that the country's import and export capabilities are defined following the principles of flow-based (FB) capacity calculation and capacity allocation within market coupling, as introduced by the European guideline on Capacity Allocation & Congestion Management (CACM), hereafter "FB CACM"[54]. In FB CACM, Belgium's net position is linked to the net position of the other countries in the Core region and to the flow-based domain defining the possibilities for exchanges of energy between these countries. Only by replicating the functioning of the electricity market, adequacy and economic indicators can accurately be calculated. The flow-based method makes it possible to properly take into account interactions between market outcomes and the transmission grid. In the market simulations performed for this study, the commercial exchange capacities are modelled in three different ways:

- **For exchanges** between two countries **outside the Core region** and**,** fixed bilateral exchange capacities (also called NTC – Net Transfer Capacities) as described in Section 6.2 are applied.
- **For exchanges between the Core region and bidding zones external to Core**, fixed bilateral exchange capacities are used. A flow-based modelling (also known as 'Advanced Hybrid Coupling'- AHC is applied as from year 2025. More information can be found in Section 6.3.
- **For exchanges** inside the **Core region,** the flow-based methodology as described in Section 6.4 is applied;

[54] https://www.entsoe.eu/network_codes/cacm/

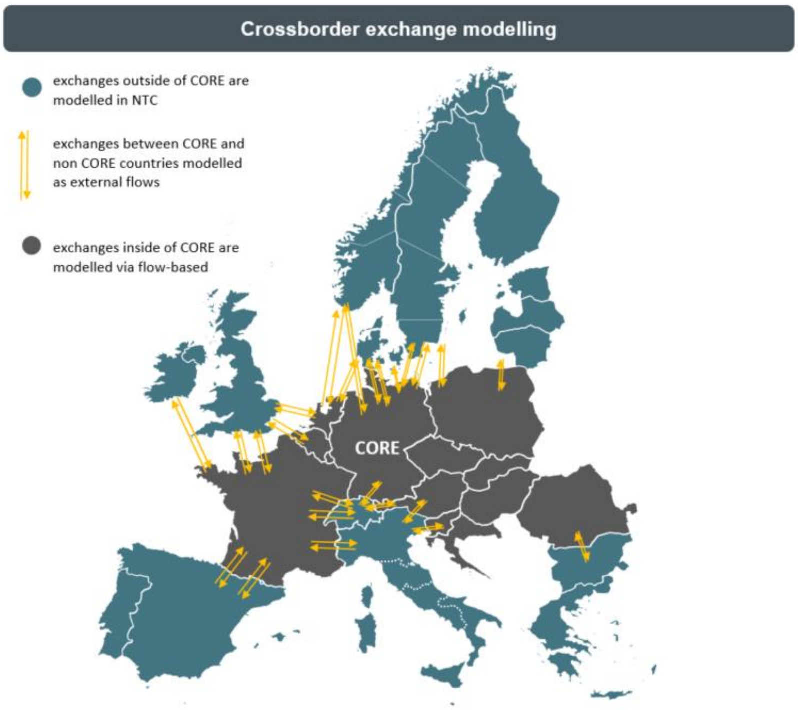


Figure 12: Overview of cross-border exchange modelling

6.2 NTC modelling between two non-Core countries

The commercial exchange capacities between non-Core countries are modelled using 'Net Transfer Capacities' (NTC), corresponding to fixed maximal commercial exchange capacities between two bidding zones. The values are taken from the most recent dataset available at ENTSO-E and from bilateral and multilateral contacts with TSOs and are in line with those used for studies conducted within ENTSO-E (latest ERAA study).

6.3 External flows: exchanges between Core and non-Core countries

External flows are flows in the Core grid which are induced by exchanges through bidding zone borders that do not belong to the Core region. Currently e.g. NEMOLink® is in this situation.

External flows can be linked to the flow-based region in one of two ways: standard hybrid coupling (SHC) or advanced hybrid coupling (AHC). In the former, a capacity margin is reserved on all CNEC's to accommodate for the external flows before flow-based market coupling. In the latter that will be used at the time horizon of the study, the external flow is part of the flow-based optimisation variables. On a high level, SHC grants priority access to these external flows into the meshed AC transmission grid of the Core CCR by means of the above mentioned reserved capacity margin. In the AHC however these external power flows are threated in equal basis to the power flows created by to electricity commercial exchanges between Core bidding zones.

This results in a higher complexity of the flow-based domain calculation as any external border & link considered in AHC will add an extra dimension to the domains considered. AHC introduces a major conceptual and methodological change, which can be understood by its visual impact on the projected domains. A 2D flow-based domain projection will look larger in AHC compared its SHC counterpart, since in SHC the impact of the external exchanges as an external flow through each CNEC is reserved from the capacity margin of the CNEC (hence the RAM of the CNEC is reduced to account for this external flow) and hence not considered explicitly as part of the flow-based domain capacity.

6.4 Flow-based for Core countries

Flow-based capacity calculation is a complex process involving many parameters. Multiple approaches are possible when building market models where market exchanges adhere to the rules depicted in a flow-based coupled market. For short-term forecasts and analyses, a framework using the flow-based domains calculated within the SPAIC process was developed[55]. However, this framework relies heavily on historical data, and becomes more complex and less accurate when multiple parameters and inputs are expected to change between the historical flow-based data preparation and the targeted time horizon. It is also not possible to take major evolutions into account (such as AHC, the extension of the capacity calculation region or the minRAM requirements) within this approach. Elia has therefore developed a flow-based framework which does not rely on historical domains, but instead aims to mimic the operational flow-based capacity calculation workflow, for which the required inputs are forecasted for the targeted time horizon. One of the key advantages of using such a method is that it enables modelling several planned evolutions such as AHC and the impact of minRAM requirements on the domains.

6.5 Flow-based domain creation process

The flow-based framework developed for this study aims at mimicking the currently applied operational framework as well as integrating the future foreseen flow-based evolutions. This process is illustrated in Figure 13 and further detailed in the following paragraphs.

[55] Framework of the Standard Process to Assess the Impact of significant Changes (SPAIC) within the CWE flow-based consultation group towards market parties.

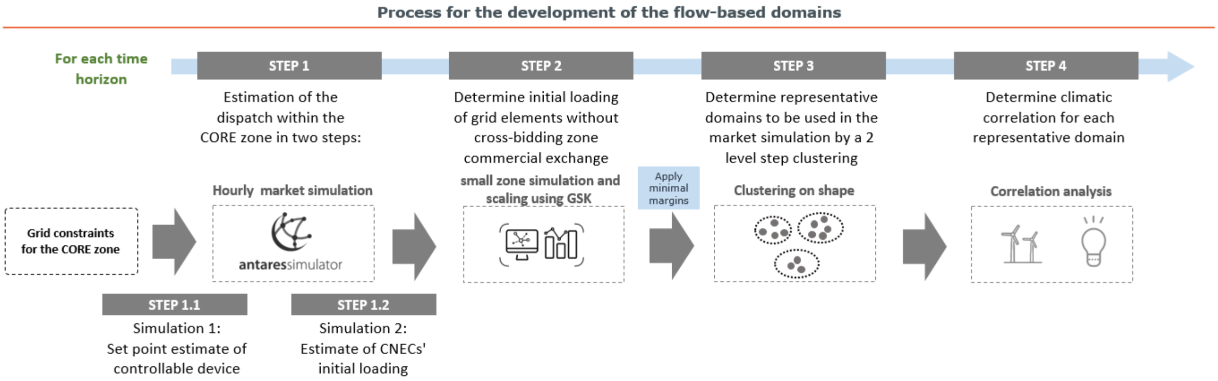


Figure 13: Process for the development of the flow-based domains

STEP 1: Estimation of the dispatch

The first simulation called 'flow estimation' aims to determine the set points of the different controllable devices, i.e. HVDCs and PSTs. This first run is crucial for the grid feasibility.

The second run or 'base case simulation' mimics the capacity allocation and congestion management (CACM) capacity calculation (CC) process and allows for a good estimation of the pre-loading on CNECs. Once fully set up, the flow-based framework performs an initial simulation to determine the initial loading of each CNEC. In this simulation, around 1/2 of the PST tap ranges in Belgium and about 1/3 for other countries can be used to optimize initial flows compared to their predefined set points in order to maximize the welfare of the system. The flows from this simulation determine the 'Reference Flows'.

STEP 2: Initial loading of grid elements

In a next step, combining geographical information on the location of load and generation within CORE with the hourly market dispatch from STEP 1, the loadings of grid elements associated with the hourly commercial exchanges resulting from the market simulation in STEP 1 can be determined for each hour. For determining the market domain, initial loadings of grid elements in the absence of commercial exchanges are required. Using the bidding-zone GSK, the net position of each of the bidding zones is scaled to zero. Hereby, commercial exchanges between bidding zones are cancelled, and the remaining flow on grid elements equals the initial loadings (loop flows and potentially some internal flows). The process used to scale the net positions of all bidding zones to zero is the same as the one used in flow-based operations today.

Such initial loadings could potentially pre-use a significant portion of the physical capacity of grid elements, and thereby restrict market operations. As from 1 January 2020, the 'Clean Energy Package' is applicable. In this regulation, specific requirements related to the availability of transmission capacity for market exchanges are introduced. To model the application of those rules for future time horizons, virtual minimal margins are applied to each grid element for determining the final hourly flow-based domains.

STEP 3

As the market simulation performed in STEP 1 creates an estimation of the dispatch and corresponding initial loadings within CORE for each hour of the simulated year, this would result in 8760 different flow-based domains. For the present study, it was chosen to limit the amount of flow-based domains for each time horizon in order to obtain feasible computation times by reducing the complexity of the simulations.

STEP 3.1: Smart slicing

Enumerating full-dimensional polytopes is impossible with the current domain dimensionality (12 CORE biding zones + ALEGrO + AHC dimensions). Nine dimensions (9D) are deemed most relevant to Belgian security of supply (CWE + ALEGrO + interconnectors BE-UK, NL-UK and FR-UK). The positions of the other dimensions are considered by the procedure of 'smart slicing' and thus fixed for each hour to the market simulation results obtained in STEP 2. Through 'smart slicing', the full dimensional polytope is then reduced to a 9D polytope describing the feasible net positions of these nine most relevant dimensions for Belgium. Vertices enumeration is hence performed by considering these nine-dimensional polytopes at each hour.

STEP 3.2: Clustering of domains

Applying a clustering algorithm requires a metric that can be used to assess the similarity of domains. The clustering of the 8,760 domains is based on their geometrical shape by means of comparing the Euclidian distance between vertices. A pre-cluster data split is applied to reduce cluster group size and hence computational complexity whilst respecting time-related trends. In this split summer and winter domains are separated, weekends and weekday are separated, and within the weekdays the peak & off peak hours are separated as well. This results in the creation of 6 groups to be clustered individually. Next, the number of centroids to retain must be defined. For weekends one centroid was calculated to represent the entire group, whereas for weekdays, per group, 2 clusters are created, each with its own centroid (see Figure 14). The clustering is performed by means of a k-medoid algorithm. Here the centroids are elements which are part of the initial domains, and therefore have physical meaning. This process is performed in two steps in order to be able to reduce the set and ultimately find the representative centroids.

The level 1 clustering gives a first set of medoids that will be further refined in the level 2 in order to reach the targeted number of clusters.

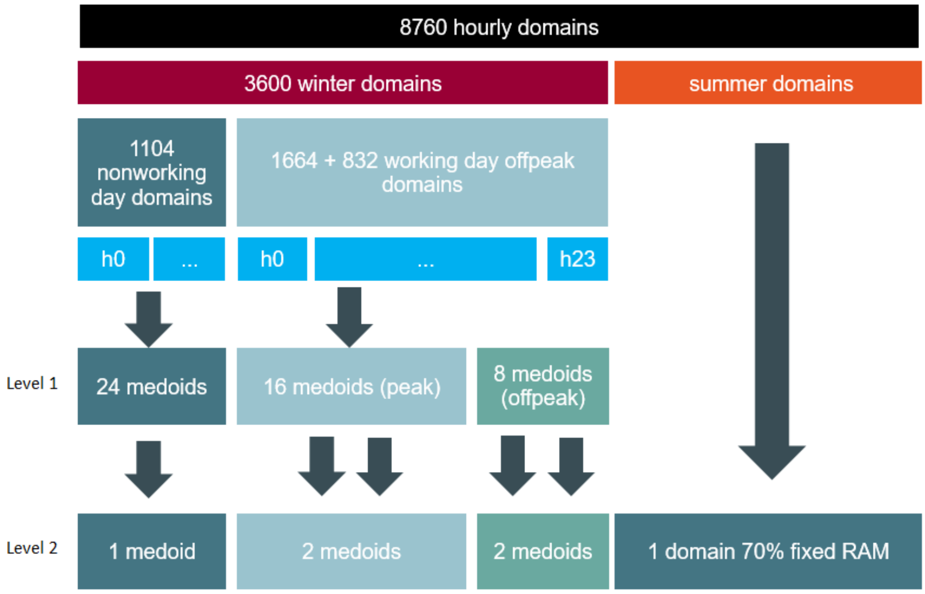


Figure 14: Clustering of domains

STEP 3.3: Resizing and approximating the domains for computational efficiency

The domains are subsequently restored back to their full dimensions of 12 CORE biding zones + ALEGrO + AHC dimensions prior to plugging them back into the ANTARES model. In general, the number of CNECs in the framework's domains is too large to be of practical use in market simulations.

A flow-based domain is defined by a certain number of inequality constraints representing the limits of critical network elements at a given time. Keeping the complexity at an acceptable level is key to successfully carry out the simulations. The chosen way forward is to use a simplification algorithm based on the Manhattan distance of two hyperplanes. This step allows to define the smallest set of CNECs that can be used to describe the entire domain, without any loss of quality or representativeness. Finally such smallest set is the one kept as the PTDF-RAM linear constraints to be set into the model.

STEP 4: Incorporating multiple flow-based domains into the adequacy assessment

The 'Monte Carlo' approach used in this study generates possible future states, called 'Monte Carlo' years. The method used for relating typical days to the climatic conditions as they occur in the Monte Carlo years was developed by the French TSO RTE (see reference documents[56] [57]), and is also implemented in RTE's adequacy study (*Bilan Prévisionnel* since 2017) as well as in the *Pentalateral Energy Forum - GAA 2020 Report* (PLEF 2020) and the latest ERAA 2021 report.

This method can be understood as follows. The k-medoid algorithm not only selects the representative domains for each of the clusters, but also identifies for each day the cluster to which it belongs. Thus, for the climatic variables in scope, thresholds can be defined (typically at the 33rd and 66th percentiles) which lead to the creation of climatic groups. As such, it is possible to identify, for every day, the climatic group to which it belongs. By counting the amount of times a domain appears in a specific climatic group, it is possible to define a probability matrix. This matrix represents the probability of being in a given cluster of domains under certain climatic conditions. Using the climatic conditions encountered at a given hour in the model we can then map the clusters back to the hours in the model. It is this interpretation that is used when mapping the typical days onto the 'Monte Carlo' years.

This kind of systematic approach makes it possible to link specific combinations of climatic conditions expected in future target years, e.g. high/low wind infeed in CWE (Germany, France, etc...) high/low temperature and demand in France and Belgium, with the representative domains for these conditions.

For each time horizon, a correlation analysis between the domain clusters and several input parameters was applied in order to link a given market situation to the flow-based domain to be applied. This analysis resulted in the selection of German wind infeed and French consumption as the most relevant parameters in determining the selection of the domain. Therefore, in the final simulations the hourly choice of the applied domain is based on this correlation with said external parameters. The probability of finding a domain given a certain set of climatic conditions can be derived from the cluster process' results as explained above.

[56] https://antares-simulator.org/media/files/page/7NY5W-171024-Rte-Typical-Flow-Based-Days-Selection-1.pdf

[57] https://antares-simulator.org/media/files/page/ZHX0N-171024-Rte-Modelling-of-Flow-Based-Domains-in-Antares-for-Adequacy-Studies.pdf