Commissie voor de Regulering
van de Elektriciteit en het Gas

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Study

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Analysis by the CREG of the Elia study 'Adequacy and flexibility study for Belgium 2020 - 2030'

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CONTENT

EXECUTIVE SUMMARY (NL)

Elia heeft haar studie over de bevoorradingszekerheid en flexibiliteit 2020-2030 gepubliceerd op 28 juni 2019. Elia heeft een aantal belangrijke verbeteringen aangebracht ten opzichte van eerdere studies, zoals het in rekening brengen van de flow-based market coupling voor wat betreft de importcapaciteit en de economische leefbaarheidstest. Desalniettemin meent de CREG dat, op basis van de opmerkingen die in deze studie worden toegelicht, haar voorstellen kunnen leiden tot een daling van het potentieel capaciteitstekort.

De studie van Elia kan dan ook nog verbeterd en verfijnd worden door de geanalyseerde elementen te integreren die hierna door de CREG worden voorgesteld. De CREG geeft in dit document aan waarom en hoe deze elementen in rekening kunnen worden gebracht. Op die manier kan de studie zoveel mogelijk in lijn gebracht worden met het Europese Clean Energy Package. Tevens geeft de CREG ook haar standpunt over de formele procedures inzake consultatie die zouden gevolgd worden.

1. Er is sprake van een door Elia gesimuleerd tekort van 3,9 GW, terwijl het basisscenario resulteert in een significant lager tekort in 2025

Elia stelt in haar kernboodschap dat er een tekort van 3,9 GW te verwachten is tegen de winter van 2025-2026, na de volledige uitfasering van de nucleaire capaciteit. Dit resultaat is niet gebaseerd op het basisscenario, maar op een sensitiviteitsanalyse ‘low probability – high impact’ waarbij Frankrijk onverwacht 3,6 GW nucleair verliest. Hierdoor zou Frankrijk haar bevoorradingszekerheid niet kunnen garanderen, ondanks een CRM in Frankrijk.

Het basisscenario toont een tekort van 2,4 GW indien de bestaande thermische capaciteit in het systeem kan worden gehouden. Het is belangrijk om op te merken dat in het basisscenario, naast het in rekening brengen van verschillende historische klimaatjaren[1], dus ook extreme gebeurtenissen zoals lange periodes met weinig wind en koudegolven, ook de recent verminderde beschikbaarheid van de kerncentrales werd gesimuleerd (33% tot 50% van de nucleaire capaciteit onbeschikbaar).

Verder houdt de studie geen rekening met de aanwezigheid van de bestaande gascentrale in Vilvoorde (265 MW), waardoor het tekort daalt met minstens 0.2 GW.

2. Het door Elia gesimuleerde tekort vermindert in 2028 met 1,4 GW naar 0.8 GW (tegenover 2025)

Indien alle bestaande capaciteit behouden wordt, vermindert het gesimuleerde tekort tot 0.8 GW in 2028.

3. Het door Elia gesimuleerde tekort is in 2025-2026 gemiddeld gedurende 5-7 uren nodig om aan de criteria van de bevoorradingszekerheid te voldoen

Uit de resultaten van het basisscenario blijkt dat het gesimuleerde tekort gemiddeld 5-7 uren nodig is om te voldoen aan het criterium van gemiddeld 3u LoLE.

[1] Zie appendix E.2. van de Elia studie : Sets van verschillende meteorologische omstandigheden die een impact hebben op de hernieuwbare elektriciteitsproductie en het elektriciteitsverbruik. Dergelijke omstandigheden (wind, zonnestraling, temperatuur en neerslag) zijn geografisch en tijdsgecorreleerd voor een bepaalde regio en zelfs tussen landen.

4. Verbeteren van de methodologie om de winstgevendheid van bestaande en nieuwe capaciteit te evalueren

Elia simuleert de winstgevendheid voor drie jaren: 2020, 2023, 2025. Dit gebeurt op basis van een model.

Voor 2020 zijn er echter ook al marktprijzen beschikbaar, zodat de door Elia gemodelleerde inkomsten geverifieerd kunnen worden. Hieruit blijkt dat reële marktinkomsten gemiddeld twee keer hoger liggen dan de inkomsten die Elia gebruikt om de economische leefbaarheid van bestaande en nieuwe capaciteit te evalueren. Het niet gebruiken van de bestaande marktprijzen leidt tot een onderschatting en een vertekend beeld. De door Elia gesimuleerde resultaten zouden ook verbeterd moeten worden.

Voor de economische leefbaarheidstest gebruikt Elia de mediaan (P50) van de inkomsten uit de probabilistische analyse om de inframarginale rente te berekenen. Om de economische waarde van de capaciteit te beoordelen, moeten de operatoren echter hun assets financieel afdekken (*hedging of assets*). De afdekking gebeurt op de forwardmarkt. Forwardprijzen weerspiegelen niet de verwachte mediane spotprijs (P50), maar wel de verwachte spotprijzen in alle mogelijke scenario's, gewogen op basis van hun respectievelijke kansen. Dit komt neer op het gebruik van het <u>gemiddelde</u> van de gesimuleerde inframarginale rentes en zou ertoe leiden dat veel meer bestaande capaciteit in de markt blijft en dat veel meer nieuwe capaciteit op de markt komt.

De CREG stelt voor deze aangepaste evaluatie te gebruiken met het huidig prijsplafond en een hoger prijsplafond, waarbij met een hoger prijsplafond het vraagbeheer dat toegevoegd wordt op haar beurt gaandeweg een hogere marginale kost toegewezen krijgt.

Wat betreft WKKs, zou Elia alle inkomsten in rekening moeten brengen, met inbegrip van de inkomsten uit het bestaande ondersteuningsmechanisme (WWK- of groenestroomcertificaten), dat net ontwikkeld is om WKKs rendabel te maken. Bovendien blijkt uit een CREG-studie van 2016[2] dat nieuwe decentrale productiecapaciteit die na de meter kan geplaatst worden, zoals WKK's en gasmotoren, wel degelijk rendabel is. De impact van het hebben van productiecapaciteit na de meter zou meegerekend moeten worden door Elia.

De CREG stelt voor rekening te houden met het invoeren van een 'shortage pricing function' die de rendabiliteit van de bestaande capaciteit nog gevoelig zou verbeteren.

5. Alle beschikbare balanceringsreserves in België en het buitenland zouden in rekening moeten worden gebracht

De toetsing van de criteria inzake bevoorradingszekerheid dient gesimuleerd te worden op basis van de situatie in reële tijd. De netbeheerder moet immers alle mogelijke middelen inzetten om een onvrijwillige afschakeling in reële tijd te vermijden, inclusief het gebruik van de balanceringsreserves die op dat moment niet nodig zijn voor de balancing, en vervolgens gebruikt kunnen worden voor de bevoorradingszekerheid. Een bevoorradingszekerheidsprobleem stelt zich pas als de studie zou uitwijzen dat er gemiddeld meer dan 3 uur (LOLE-criterium) overgegaan moet worden tot onvrijwillige afschakeling. Bovendien kunnen ook buitenlandse reserves de Belgische bevoorradingszekerheid verbeteren. De impact van het gebruik van alle beschikbare reserves op de niet-geleverde energie zou op een optimale manier gesimuleerd moeten worden.

[2] See CREG-study 1583 in Dutch: https://www.creg.be/sites/default/files/assets/Publications/Studies/F1583NL.pdf
See CREG-study 1583 in French: https://www.creg.be/sites/default/files/assets/Publications/Studies/F1583FR.pdf

6. Bijdrage door het buitenland – rekening houden met marktreactie in het buitenland

De importcapaciteit van België loopt binnen enkele jaren op tot 7.500 MW. Uit de simulaties blijkt dat er in 2025 verwacht wordt dat gemiddeld minder dan 2.500 MW ingevoerd wordt, wanneer België een probleem zou hebben met bevoorradingszekerheid. Tijdens momenten van schaarste is er dus nog importcapaciteit beschikbaar. Het door Elia ingeschat tekort in België kan dan ook (deels) geleverd worden door het buitenland, indien er in dat land geen tekort is.

Omdat er op momenten van schaarste nog importcapaciteit beschikbaar is, zullen andere landen zoals Nederland, Duitsland, Frankrijk en UK vaak dezelfde hoge prijzen noteren als België indien België een elektriciteitstekort zou hebben. Deze prijzen kunnen oplopen tot 10.000 €/MWh en meer. Indien dit effectief gebeurt, zal de markt reageren met een groter aanbod van capaciteit in België (zie ook de voorbije winter waarbij 1.200 MW capaciteit voor een deel uitzonderlijk werd toegevoegd op enkele maanden tijd mede dank zij de genomen maatregelen door de overheid), maar ook in die andere landen. Elia houdt, weliswaar op een manier die moet verbeterd worden (zie boven), rekening met een dergelijke marktreactie in België, waarbij 1.000 MW extra wordt toegevoegd, maar met grotendeels beperkte beschikbaarheid. Bovendien sluit Elia in de andere landen een marktreactie (en dus bijkomende capaciteit) uit, ook al zullen de prijzen ook in die landen oplopen tot 10.000 €/MWh en meer. De aangepaste economische leefbaarheidstest moet dan ook uitgevoerd worden voor de andere landen.

Elia rekent in een sensitiviteitsanalyse met het niet uit de markt nemen van gasgestookte capaciteit, waardoor het tekort voor België daalt met 0,7 GW. Echter, er is ondertussen zelfs sprake van een terugkeer van gasgestookte capaciteit naar de markt en dit zou versterkt kunnen worden door de versnelde kolenuitstap in Duitsland. Het behoud en terugkeer van gasgestookte productiecapaciteit zou in het basisscenario opgenomen moeten worden, via de economische leefbaarheidstest.

7. De winterreserves in Duitsland zouden in rekening moeten worden gebracht

Duitsland heeft momenteel 6,6 GW winterreserves. De Duitse regulator voorziet een stijging tegen 2022-2023 tot 10,6 GW. Deze reserves dienen voornamelijk om het binnenlandse elektriciteitsnet te stabiliseren wanneer er veel windproductie in het noorden is die moet getransporteerd worden naar het zuiden. Tijdens periodes van veel wind worden er geen capaciteitstekorten verwacht.

Tijdens periodes van weinig wind zijn deze reserves dan ook grotendeels beschikbaar, ook om eventueel de bevoorradingszekerheid van België te ondersteunen. Dit zou in de studie in rekening moeten worden gebracht. Er dient wel opgemerkt te worden dat, opdat dergelijke capaciteit ter beschikking kan worden gesteld, er tussen de lidstaten overeenkomsten dienen gesloten te worden.

Conclusie

De Elia-studie over de bevoorradingszekerheid in België voor 2020-2030 kan op een aantal belangrijke punten verbeterd worden. Met die verbeteringen zou de studie meer in lijn gebracht worden met de bestaande Europese wetgeving. Bepaalde hypotheses van de voorliggende studie leiden tot een overschatting van de noden.

Gezien de impact van de kost van een CRM op de factuur van de consumenten[3], vindt de CREG dat het belangrijk is om de capaciteitsnoden op een meer optimale en preciezere manier te bepalen, met inachtneming van de bevoorradingszekerheid en het vermijden van en al te grote overschatting van het nodige volume. De CREG suggereert om een bijkomende analyse te vragen aan Elia waarbij de verbeteringen opgesomd in dit document geïntegreerd worden, vooraleer te concluderen hoe groot een eventueel elektriciteitstekort is.

Teneinde zo efficiënt mogelijk tegemoet te komen aan de bekommernissen van de bevoorradingszekerheid, kan het best naast de uitwerking van een marktbrede CRM, ook de optie van een, eventueel aangepaste, Strategische Reserve open worden gehouden. Het Clean Energy Package voorziet immers een hiërarchie waarbij eerst onderzocht moet worden of een Strategische Reserve een eventueel elektriciteitstekort kan oplossen.

[3] Zie studie PwC : https://economie.fgov.be/sites/default/files/Files/Energy/Rapport-Bepaling-van-het-mechanisme-voor-de-vergoeding-van-capaciteit-voor-Belgie-en-de-voorbereiding-van-het-wettelijk-kader.pdf

EXECUTIVE SUMMARY (FR)

Le 28 juin 2019, Elia a publié son étude 2020-2030 sur la sécurité d'approvisionnement et la flexibilité. Elia a apporté plusieurs modifications majeures par rapport aux précédentes études, comme la prise en compte du couplage des marchés fondé sur les flux en ce qui concerne la capacité d'importation et le test de viabilité économique. Sur la base des remarques exposées dans cette étude, la CREG estime toutefois que ses propositions pourront réduire le déficit potentiel de capacité.

L'étude d'Elia pourrait donc être améliorée et affinée en intégrant les éléments analysés que la CREG présente ci-après. Dans ce document, la CREG indique pourquoi et comment ces éléments peuvent être pris en compte afin d'aligner le plus possible l'étude sur le *Clean Energy Package* européen. Par ailleurs, la CREG communique son point de vue sur les procédures formelles de consultation qui devraient être suivies.

1. Il est question d'un déficit simulé par Elia de 3,9 GW ; alors que le scénario de base résulte en un déficit bien moindre en 2025

Dans son message clé, Elia indique qu'un déficit de 3,9 GW est attendu d'ici l'hiver 2025-2026, après la sortie complète de la capacité nucléaire. Ce résultat ne se fonde pas sur le scénario de base mais sur une analyse de sensibilité *low probability – high impact*, où la France perd de manière inattendue 3,6 GW de capacité nucléaire. La France ne pourrait dès lors plus garantir sa sécurité d'approvisionnement, malgré un CRM en France.

Le scénario de base montre un déficit de 2,4 GW si la capacité thermique existante peut être maintenue dans le système. Il est important de souligner que plusieurs années climatiques historiques[4], comportant aussi des événements extrêmes tels que de longues périodes avec peu de vent et des vagues de froid, ont également été prises en compte dans le scénario de base ; la diminution récente de la disponibilité des centrales nucléaires (33 à 50 % de la capacité nucléaire indisponible) y a également été simulée.

En outre, l'étude ne tient pas compte de la centrale à gaz existante à Vilvorde (265 MW), si bien que le déficit diminue d'au moins 0,2 GW.

2. En 2028, le déficit simulé par Elia diminue de 1,4 GW par rapport à 2025 pour s'établir à 0,8 GW.

Si toute la capacité existante est maintenue, le déficit simulé diminue à 0,8 GW en 2028.

3. En 2025-2026, le déficit simulé par Elia n'est nécessaire que durant 5 à 7 heures en moyenne pour répondre aux critères de la sécurité d'approvisionnement.

Il ressort du scénario de base que le déficit simulé n'est nécessaire que durant 5-7 heures en moyenne pour répondre au critère de 3 heures de LoLE en moyenne.

[4] Voir appendix E.2. de l'étude d'Elia. Ensembles de diverses conditions météorologiques qui ont un impact sur la production de l'électricité renouvelable et la consommation d'électricité. De telles conditions (vent rayonnement solaire, température et précipitation) sont corrélées géographiquement et dans le temps pour une région donnée et même entre pays.

4. Amélioration de la méthodologie visant à évaluer la rentabilité de la capacité nouvelle et existante

Elia établit une simulation de la rentabilité pour trois années : 2020, 2023 et 2025. Pour ce faire, elle se fonde sur un modèle.

Des prix de marché sont toutefois déjà disponibles pour 2020, si bien que les revenus modélisés par Elia peuvent être vérifiés. Il en ressort que les revenus réels du marché sont en moyenne deux fois plus élevés que les revenus estimés par Elia pour évaluer la viabilité économique de la capacité existante ainsi que de la nouvelle capacité. Le fait de ne pas utiliser les prix du marché existants entraîne une sous-estimation et donne une image faussée. Les résultats simulés par Elia devraient également être améliorés.

Pour le test de viabilité économique, Elia utilise la rente inframarginale médiane (P50) de l'analyse probabiliste. Toutefois, pour évaluer la valeur économique de la capacité, les opérateurs doivent couvrir leurs *assets*. La couverture se fait sur le marché *forward*. Les prix *forward* ne reflètent pas les prix spot (P50) médian attendus mais les prix spot attendus dans tous les scénarios possibles, pondérés en fonction de leurs probabilités respectives. Cela revient à utiliser la moyenne simulée inframarginale, avec pour conséquence que la capacité existante resterait en quantité bien plus importante sur le marché et que beaucoup plus de nouvelle capacité arriverait sur le marché.

La CREG propose d'utiliser cette évaluation adaptée en appliquant le plafond des prix actuel et un plafond de prix plus élevé ; avec un plafond des prix plus élevé, la gestion de la demande qui s'ajoute se voit progressivement attribuer à son tour un coût marginal plus élevé.

S'agissant des centrales de cogénération, Elia devrait prendre en compte tous les revenus, y compris les revenus du mécanisme de soutien existant (cogénération ou certificats verts), qui a justement été développé pour rendre ces unités rentables. En outre, il ressort d'une étude de la CREG de 2016[5] que la nouvelle capacité de production décentralisée, qui peut être placée après le compteur, comme la cogénération et les moteurs à gaz, est plutôt rentable. L'impact de la capacité de production placée après le compteur devrait être comptabilisée par Elia.

La CREG propose de tenir compte de l'introduction d'une *shortage pricing function* qui améliorerait encore sensiblement la rentabilité de la capacité existante.

5. Toutes les réserves d'équilibrage disponibles en Belgique et à l'étranger devraient être prises en compte

L'examen des critères de sécurité d'approvisionnement doit être simulé sur la base de la situation en temps réel. Le gestionnaire de réseau doit en effet mettre en œuvre tous les moyens possibles pour éviter un délestage involontaire en temps réel, y compris l'utilisation des réserves d'équilibrage qui ne sont pas nécessaires à ce moment-là pour l'équilibrage et qui peuvent alors être utilisées pour la sécurité d'approvisionnement. Un problème de sécurité d'approvisionnement ne se poserait que si l'étude démontrait qu'il faudrait recourir au délestage involontaire pendant plus de trois heures en moyenne (critère LOLE). En outre, des réserves étrangères peuvent également améliorer la sécurité d'approvisionnement en Belgique. L'impact de l'utilisation de toutes les réserves disponibles sur l'énergie non fournie devrait être simulée de manière optimale.

[5] Voir étude 1583 de la CREG en néerlandais : https://www.creg.be/sites/default/files/assets/Publications/Studies/F1583NL.pdf
Voir étude 1583 de la CREG en français : https://www.creg.be/sites/default/files/assets/Publications/Studies/F1583FR.pdf

6. Contribution de l’étranger - prise en compte de la réaction du marché à l’étranger

Dans quelques années, la capacité d’importation de la Belgique augmentera à 7500 MW. Il ressort des simulations qu’en 2025, on s’attend à pouvoir importer en moyenne moins de 2500 MW dans le cas où la Belgique rencontrerait un problème de sécurité d’approvisionnement. De la capacité d’importation reste donc disponible durant les moments de pénurie. Le déficit estimé par Elia en Belgique peut donc être fourni (partiellement) par l’étranger, si le pays en question ne connaît pas de pénurie.

Comme de la capacité d'importation est encore disponible durant les moments de pénurie, d’autres pays tels que les Pays-Bas, l’Allemagne, la France et le Royaume-Uni enregistreront souvent des prix élevés similaires à ceux de la Belgique, dans le cas où cette dernière connaîtrait un déficit en électricité. Ces prix pourraient s’élever à 10 000 €/MWh, voire plus. Si cette situation devait effectivement se produire, le marché réagira en augmentant l’offre de capacité en Belgique (comme ce fut le cas l’hiver passé, où une capacité de 1200 MW a été ajoutée, pour une part à titre exceptionnel, en l’espace de quelques mois, grâce aux mesures prises par les autorités), mais aussi dans ces autres pays. Elia tient compte, certes d’une manière qui a besoin d’être améliorée (voir ci-dessus), d’une telle réaction du marché en Belgique : 1000 MW supplémentaires sont ajoutés mais la disponibilité est en grande partie limitée. En outre, Elia exclut une réaction du marché (et donc de la capacité supplémentaire) dans les autres pays, même si ces pays voient également leurs prix augmenter jusqu’à 10.000 €/MWh et plus. Le test de viabilité économique adapté doit donc être réalisé pour les autres pays.

Dans une analyse de sensibilité, Elia tient compte du maintien sur le marché d’une capacité de production au gaz, ce qui fait diminuer de 0,7 GW le déficit pour la Belgique. Cependant, entre-temps, il est même question d’un retour de capacité de production au gaz sur le marché, un phénomène qui pourrait se renforcer avec la sortie accélérée du charbon en Allemagne. Le maintien et le retour d’une capacité de production au gaz devrait être intégré dans le scénario de base via le test de viabilité économique.

7. Les réserves hivernales en Allemagne devraient être prises en compte

L’Allemagne dispose actuellement de 6,6 GW de réserves hivernales. Le régulateur allemand prévoit une augmentation à 10,6 GW d’ici 2022-2023. Ces réserves servent principalement à stabiliser le réseau électrique intérieur lorsque la production éolienne est importante dans le nord et doit être transportée vers le sud. Durant les périodes de grand vent, aucun déficit de capacité n’est attendu.

Pendant les périodes de vent faible, ces réserves sont dès lors disponibles en grande partie, éventuellement afin de soutenir également la sécurité d’approvisionnement de la Belgique. Cette situation devrait être prise en compte dans l’étude. Il convient toutefois de souligner que la mise à disposition d’une telle capacité exige que des accords soient conclus entre les Etats membres.

Conclusion

L’étude d’Elia relative à la sécurité d’approvisionnement en Belgique pour 2020-2030 peut être améliorée sur une série de points importants. Ces améliorations permettraient d’aligner davantage cette étude sur la législation européenne existante. Certaines hypothèses de cette étude mènent à une surestimation des besoins.

Vu l’impact du coût d'un CRM sur la facture des consommateurs[6], la CREG estime qu’il est important de déterminer les besoins en capacité de manière plus optimale et plus précise, en tenant compte de la sécurité d’approvisionnement et en évitant de déjà surestimer le volume nécessaire. La CREG suggère de demander à Elia une analyse complémentaire où les améliorations énumérées dans ce document seront intégrées, avant de conclure dans quelle mesure il y aura un éventuel déficit en électricité.

Afin de répondre le plus efficacement possible aux enjeux de la sécurité d’approvisionnement, il est préférable de garder ouverte l'option d'une réserve stratégique, éventuellement adaptée, en plus de l’élaboration d'un CRM à l'échelle du marché. Le Clean Energy Package prévoit en effet une hiérarchie, en vertu de laquelle il convient en premier lieu d’évaluer si une réserve stratégique peut résoudre un éventuel déficit en électricité.

[6] https://economie.fgov.be/sites/default/files/Files/Energy/Rapport-Determination-du-mecanisme-de-remuneration-de-la-capacite-belge-et-preparatio-du-cadre-legislatif.pdf

EXECUTIVE SUMMARY (EN)

On 28 June 2019, Elia published its study on security of supply and flexibility 2020-2030. Elia made a number of significant improvements compared with previous studies, including taking account of flow-based market coupling as regards import capacity and the economic viability test. Nevertheless, it is the CREG's view that, based on the observations set out in this study, its proposals may result in a decrease of the potential capacity shortage.

As a result, Elia's study can also be improved and refined by integrating the elements as analysed and proposed hereinafter by the CREG. The CREG will set out in this document why and how these elements could be taken into consideration. This would bring the study into line with the European Clean Energy Package as far as possible. The CREG also gives its view the formal consultation procedures that should be followed.

1. Elia refers to a simulated shortfall of 3.9 GW, whereas the base case scenario results in a significantly lower shortfall in 2025

In its key message, Elia states that a shortfall of 3.9 GW is expected by the winter of 2025-2026, after the complete phasing out of nuclear capacity. This result is not based on the base case scenario, but on a 'low probability - high impact' sensitivity analysis in which France unexpectedly loses 3,6 GW of nuclear capacity. As a result, France would not be able to guarantee its security of supply, despite a CRM in France.

The base case scenario shows a shortfall of 2.4 GW if the existing thermal capacity in the system can be maintained. It is important to note that the base case scenario, alongside the incorporation of various historical climate years[7], thereby including extreme events such as long periods of little wind and cold spells, also simulated the recent decline in the availability of nuclear power stations (33% to 50% of nuclear capacity unavailable).

Furthermore, the study does not take into account the presence of the existing gas-fired power station in Vilvoorde (265 MW), which reduces the shortfall by at least 0.2 GW.

2. The shortfall as simulated by Elia decreases by 1.4 GW in 2028 to 0.8 GW (compared to 2025).

If all existing capacity is maintained, the simulated shortfall will decrease to 0.8 GW in 2028.

3. In 2025-2026, the shortfall as simulated by Elia will be needed on average for 5-7 hours in order to meet the security of supply criteria.

The results of the base case scenario show that the simulated shortfall takes an average of 5-7 hours to meet the 3h LoLE criterion.

[7] See appendix E.2. of the Elia study : Sets of various meteorological conditions having an impact on renewable generation and electricity consumption. Such conditions (wind, solar radiation, temperature and precipitation) are geographically and time-correlated for a given region and even between countries.

4. Improving the methodology for evaluating the profitability of existing and new capacity

Elia simulates profitability for three years: 2020, 2023, 2025. This is based on a model.

However, market prices are already available for 2020, meaning that the revenues modelled by Elia can be verified. This shows that real market revenues are on average twice as high as the revenues that Elia estimates to be used to assess the economic viability of existing and new capacity. Failing to use the existing market pricing leads to an underestimate and a distorted picture. The results as simulated by Elia should also be improved.

For the economic viability test, Elia uses the median (P50) inframarginal rent from the probabilistic analysis. However, to assess the economic value of capacity, utilities need to hedge their assets. Hedging is done on the forward market. Forward prices do not reflect the expected median (P50) spot price, but do reflect the expected spot prices in all possible scenarios, weighted by their respective probabilities. This boils down to using the <u>average</u> simulated inframarginal and would lead to much more existing capacity that would stay in the market and much more new capacity coming to the market.

The CREG proposes to use this adjusted assessment with the current price ceiling and a higher price ceiling, whereby with a higher price ceiling, the demand management that is added gradually takes on a higher marginal cost in turn.

With regard to co-generation, Elia should take all revenues into account, including those from the existing support mechanism (co-generation or green energy certificates), which is designed precisely to make co-generation profitable. Moreover, a CREG study from 2016[8] shows that new decentralised generation capacity that can be installed after the meter, such as co-generation and gas engines, are actually profitable. However, the impact of having generation capacity after the meter should be taken into account by Elia.

The CREG proposes to take into account the introduction of a 'shortage pricing function' that would significantly improve the profitability of existing capacity.

5. All available balancing reserves in Belgium and abroad should be taken into consideration

Assessing the security of supply criteria should be simulated on the basis of the situation in real time. Indeed, the grid operator must take all possible measures to avoid involuntary disconnection in real time, including the use of the balancing reserves that are not required for balancing at that time and can then be used for ensuring the security of supply. A security of supply problem only arises if the study shows that on average more than three hours are necessary (LOLE criterion) until involuntary disconnection. In addition, foreign reserves can also improve Belgian security of supply. The impact of the use of all available reserves on the non-supplied energy should be simulated in an optimum manner.

6. Contribution from abroad – taking into account market reaction abroad

Belgium's import capacity will reach 7,500 MW within a few years. The simulations show that in 2025 it is expected that less than 2,500 MW on average will be imported, if Belgium were to have a problem with security of supply. During periods of scarcity, import capacity is therefore still available. The

[8] See CREG study 1583 in Dutch: https://www.creg.be/sites/default/files/assets/Publications/Studies/F1583NL.pdf
See CREG study 1583 in French: https://www.creg.be/sites/default/files/assets/Publications/Studies/F1583FR.pdf

shortfall in Belgium estimated by Elia can therefore be (partly) supplied from abroad, if there is no shortfall in that country.

Because import capacity is still available during periods of scarcity, other countries including the Netherlands, Germany, France and the UK will often quote the same high prices as Belgium if Belgium has an electricity shortfall. These prices can be as high as €10,000/MWh and more. If this actually happens, the market will react with a larger supply of capacity in Belgium (this occurred last winter when 1,200 MW capacity was added exceptionally in the space of a few months, thanks also to the measures taken by the authorities), but also in these other countries. Elia takes account, albeit in a manner that needs some improvement (see above), of such a market reaction in Belgium, with an additional 1,000 MW being added, but with largely limited availability. In addition, Elia rules out any market reaction (and therefore additional capacity) in the other countries, even though prices in these countries will also rise to €10,000/MWh or more. The appropriate economic viability test should therefore be performed for the other countries.

In its sensitivity analysis, Elia does consider that gas-fired capacity remains in the market, which reduces Belgium's shortfall by 0.7 GW. However, in the meantime there is even mention of gas-fired capacity returning to the market, and this could be reinforced by Germany's accelerated phasing out of coal. Maintaining and re-introducing gas-fired production capacity should be included in the base case scenario, via the economic viability test.

7. The winter reserves in Germany should be taken into consideration

Germany currently has 6.6 GW of winter reserves. The German regulator anticipates an increase to 10.6 GW by 2022-2023. These reserves are primarily used to stabilise the domestic electricity grid when there is a lot of wind production in the north that needs to be transported to the south. During periods of high wind, no capacity shortfalls are expected.

During periods of low wind, these reserves are therefore largely available, including for meeting Belgium's security of supply if necessary. This should be taken into account in the study. It should be noted that, in order for such capacity to be made available, agreements should be concluded between the member states.

Conclusion

The Elia study on security of supply in Belgium for 2020-2030 could be improved in a number of important areas. These improvements would bring the study more in line with existing European legislation. Certain hypotheses in the study in question lead to an overestimate of the needs.

Given the impact of the cost of a CRM on consumer invoices[9], the CREG is of opinion that it is important to determine capacity requirements in a more precise and optimum manner, bearing in mind the security of supply and avoiding an excessive overestimate of the volume required. The CREG suggests that Elia should be requested to perform an additional analysis which incorporates the improvements listed in this document, before concluding on the extent of any electricity shortfall.

In order to address the concerns around security of supply as efficiently as possible, it is best that, besides the development of a market-wide CRM, the option of a Strategic Reserve (adjusted as necessary) should be kept open. Indeed, the Clean Energy Package does provide a hierarchy that requires an investigation into whether a Strategic Reserve could resolve any electricity shortages first.

[9] See PwC study: https://economie.fgov.be/sites/default/files/Files/Energy/Rapport-Bepaling-van-het-mechanisme-voor-de-vergoeding-van-capaciteit-voor-Belgie-en-de-voorbereiding-van-het-wettelijk-kader.pdf (Dutch) or https://economie.fgov.be/sites/default/files/Files/Energy/Rapport-Determination-du-mecanisme-de-remuneration-de-la-capacite-belge-et-preparatio-du-cadre-legislatif.pdf (French)

1. INTRODUCTION

1. On June 28th 2019, Elia published its study on the adequacy and flexibility of Belgium in 2020-2030[10]. Since the modification of the Belgian Federal Electricity Act in July 2018, article *7bis, §4bis,* assigns *the* transmission system operator with a biennial task to perform an adequacy and flexibility assessment of the Belgian electricity system with an outlook for the next ten years. This analysis is to be conducted in collaboration with the Directorate General for Energy and the Federal Planning Bureau and in concertation with the regulator.

2. Besides a number of meetings, a public consultation was organized by Elia between January 21st and February 11th on input data for this assessment. Although this consultation was not a legal obligation, the CREG considered this consultation as insufficient for the reasons explained in note (Z)1901 of the CREG.

3. Among the documents contained in the Clean Energy Package, recently adopted by the European Union, is Regulation (EU) 2019/943 on the internal market for electricity. This Regulation contains provisions with which Member States must comply when considering the establishment of a capacity remuneration mechanism (CRM).

4. In particular, it should be noted that, according to these provisions, a CRM can only be introduced by a Member State on the condition that an adequacy problem has been identified for the Member State in question, through an assessment conducted either at European level (by ENTSO-E) or at national level and according to a methodology adopted by ACER.

5. In addition, the Member State must demonstrate to the European Commission, through an implementation plan, that it has taken the necessary measures to improve the Energy Only Market as much as possible, but that these measures are not sufficient for resolving the adequacy problem, and the establishment of a strategic reserve would not resolve the situation either. The establishment of a capacity remuneration mechanism therefore appears to be a measure of "last resort" (Article 21).

6. Regulation 2019/943 also lays down the basic principles to be respected by capacity remuneration mechanisms, including their temporary and proportionate nature, the need to select capacities according to a competitive procedure, and technological neutrality. It also lays down the conditions for participation in the CRM of the capacities located in other Member States.

7. Regulation 2019/943 will be directly applicable as of 1 January 2020. In the meantime, it has already entered into force (on 4 July 2019), which means that Member States must refrain from taking any measure that would run counter to its provisions.

8. The extent to which the Law of 22 April 2019 (which introduces CRM into the Electricity Act) needs to be adapted in order to bring it into line with Regulation 2019/943, as well as the impact on the implementation of the Belgian CRM of the procedures and formalities provided for in this Regulation, are currently being discussed and analysed by the Monitoring Committee for the CRM, which is made up of the cabinet of the Minister for Energy, the FPS Economy, Elia and the CREG.

[10] See the Elia study on adequacy and flexibility of Belgium in 2020-2030: http://www.elia.be/~/media/files/Elia/publications-2/studies/20190628_ELIA_Adequacy_and_flexibility_study_EN.pdf

2. ANALYSIS OF THE ELIA STUDY

9. In this chapter, the CREG will analyze the Elia study regarding adequacy, make comments and propose improvements to the study. This chapter has two sections in which the following topics are examined: (i) methodology, scenarios and assumptions, and (ii) results and sensitivities.

2.1. METHODOLOGY, SCENARIOS AND ASSUMPTIONS

10. To assess the Belgian situation in terms of adequacy, not only does ELIA simulate Belgium, but 20 other countries in Europe. Elia applies a probabilistic approach and uses the reliability standard stipulated in the Belgian Electricity Act : a LoLE of 3 hours on average and 20 hours in a P95 scenario (a situation that is expected to occur once every twenty years). Elia uses the ANTARES-model.

11. In the subsequent sections, the CREG will elaborate on various topics related to the methodology, scenarios and assumptions used by Elia.

2.1.1. Economic assessment of capacity

12. To assess the resource adequacy for Belgium, Elia developed a methodology to take the market reaction into account. It verifies how much existing and new capacity is economically viable through an iterative process. This assessment is a significant improvement compared to the earlier methodology (based on the age of generation units).

13. However, Elia only applies this assessment to Belgian assets, not to assets in foreign countries. The CREG believes that this assessment should also be made at the least for assets in the neighboring countries and ideally in all simulated countries, since capacities in foreign countries can also contribute to the adequacy in Belgium (see below).

14. The CREG made a sanity check of the revenues calculated by Elia and identified what the CREG considers some important flaws in the methodology used by Elia to calculate the market revenues. This will be elaborated on in this section.

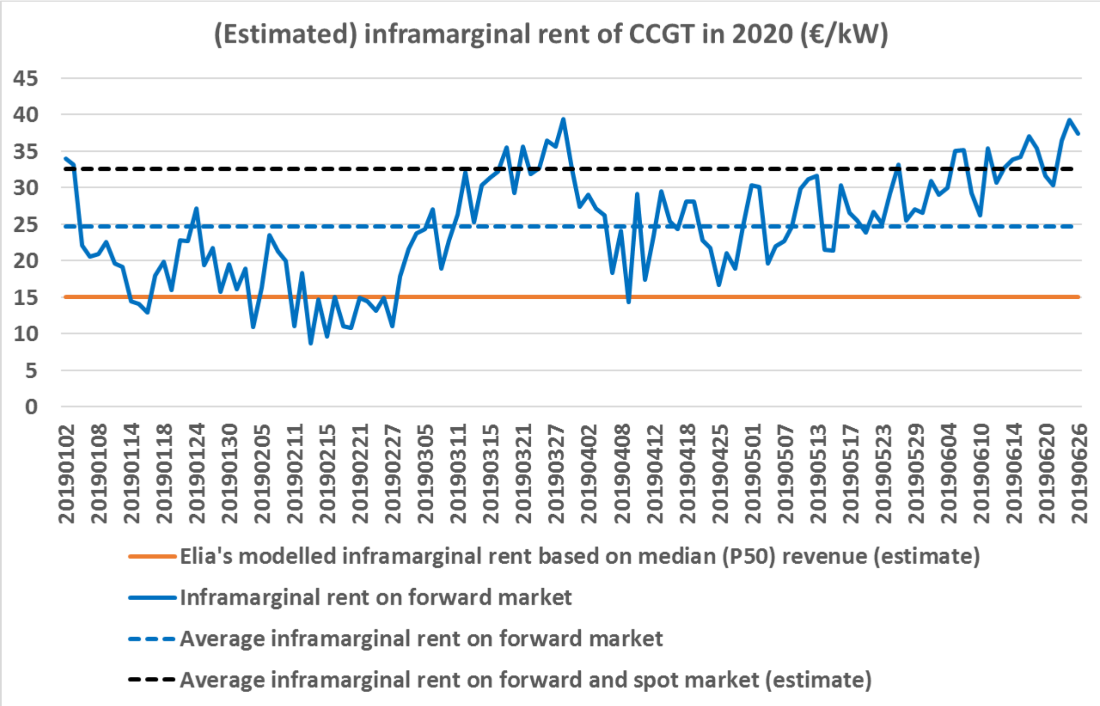
2.1.1.1. Check of inframarginal rent calculated by Elia

15. For each type of capacity, Elia calculates the inframarginal rent, which can be viewed as the operational profit without taking into account the fixed operational cost. These inframarginal rents are based on prices derived from the ANTARES-model. The CREG did not find any sanity check in the Elia-study which ascertains whether or not these modelled prices reflect the prices in the real world. However, since Elia also simulates the inframarginal rents for 2020 and since there are already forward market prices available for 2020, the CREG performed a sanity check on Elia's 2020-results.

16. Figure 4-13 in the Elia-study shows the inframarginal rents for different types of capacity for 2020 and 2023. For existing CCGTs in 2020 without the need for refurbishment, the P10 inframarginal rent is simulated at about 11 €/kW, the median (P50) inframarginal rent at about 15 €/kW and the P90 at about 23 €/kW for a CO2-price of 20 €/tonCO2. Elia uses the median (P50) inframarginal rent to decide whether the generation unit, in this case a CCGT, is profitable or not in its 'market viability test'.

17. The true market inframarginal rent can already be calculated based on the forward prices for electricity, gas and CO2, for delivery in 2020. The full blue line on the figure shows this inframarginal rent on the forward market and is generally higher than Elia's modelled median (P50) inframarginal

rent (orange line). This inframarginal rent on the forward market can change daily, because forward prices can change daily. The figure shows all trading days of the first half of 2019. The average inframarginal rent on the forward market during the first half of 2019 is shown by the dotted blue line and is 25 €/kW or 65% higher than Elia's simulated P50-inframarginal rent of 15 €/kW. This inframarginal rent of 25 €/kW on the forward market is a locked-in revenue.



18. Moreover, even the inframarginal rent calculation for generation units based on the forward prices is an underestimate, since this is based on a baseload forward price, assuming the CCGT will run all hours of the year. This will clearly not be the case, since a CCGT is not always profitable to run. During weekends and nights and summer days, the clean spark spread (CSS) is likely to be negative and the unit will not run. CCGTs are usually hedged on the forward market[11], so when the unit is not running, the gas and the CO2 (that was bought on the forward market) will be sold on the spot market and the electricity (that was sold on the forward market) will be bought on the day ahead market, generating an additional profit. This additional profit can be even higher than the profit made on the forward market. The CREG explained this so-called 'asset-backed' trading strategy in detail in its study 1628[12]. This study calculated the historical operational profit of existing CCGTs in Belgium between 2007 and 2017. These results were updated in 2019 to include the year 2018.

[11] Hedging a CCGT is done by buying gas and CO2 (which creates a long position) and selling electricity (which creates a short position) on the forward market. Assume a CCGT was hedged for 2020 by selling baseload power at 52 €/MWh on average, buying the equivalent volume of gas at 18 €/MWh on average and the equivalent CO2-emission allowances at 26.5 €/tonCO2 on average (= forward prices on 28 June 2018). With a 50% efficiency, an O&M cost of 2 €/MWh, an availability of 91% and an expectation to run 50% of the time, this leads to a locked-in inframarginal rent of 42 €/kW. For a CCGT of 400 MW, this results in an inframarginal rent of 16.8 M€.
If during the 3 summer months of 2020, the electricity price was 30 €/MWh, gas 15 €/MWh and CO2 30 €/tonCO2, the CCGT would not be profitable and would not run. The producer will then buy the electricity at 30 €/MWh (to fulfill its contract), sell the equivalent volume of gas at 15 €/MWh and CO2 at 30 €/tonCO2 and make an additional inframarginal rent of about 24 €/kW during these 3 months. For a CCGT of 400 MW, this results in an additional inframarginal rent of 9,6 M€.
The total inframarginal rent equals 66 €/kW or 26.4 M€ for a 400MW-CCGT. This is more than 50% higher than if only the inframarginal rent on the forward market is taken into account.

[12] Study 1628 in Dutch: https://www.creg.be/sites/default/files/assets/Publications/Studies/F1628NL.pdf
Study 1628 in French: https://www.creg.be/sites/default/files/assets/Publications/Studies/F1628FR.pdf

19. From study 1628, it can be inferred that for certain years this additional profit could be as high as 50 €/kW. Historically, this additional profit in 2007-2011 [13] was 32% of the profit on the baseload forward market. If we take 32% of additional inframarginal rents[14], this leads to an inframarginal rent on the forward and spot market combined of 32.6 €/kW. This is more than twice the Elia's P50 estimate of 15 €/kW (and 42% higher than Elia's high (P90) estimate of 23 €/kW).

20. On the basis of the above-mentioned explanations one can conclude that the modelled inframarginal rent used by Elia underestimates the inframarginal rent based on the current forward prices for 2020 by a factor 2. Since Elia's assumptions are rather conservative (e.g. 2 GW nuclear capacity unavailable in 2020), it could be expected that Elia's calculations of the inframarginal rent would exceed those based on the forward market prices. In the following sections, the CREG will take a deeper look at the methodology and will highlight its point of view regarding the methodology used by Elia.

2.1.1.2. Price formation

21. To evaluate the profitability of the existing units, Elia uses the prices derived from the ANTARES-model. The Elia-study states that ANTARES calculates the optimal unit commitment and generation dispatch from an economic perspective, minimizing the generation costs and providing the hourly marginal prices per country as output. This does not correspond to the price formation under flow-based market coupling with the Euphemia algorithm as is currently applied in the CWE (Central Western Europe) region.

22. Euphemia maximizes social welfare instead of minimizing generation costs. The first difference is that, by accounting for the consumer welfare in the optimization, the flow-based price formation inherently introduces some element of scarcity pricing, leading to a higher profitability of generation capacity in Belgium compared to the situation where the marginal unit sets the price. The Euphemia-algorithm can lead to market prices being higher than the marginal price of the marginal unit, especially when the supply-demand is relatively tight. In October-November 2017, day-ahead prices higher than the marginal cost of the marginal generation unit were observed. The CREG received 10 enquiries requesting it to have a detailed look at the order book of market parties bidding on the power exchange. Given that a gas-fired power plant is typically the marginal power plant when prices are high, underlying gas price movements did not explain the elevated electricity prices above the marginal cost of a gas-fired power plant. The CREG did not detect any suspicious behavior and explained why day-ahead prices can be higher than the marginal cost of the marginal unit, especially during periods of scarcity, with the Euphemia-algorithm implementing the day-ahead flow-based market coupling. For smaller bidding zones such as Belgium, the scarcity price premium could be even higher than for the larger neighboring bidding zones due to the flow factor competition. These findings were published in a CREG-note 1715[15].

23. As such, according to the CREG, the price formation in any model to assess the profitability of generation units in Belgium should reflect the price formation that occurs under a flow-based market coupling mechanism.

[13] The period 2007-2011 was taken as a reference period, as similar revenues on the baseload forward market could be generated as in recent years. Including the period 2012-2017, in which baseload forward profits were very low, would lead to a much higher relative additional profit and could be criticized as being unrealistic high. CREG's approach can as such be considered as conservative.

[14] This 20% additional revenue for 2020 based on the 2007-2011 period is most likely an underestimate, because increasing RES makes electricity on the spot market more volatile, leading to more negative clean spark spreads and hence higher additional profits on the spot market with an asset backed trading strategy given the same baseload forward price.

[15] See section 2.4.1 of CREG-note 1715: https://www.creg.be/sites/default/files/assets/Publications/Notes/Z1715EN.pdf

24. Correct modeling of the price formation is not only essential for assessing the profitability of capacity, but also for assessing the import volumes. In a previous market coupling model, with an allocation of cross-border capacity through the calculation of bilateral net transfer capacity (NTC), prices in two price zones (countries) were the same when the NTC between these two price zones was not saturated. If the NTC was fully used and the importing country wanted to import more (but was unable to), it would need to use its own, more expensive domestic capacity, leading to a higher price for the importing country. It is important to understand that, with NTC market coupling, even if the price in the importing country would become exorbitant, say 10,000 €/MWh or higher, this would not lead to more imports to this country.

25. With the flow-based market coupling algorithm, implemented through the Euphemia-algorithm, this is no longer the case. Network constraints are translated into a set of feasible combinations of bidding zone net positions (flow-based domain) instead of feasible NTC-values per border. Within this feasible set, the social welfare optimization will optimize the bidding zone net positions to maximize the import capacity to a price zone (country) which is willing to pay high prices, leading to higher import capacity to that price zone. An important element is that the import volume with flow-based market coupling therefore depends on the willingness to pay, which is reflected in the consumer surplus.

26. For Belgium, this means that, when close to scarcity, the flow-based algorithm will ensure higher import volumes to Belgium by shifting the location from where Belgium imports, if Belgian consumers are willing to pay for this additional capacity. It can be seen from the flow-based domains that Belgium is able to import more from France and Germany than from the Netherlands. With flow-based market coupling, France and Germany are therefore better locations for extra capacity for Belgium. However, Elia does not consider a market reaction to higher prices (leading to more capacity) in these locations in its simulations (see below).

27. To summarize, an adapted modelling of the price formation under flow-based market coupling is essential for the adequacy study, since it determines both the profitability of capacity and the import volumes.

28. The CREG asked Elia whether the price formation in the ANTARES-model is mimicking the Euphemia-algorithm used in flow-based market coupling in CWE. Elia confirmed by letter that their model is mimicking the flow-based market coupling price formation. At first glance, this is not in line with the description of the price formation of ANTARES in the Elia study. (see par 28). The CREG will ask Elia for further explanation.

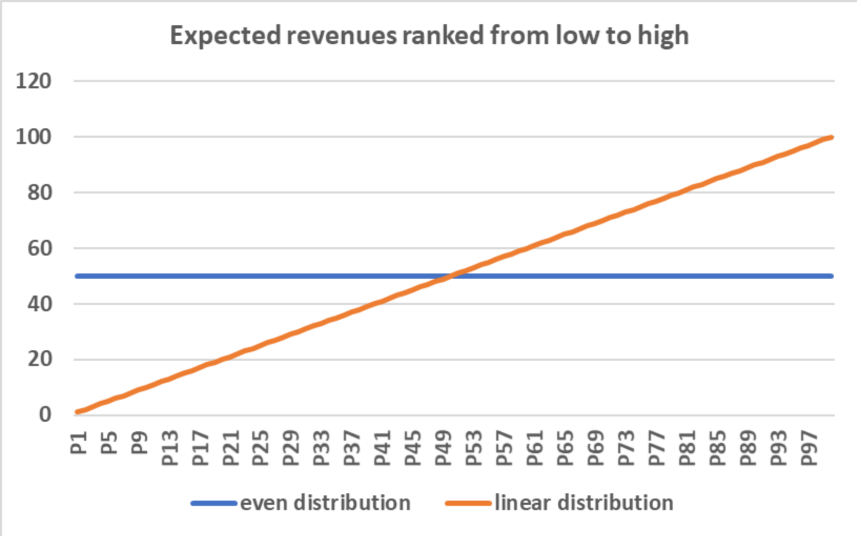
29. Moreover, additional revenues from arbitrage activities between forward, day-ahead, intraday and real-time markets are not taken into account in the methodology used by Elia. These additional revenues could increase the economic value of capacity, thereby increasing the available capacity in the market.

2.1.1.3. <u>Use of median (P50) revenues</u>

30. According to the CREG, an essential flaw in the economic viability check relates to the selection of the revenues used to make the economic assessment.

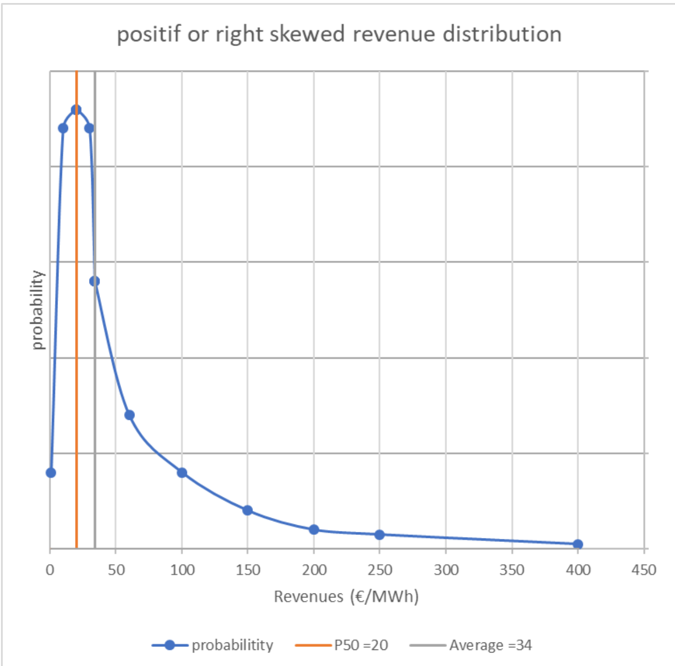
31. Elia uses a probabilistic approach, simulating yearly (Monte Carlo years) revenues according to several hundreds of different generation patterns of renewables and forced outages. It ranks these Monte Carlo years from low to high revenues. For the economic viability check of a certain type of capacity, the ranking is done based on the revenues for that specific type of capacity. The ranking consists of 100 percentiles, where e.g. the P01 represents the lowest revenue and the P100 is the highest revenue. The P50 is the median revenue.

32. Elia uses the median (P50) revenue to check whether a capacity is economically viable or not. If the revenues are more or less evenly or linearly distributed, than the median revenue (P50) is more or less the equivalent to the average revenue. This is shown in the figure below, which shows the revenues for each percentile for an even (uniform) and linear distribution. In this example, the median (P50) revenue for both distributions is 50; the average revenue for the even distribution is also 50, whereas the average revenue for the linear distribution is 50.5.

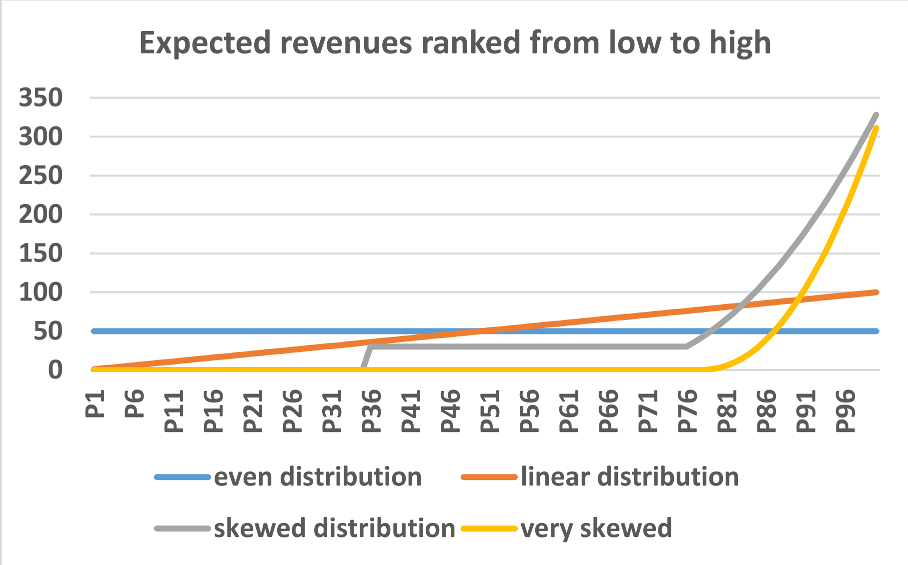


33. However, the revenues in the power sector are far from evenly or linearly distributed; they are highly skewed. This is all the more so when there are years when scarcity could occur, leading to prices reaching the market price cap.

34. It is essential to note that when the revenue distribution is highly skewed, as it is in power markets, the median (P50) revenue is much lower than the average (expected) revenue. The figure below is an illustrative example of the distribution of revenues in power markets, where a maximum market revenue of 400€/MWh is simulated. In this example the median (P50) revenue is around 20 €/MWh while the average revenue that can be expected is 34 €/MWh. During periods of scarcity, the maximum price cap (currently 3,000 €/MWh) will be reached and the difference between median (P50) and average revenues will further increase.



35. The figure below shows the same figure as before but with the addition of two skewed distributions, with one being more skewed than the other. The grey line represents an average revenue of 50, whereas the median (P50) revenue is only 30. The yellow line represents an average revenue of 25, whereas the median (P50) revenue is 0.



36. It should be clear that using the median (P50) revenue does not or only partly takes into account the occurrences of high prices (scarcity prices). Given that there is no scarcity at P50, as Elia explained to the CREG during an informative meeting, the median (P50) revenue will not be impacted by situations of scarcity and by the market price cap. As such, an increase of the market price cap cannot, by this design, have a significant impact.

37. Therefore, the median (P50) revenue of a capacity with a skewed revenue distribution underestimates the real economic value of that capacity and consequently the capacity supply in the Belgian market[16].

38. Importantly, the median (P50) revenue from a probabilistic analysis is not how the economic value of capacity is assessed. Utilities need to hedge their assets. Hedging is done on the forward market. Forward prices do not reflect the median (P50) spot price, but do reflect the expected spot prices, which are the spot prices in all possible scenarios, weighted by their respective probabilities[17]. If a probabilistic model to simulate spot prices is used, the only correct way to base the economic assessment of capacity is to calculate the expected simulated spot price according to all simulations, weighted by their probabilities. For probabilistic revenues ranked in percentiles, this boils down to using the average simulated spot prices (so using all simulated revenues from P01 to P100). This could be differentiated by calculating baseload or peak forward prices.

[16] According to Elia, the median ('percentile 50' or P50) inframarginal rent equals a "1 out of 2" situation (see section 3.2.2). This is not correct. The median (P50) has a probability of 1% to occur. It is correct to say that for one year there is a 50% chance to have an inframarginal rent that is higher than the median, and a 50% chance to have an inframarginal rent that is lower than or equal to the median. But in the first case, when the inframarginal rent is higher than the median, the inframarginal can be *much* higher than the median (due to the skewed distribution of the revenues). In the second case, when the inframarginal rent is lower than the median, the inframarginal rent will be close to the median.

[17] See the seminal paper by Bessembinder and Lemmon (2002) (http://www.tapir.caltech.edu/~arayag/PriHedFws.pdf) in which they state that: $P_F = E[P_W] + \alpha * Var(P_W) + \gamma * Skew(P_W)$ with P_F the forward price, P_W the wholesale spot power price and E[.] the expected value. $Var(P_W)$ decreases the risk premium, while $Skew(P_W)$ increases the risk premium.

39. To summarize this crucial element: it is essential to understand that utilities need to hedge their assets, that these assets are hedged on the forward markets and that forward prices reflect the expected spot price. The expected spot price from a probabilistic simulation that ranks the results in percentiles equals the average simulated spot prices. This is important, because by calculating the average, the possibility of scarcity prices is also taken into account. The possibility of scarcity prices is incorrectly disregarded by using the median (P50) prices.

40. Another way of looking at this is by calculating the expected inframarginal rent over the total economic lifetime of the investment. Figure 2-63 of the Elia study shows the 'investment economic lifetime' in years for different technologies. A refurbishment of an existing CCGT has an economic lifetime of 15 years, according to Elia (the CREG assumes 20 years or more[18]). For new market response it is 10 years, according to Elia. By using the median (P50) inframarginal rent to decide whether a new investment is profitable, the possibility of having an inframarginal rent in the P81-P100 interval which has a probability to occur of 20% is not taken into account.

However, over the economic lifetime of 10-20 years, having a year with an inframarginal rent in the P81-P100 interval is very likely to occur: the probability of having *at least* one event in 10 years that is expected to occur in 20% of the cases is 89% (if these events are independent), for 15 years this probability increases to 96.5% and for 20 years this is 98.8%. If we use the P90 inframarginal rent as a proxy for the average inframarginal rent for such a 20% event (P81-P100)[19], the expected inframarginal rent during such an event for a refurbished CCGT is 180 €/kW or double the minimal investment cost of 90 €/kW and almost 7 times the minimal annuity of 27 €/kW. The expected inframarginal rent for new market response is above 140 €/kW or 14 times the minimal investment cost of 10 €/kW and more than 20 times higher than the minimal annuity of about 7 €/kW.

It should be noted that these inframarginal rents are calculated with a market price cap of 3,000 €/MWh. If (near) scarcity were to occur, this market price cap could easily rise to 10,000 €/MWh and higher (see below), sharply increasing the average inframarginal rent for a 20% event (P81-P100). This is all disregarded by applying the median (P50) approach.

41. By using forward prices, the probability of 20% events and price spikes is taken into account. If this probability is low (say on average 1 hour per year) and the price spike is relatively low (say 1,000 €/MWh) then the impact on the baseload forward price is negligible (1,000 * 1 / 8,760 = +0.11 €/MWh). However, if the probability is relatively high (on average 10 hours per year) and the price spike is high (10,000 €/MWh), then the impact on the forward price will be high (10,000 * 10 / 8,760 = +11.4 €/MWh). This impact on the forward price will then be passed on to the revenue of the capacity.

42. Using the average simulated spot price will probably still lead to an underestimate of the true economic value of capacity, since forward prices generally have a positive risk premium. This, on average, leads to a higher price on the forward markets compared to the spot prices for the same delivery period. One solution could be to add the historical positive risk premium to the average simulated spot prices.

43. Using the average simulated spot prices will lead to a significantly different outcome compared to using the median (P50) revenue, since when calculating the average, occurrences with very high prices will also be taken into account (weighted by their probability of occurring). An important consequence is that the average LoLE can be used to calculate the minimal inframarginal rent of all types of capacities (given that this capacity is available during scarcity). The table below shows the

[18] A lifetime extension of a CCGT typically adds 100,000 equivalent running hours, which implies an economic lifetime of 20 years if one assumes an average of 5,000 equivalent running hours per year.

[19] Using the P90 is an underestimate of the real expected average inframarginal rent for the interval P81-P100, because the inframarginal rent distribution in this interval is also skewed.

minimal inframarginal rent if only periods during scarcity in 2025 are considered, as simulated by Elia. The average "market" LoLE in 2025 according to Elia is 9.4 hours in the EU-base scenario[20].

For a market price cap of 3,000 €/MWh, this leads to a minimal inframarginal rent of 27 €/kW generated during these 9.4 hours (taking into account a generation cost of 100 €/MWh). With this minimal inframarginal rent, new market response (with an annuity between 8-22 €/kW) will be profitable. Furthermore, some CCGTs that need refurbishment (annuity of 25-45 €/kW) could become profitable.

Minimal inframarginal rent (from LoLE only) (€/kW)			
price cap (€/MWh)	**average "market" LoLE (hours/year)**		
	9.4 hours	**6 hours**	**3 hours**
3,000	27	17	9
10,000	93	59	30
20,000	187	119	60

44. Additionally, every time 60% of the market price cap is reached, this price cap will automatically increase by 1,000 €/MWh. Before reaching the market price cap, there is a fair probability that the 60% threshold will be triggered multiple times if a country is near scarcity. A market price cap of 10,000 €/MWh is then not unrealistic. With a market price cap of 10,000 €/MWh and on average 9.4 hours of "market" LoLE, the minimal inframarginal rent increases to 93 €/kW, making all CCGTs with refurbishment costs profitable (annuity of 25-45 €/kW).

45. It can be argued that by adding capacity, the profitability of the capacity already in the market will decrease. Capacity will be needed until the average LoLE of 3 hours is reached. With a market price cap of 10,000 €/MWh and 3 hours LoLE, the minimal inframarginal rent only during these LoLE-hours is 30 €/kW. Again, this makes all market response profitable. If the market price cap further increases to 20,000 €/MWh, this would also make all CCGTs with refurbishment costs profitable, even if we only consider the impact of possible scarcity on the revenues.

46. Importantly, capacity does not have to be added until the average "market" LoLE of 3 hours is reached. The real LoLE is in real time and needs to take into account all measures to avoid forced load disconnection, such as using balancing reserves, but also market-based measures that are not offered to the day-ahead or intraday market[21]. This implies that a country could have a "market" LoLE well above 3 hours, while meeting the criterion of the 3 hours of LoLE in real time. To address this issue, a column in the table above has been added with a "market" LoLE of 6 hours. Here it can be seen that CCGTs with refurbishment costs would already be profitable at a market price cap of 10,000 €/MWh (or lower), even if we only consider the impact of possible scarcity on the revenues.

47. It should be noted that new CCGTs could also become profitable. This would be in line with the Elia study from November 2017 in which Elia assessed that 1.6 GW of new CCGTs could be profitable in the market.

[20] For the economic assessment, the "market LoLE"can be used, since this indicates the number of hours the market price cap is reached. In assessing whether Belgium meets its reliability criteria, all measures should be taken into account to avoid a forced load disconnection, including measures outside the market, such as balancing and strategic reserves. This approach results in the real LoLE.

[21] See for example the so-called "pass-through contracts" that are indexed on the imbalance tariff: these consumers do not offer their capacity to the day-ahead or intraday market but are expected to react in real time when imbalance tariffs spike. The total volume covered by pass-through contracts in Belgium is well above 500 MW.

48. Of course, here we only calculate the minimal inframarginal rent based on the average LoLE. To calculate the total inframarginal rents, the model would need to run again, using the average simulated inframarginal rents, instead of the median (P50) inframarginal rent, since all types of capacity can have inframarginal rents outside LoLE-periods[22].

49. Another important element is that using the median (P50) inframarginal rent would be a risk-averse approach. Due to the highly skewed distribution of revenues, using the median (P50) could indeed be a risk-averse approach from an investor's viewpoint, where the inframarginal rent is the upside for the capacity-holder. But this inframarginal rent is the downside or (opportunity) cost for the supplier or the balancing responsible party (BRP) from not having this capacity. Indeed, scarcity can only occur when one or more BRPs/suppliers are short[23]. These BRPs will have to pay the market price cap during periods of scarcity. As such, using the median (P50) inframarginal rent to decide whether to keep existing capacity (or to develop new capacity), is a risk-*loving* strategy from the viewpoint of the BRP/supplier. The BRP/supplier then ignores all possible losses beyond the median P50 (P51-P100), which on average represent a higher cost than the possible losses in the P1-P49-range. Indeed, by only considering the median (P50) inframarginal rent, the BRP/supplier puts zero weight to the P51 to P100 possible losses.

50. A risk-neutral strategy for a BRP/supplier would be, again, to use the average inframarginal rent. A risk-averse strategy, would be to put *more* weight to high losses, the exact opposite to what Elia does with its P50 approach.

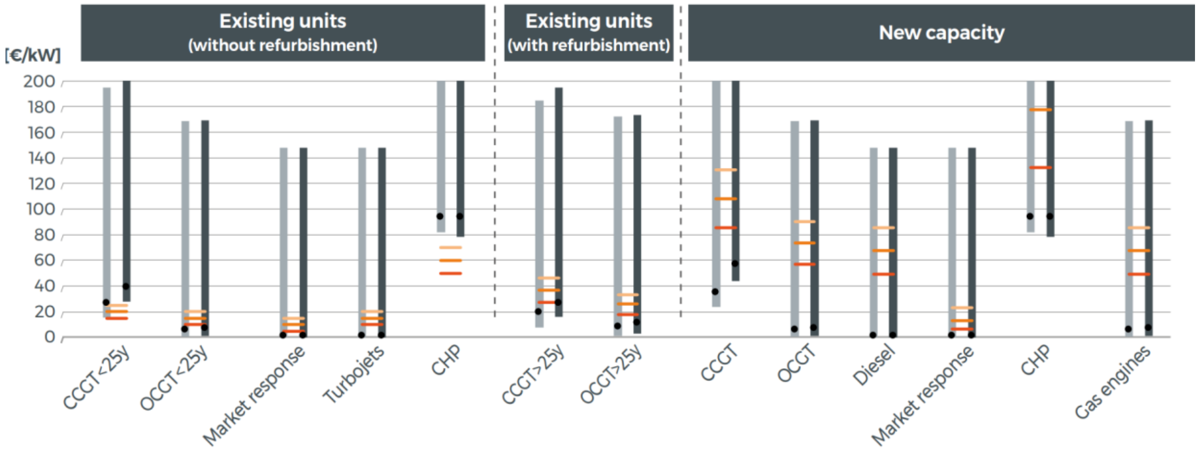
51. Using the median (P50) inframarginal rent underestimates the true economic value for all kinds of capacities. The impact of this underestimate is highest for peak capacity, such as OCGTs, gas engines and market response (including demand response and emergency generators), since for these capacities, the inframarginal rent distribution is more skewed than for CCGTs or CHPs.

52. This is also shown by the results of the economic viability check as published by Elia in its study. The figure below is a screenshot of these results for 2025 for the central EU-base scenario with a market price cap of 3,000 €/MWh[24]. The lower and upper end of the grey bars show the P10 and P90 expected inframarginal rent (with dark grey applying a high price of CO_2; the light grey is the lower price). The black dot represents the median (P50) inframarginal rent. The short yellow/orange lines are the estimated yearly fixed costs of having this capacity. From this figure, it can be seen that all inframarginal rent distributions are highly skewed, implying that the median (P50) inframarginal rent is much lower than the average inframarginal rent.

[22] When there is curtailment in one hour, it can be expected that a number of other hours will see very high prices, even though there is no curtailment during those other hours.

[23] Note that in a EOM with strategic reserves, load shedding can only occur when all balancing reserves, SR and other measures are exhausted. Load shedding will then only occur when there is a large shortage with BRPs.

[24] Elia also simulated the inframarginal rents with a market price cap of 20,000 €/MWh but did not publish details on the results, like the P10, P50 and P90 inframarginal rents. By using the median inframarginal rent, only 300 MW of extra capacity is evaluated by Elia to become profitable.



53. For market response, the consequence of applying the median (P50) inframarginal rent approach is even more pronounced: the median (P50) now coincides with the P10 and even P01, since the expected inframarginal rent for median (P50) years is zero or close to zero. Indeed, during median years, the results show there is no scarcity whatsoever, and hence no high prices. Consequently, the market response, having a high marginal cost to activate, earns nothing. By only considering the median (P50) inframarginal rent, this capacity, even if it has a very low fixed cost of around 10-20 €/kW per year, is evaluated as not being profitable by Elia.

54. But of course, by its design, market response is only used during years where prices would spike. It should be viewed as a kind of insurance against adverse events, when prices are spiking which could bankrupt a BRP/supplier with a shortage. On top of this, the market response has a low lead time of less than one year and sometimes just a few months (see below).

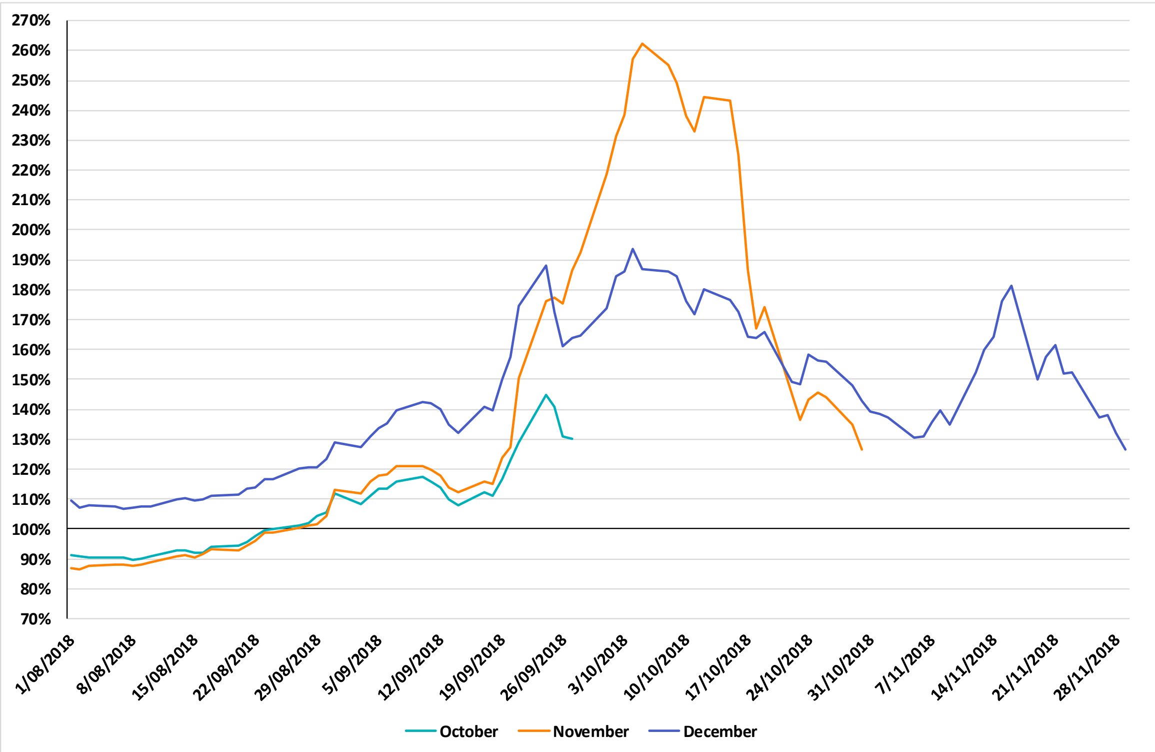
55. Managing price risk is crucial in power markets where prices can easily multiply by 50 to 100 in the event of scarcity. BRPs and suppliers will protect themselves with physical and/or financial insurance. There is a clear analogy with the insurance sector, where it is rational for a risk-neutral or risk-averse actor to buy an insurance product that costs less than the expected (average) loss. By working with the median (P50) inframarginal rent, Elia disregards the sound risk management practices applied by BRPs and suppliers, and implicitly assumes that all BRPs and suppliers, who are at risk of a shortage during periods of scarcity, are risk-seeking actors.

56. By only considering the median (P50) inframarginal rent, increasing or removing market price caps have no significant impact on security of supply. This goes against the logic of why the European legislator imposes the removal of price caps. Indeed, whereas (24) of the Regulation on the internal electricity market states: "(…) *Effective scarcity pricing will encourage market participants to react to market signals and to be available when the market most needs them and ensures that they can recover their costs in the wholesale market. It is therefore critical to ensure that administrative and implicit price caps are removed in order to allow for scarcity pricing. When fully embedded in the market structure, short-term markets and scarcity pricing contribute to the removal of other market distortive measures, such as capacity mechanisms, in order to ensure security of supply.* (…)" It should come as no surprise that only using the median (P50) inframarginal rent (and hence ignoring the effect of removing the price cap) leads to the conclusion that a capacity mechanism is necessary.

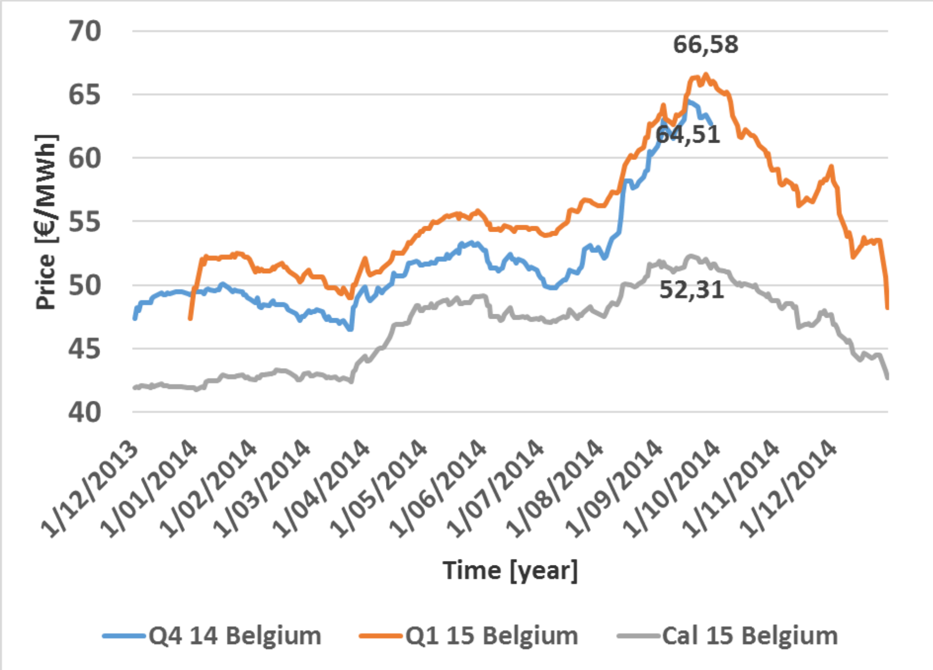
57. The implicit assumption by Elia is also different from what happens in the real world. Last winter, several market players added capacity to address the power crisis in Belgium, due to the unexpected unavailability of nuclear capacity. In total, more than 1,000 MW of capacity was added in just a few months, mostly market response with high marginal costs, such as rented emergency generators and demand response. Even when nuclear capacity came back online, some actors continued to add emergency generators or contracted significant amounts of reserve capacity with third parties. This was partly a reaction to the increase of the imbalance tariff to at least 10,500 €/MWh, increasing the

need for risk management. This behavior would be inconsistent if BRPs/suppliers only considered the median (P50) losses, but the behavior is in line with what can be expected if the more extreme events, with a high impact/price, are also considered, even though they have a low probability of occurring.

58. Furthermore, forward markets react if the risk of scarcity increases. From standard economic theory, it follows that a forward price equals the expected spot price plus a risk premium. The expected spot price is the spot price in all possible situations weighted with their probability, also more extreme situations. In line with the economic theory, the Belgian forward prices reacted in the past on the risk of scarcity, even though this risk has never materialized to date. For the past winter, the forward prices for October, November and December increased sharply on the news of the unexpected unavailability of nuclear capacity. The figure below gives the baseload forward price relative to the average spot price for the same delivery period. It can be seen that the November forward price went up to 260%(!) of the average spot price in November, as a reaction to the scenarios in which scarcity could occur. After several measures were announced to address the scarcity situation, including additional emergency generation capacity and demand response (all capacities with a short lead time), and more import capacity, the forward prices quickly fell. However, for all three months, the forward price just before the start of the respective delivery period stayed about 30% above the average spot price.



59. A similar price pattern was seen during another period in which Belgium was at risk of scarcity. In 2014, half of the nuclear capacity became unavailable: two units at end of March 2014 and one at the beginning of August 2014. Again, in line with economic theory, the forward market reacted to the risk of scarcity, taking into account the scenarios in which scarcity could occur. But this time, the forward price also decreased when it became clear that additional capacity, primarily demand response, was being contracted by suppliers. Once again, no scarcity materialized.



60. Using the median (P50) inframarginal rent for a capacity when the revenue distribution is highly skewed underestimates the true economic value of that capacity. Instead, the average revenue should be used as a minimum, as is the case for forward prices. This approach will make more capacity economically viable.

2.1.1.4. <u>No additional market revenues</u>

61. Revenues calculated by Elia are solely based on the outcome of the day-ahead market results generated by the Antares model. Additional revenues coming from arbitrage activities between forward, day ahead, intraday and real-time markets are not taken into account in the methodology used by Elia.

2.1.1.5. <u>No shortage pricing function applied in the model</u>

62. Elia did not integrate a shortage pricing function in its price formation model. A scarcity pricing mechanism based on the operating reserve demand curve (ORDC) would increase the profitability of existing CCGTs in Belgium, preventing them from leaving the market. This should be taken into account in the methodology applied by Elia.

63. Detailed numerical analyses of the Belgian market have demonstrated the potential of scarcity pricing to significantly improve the financial viability of flexible technologies in Belgium, and also to create a strong investment signal for mobilizing demand response. An appealing aspect of the mechanism is the fact that it can co-exist with capacity markets, whether strategic reserves or a market-wide CRM.

64. The latest study conducted by Université Catholique de Louvain for the CREG on this issue provided a practical design for the implementation of a scarcity pricing mechanism which is compatible with the many constraints associated with implementing this kind of mechanism in Belgium. The proposed mechanism uses the creation of real time (balancing time frame) markets for reserves, and avoids any request of modification of the EU wide day-ahead market coupling mechanism (Euphemia). The mechanism proposed uses one adder for the energy price and two adders for the price of the two

types of reserve (aFRR and mFRR) used in Belgium. These adders spike when the volume of reserves is scarce.

65. In October 2019, Elia will start publishing the three adders in day plus one, in order to allow market players to better understand the functioning of this mechanism. If all tests turn out to be successful, and if the final adaptations of the current design to the evolving European balancing market design are successful, the CREG intends to ask to Elia to implement the proposed mechanism in 2021.

66. This summer, the CREG will publish a note on the design proposed for the implementation of this mechanism in Belgium. The CREG considers that the introduction of a scarcity pricing mechanism which evaluates the reserves available in the system constitutes a no-regret measure in the scope of the profound changes required in the design of electricity markets, linked to the introduction of renewables with intermittent generation and with low variable costs.

2.1.1.6. Economic viability of CHP

67. The economic viability check for new CHP is negative, according to Elia. However, the use of the CHP is only based on the simulation of the electricity market. This means that Elia simulates the CHP as it runs as a standard gas-fired unit, where no demand for heat, and hence no revenues for heat, is taken into account.

Elia writes (pg 134): *"Given a higher total efficiency (electricity + heat generation), it could capture higher electricity revenues as it would run more hours during the year (than standard gas-fired units). While existing CHP seems to be viable, new capacity is not (relying purely on energy market revenues). For the reasons mentioned above, it could nevertheless be economically viable when taking into account the total picture (electricity + heat)."*

68. Elia explained to the CREG that, "for CHP, in order to model the fact that CHP have other revenues and drivers, CHP are modelled with a partial must-run constraint and a marginal price 20% lower than the most efficient CCGT for its revenue calculations." The running hours for a CHP is simulated to be above 7,000 hours, according to Elia. The CREG questions the way Elia simulates the economic viability of CHPs and the fact that Elia does not elaborate on these important elements in its study. Elia should consult in detail regarding this methodology and be much more transparent as to its approach with regard to costs, revenues, support schemes and exemptions.

69. In addition, Elia does not consider the support schemes for CHP, such as green certificates (in Wallonia and Brussels) and CHP certificates (in Flanders), since it relies purely on energy market revenues. But these support schemes are, by design, sufficient to compensate for any 'missing money'. So, if Elia concludes that CHP is not profitable, then the 20% lower marginal cost of CHP compared to the newest CCGT, does not sufficiently take into account the advantages of the support scheme.

70. With regard to small CHP, Elia should also take into account the effects of having a generation unit behind the meter where the production is used, as is explained in a subsection below.

71. These elements result in an underestimate of the economic viability of (new) CHP.

72. Furthermore, the impact on adequacy could be underestimated by Elia. For every 1 MW of electricity generation capacity, only 70% to 90% is assumed to be available, even during periods of scarcity. Elia assumes that heat demand will decrease the electricity output. In normal conditions, this assumption could hold, but when power prices spike up to 3,000 €/MWh and (much) higher, it is reasonable to assume that this effect will be minimal and that the maximal electricity output will be used. Moreover, this market reaction is already visible today, with a significant volume of CHPs reacting in real time on the imbalance tariff.

73. It should be noted that an increase of CHP-capacity will be very likely be a key policy in Germany to meet the climate targets while guaranteeing adequacy. Indeed, CHPs have several important advantages. They are technically very efficient, usefully using up to 90% of the primary energy, whereas even the most efficient new CCGTs achieve only 55-56%[25], wasting almost half of the primary energy. Secondly, CHPs already have a support scheme in place to compensate for missing money. No new support scheme needs to be designed. Thirdly, small CHP can be installed relatively quickly, with lead times of one year or less. Finally, this support scheme is targeted only to CHP. By applying a targeted support scheme, paying subsidies to capacity that has no missing money can be avoided, thereby avoiding over-subsidies to (existing) capacity already in-the-money. According to the results from Elia, existing gas-fired capacity less than 25 years old has no missing money. However, in a market-wide CRM, these capacities will also receive capacity payments, leading to this capacity receiving unnecessary subsidies and unnecessarily increasing the cost for consumers.

2.1.1.7. *<u>Foreign capacity</u>*

74. The economic viability check has only been made for Belgium, but not for the other countries in the EU. There is no reason why this should not be done for the other countries as well, because even if scarcity only occurs in Belgium, also other countries could face very high prices of 10,000 €/MWh or higher.

75. This is a consequence of the results of Elia's analysis. These results show that Belgium also has structural adequacy concerns even when there is still import capacity left for Belgium[26]. This is explained by the functioning of the day ahead market coupling in the European Internal Energy Market: price zones (countries) have to continue to export to other price zones (countries) as long as system adequacy can be maintained in the exporting country. This also means a country needs to continue exporting even if this leads to prices close to or as high as the market price cap (without curtailing demand in that country).

76. As such, if Belgium is confronted with adequacy concerns with very high market prices as a result and there is still import capacity for Belgium, as the case may be, then other countries will also face very high market prices. All the consequences for Belgium from having very high prices that was explained in the previous sections also apply for these countries.

77. This means that if there is still import capacity left on the interconnection for Belgium, adding extra capacity to address Belgian adequacy concerns is not limited to Belgium alone, but can also be found in France, Germany, the UK and the Netherlands, and even further afield.

78. Compared to the neighboring countries, Belgium's share in the total electricity consumption is around 6%. The potential to develop additional capacity, such as gas-fired power plants, demand response, back-up generation, (small) cogeneration and gas engines, is higher by a factor of around 10 compared to limiting the potential to Belgium alone.

79. The above is not anticipated by Elia in its study. Moreover, there is no data on demand response that will be available in other countries[27]. According to the latest information available (coming from the Penta-Lateral Energy Forum) the draft data shown in the figure below will be used for the Mid-

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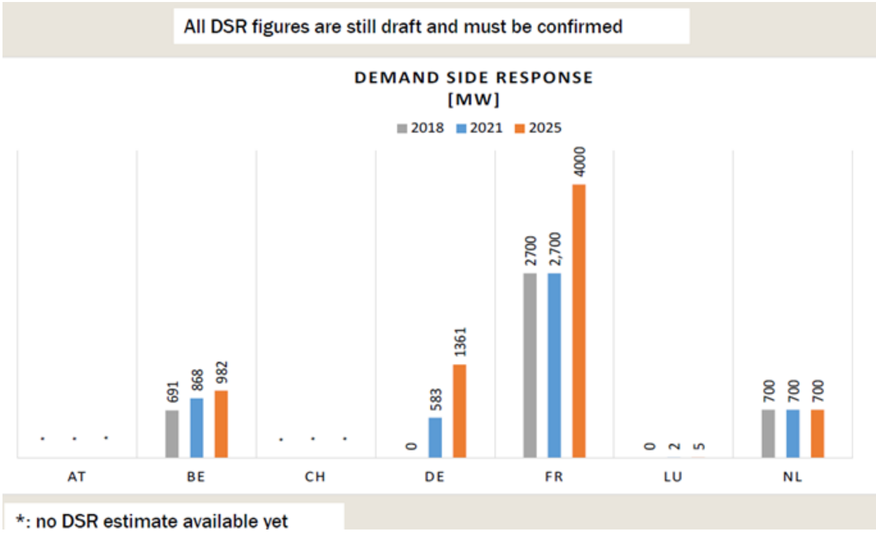
[25] The most efficient CCGTs have a nameplate efficiency of 62% based on the lower heating value of natural gas. In reality, the real efficiency according to the higher heating value of natural gas is about 10 percent less, resulting in an efficiency of 56%.

[26] The results in the Elia study show that during periods of scarcity, the imported energy is on average about 2,300 MW compared to a maximal import capacity of 7.500 MW. This means that additional capacity in foreign countries can significantly improve adequacy in Belgium.

[27] In its Medium Adequacy Forecast, Entso-E refers to a study indicating there would be a potential of 60 GW of demand response in Europe, of which 32 GW in the CWE region.

term Adequacy Forecast (MAF) 2019 by Entso-E. The CREG doubts that these figures fully take account of the removal of price caps for some countries. Up to 2025, no demand side response for Switzerland and Austria is considered, in the Netherlands the volume remains stable between 2018 and 2025 (700 MW). Taking into account the size of the electricity market in Germany, it is impossible to explain that the demand side response volume for Germany remains below the Belgian level until 2021 and only exceeds the Belgian level by about 400 MW by 2025.



80. According to the Clean Energy Package (CEP), the extra capacity in other countries should be anticipated by the Resource Adequacy Assessment (RAA), which is not the case. It is important to note that various types of capacity have short lead times, sometimes much shorter than one year.

81. Moreover, Elia assumes in its base scenario that 9 GW of gas-fired capacity will be mothballed. At the same time, Elia also takes the recent agreement of faster coal-phase out in Germany in the base scenario. It would be expected that with the accelerated phasing-out of coal in Germany, the mothballing of additional gas-fired capacity is highly unlikely, and so this mothballing of additional gas-fired capacity should not be in a base case scenario. Indeed, market-driven de-mothballing is already occurring, for example with the Claus C gas-fired unit (1,300 MW) in the Netherlands which is returning to the market. Additional de-mothballing should also be considered in the economic viability test, where de-mothballing should be assumed to have a very low investment cost.

82. In one sensitivity analysis, Elia takes into account the impact of "no mothballing" of additional gas-fired Europe (excluding Belgium), leading to a gap that is 700 MW smaller for Belgium. As already stated, this scenario should be included in the EU-base scenario via the economic viability test.

2.1.1.8. Generation "behind the meter"

83. The economic viability check does not consider the effects of having generation capacity "behind the meter". As the CEP supports self-consumption, this should clearly be taken into account.

84. In October 2016, CREG published a study[28] with an economic assessment of decentralized, dispatchable generation units, such as small CHPs, diesel and gas engines. These generation units were considered as behind the meter and with low lead times to install (a year or less).

[28] See CREG-study 1583 in Dutch: https://www.creg.be/sites/default/files/assets/Publications/Studies/F1583NL.pdf
See CREG-study 1583 in French: https://www.creg.be/sites/default/files/assets/Publications/Studies/F1583FR.pdf

85. The conclusion of the study is that new small CHPs are clearly profitable. New gas engines are also profitable, if the flexibility of a gas engine is also used to arbitrage between the day-ahead and the real time markets. A recent update of the analysis shows that market conditions have improved, making local generation units even more profitable than before.

86. An important aspect of the economic assessment is the fact that these units are behind the meter. When producers self-consume the electricity from their local generation units, they avoid paying part of the offtake tariffs and levies. This is an important driver of the profitability of these units. However, the Elia economic assessment does not take this into account.

2.1.1.9. WACC

87. Elia uses a WACC of 10%. If one assumes an investment is financed by 30% equity and 70% debt, with a loan cost of 4%, then a WACC of 10% implies a return on equity of 24%. This is extremely high. A WACC of 7% with the same conditions leads to a return on equity of 14%. A WACC of 5.2% with the same conditions leads to a return on equity of 8%[29].

88. Almost all types of capacities considered by Elia can be viewed as mature technologies. Some types of capacities require relatively low total investments, such as refurbishing existing gas-fired capacity, existing emergency generation and demand response, and/or have short lead times, such as emergency generation, demand response, gas and diesel engines and small CHP. Lower investment costs and/or short lead times should lower the investment risk.

89. According to the CREG, an economic assessment with a WACC not higher than 7% seems more appropriate for existing gas-fired capacity which requires refurbishment, for existing and new emergency generation, for demand response and for small CHP.

2.1.1.10. Conclusion

90. The above-mentioned analysis shows that the revenues for all types of capacities are underestimated due to the methodology used by Elia. The CREG is convinced that using a more proper methodology could have a major impact on the results for the economic viability.

Of course, all remarks regarding the economic assessment of Belgian capacities also apply for the economic assessment of foreign capacities.

2.1.2. Anticipating on the removal of price caps

91. The CEP requires that a RAA should anticipate the measures taken in the Implementation Plan. One of these measures is the removal of price caps[30]. This measure has already been decided by ACER: if the day ahead price reaches 60% of the price cap, then the price cap should be increased by 1,000 €/MWh. Given the current price cap of 3,000 €/MWh, this means a price of at least 1,800 €/MWh on the day ahead market would automatically lead to a price cap of 4,000 €/MWh. If the day ahead price subsequently reaches at least 2,400 €/MWh, the price is automatically set at 5,000 €/MWh, and so on. This measure, which also applies to the neighboring countries, should be integrated into the model.

[29] In a study for the CREG, consultant PWC took a WACC of 4% and a return on equity of 8% as an assumption for investing in small generation assets (< 8 MW) (see CREG-study n°1583).

[30] See Article 20.3.b of the Regulation

Each Monte-Carlo simulation, in which hourly prices are calculated, should take into account the previous occurrences of triggering 60% of the price cap.

92. As such, if Elia forecasts that Belgium would face a tight and even inadequate situation following the nuclear phase-out (and even already some years before), then this will lead to a much higher price cap than the current 3,000 €/MWh. Price caps of 10,000 €/MWh or higher will then easily be reached, leading to a higher economic value of existing capacity, but also to the development of additional capacity to the market.

93. Elia does take an increase of the market price cap into account in one sensitivity-analysis in its study. But by only considering the median (P50) revenue (see above), this only has a very small impact of +300 MW of capacity. Elia does not indicate what type of capacity is in the 300 MW. By considering the average revenues instead of the median (P50) revenue, much more capacity can be economically viable. Different types of capacity have different lead times. New CCGTs have lead times of several years and face high investment costs. However, there are various other types of capacities that can be developed, with short lead times (less than a year) and much lower investments costs.

94. The first type of capacity is obviously demand response. The potential of this capacity is very high[31]. Elia does not assess this capacity separately, but creates a new category, “market response”, where demand response is a subtype, along with generation behind the meter[32]. Elia is assessing that in 2020 Belgium would have 1.4 GW market response, which, according to Elia, would increase to 1.56 GW by 2025. However, last winter 2018-2019, Belgium faced the risk of inadequacy due to the sudden and unexpected unavailability of nuclear capacity. Several market parties said that they developed additional market response, such as demand response for several hundred MW, to address the shortfall in nuclear capacity, part of which was possible by actions undertaken by the Authorities. This capacity is not taken into account by Elia. The CREG-study 1950 on this period shows that there was always an additional capacity of at least 3.7 GW available for Belgium, even during the months when there was only one or two nuclear reactors available in Belgium[33].

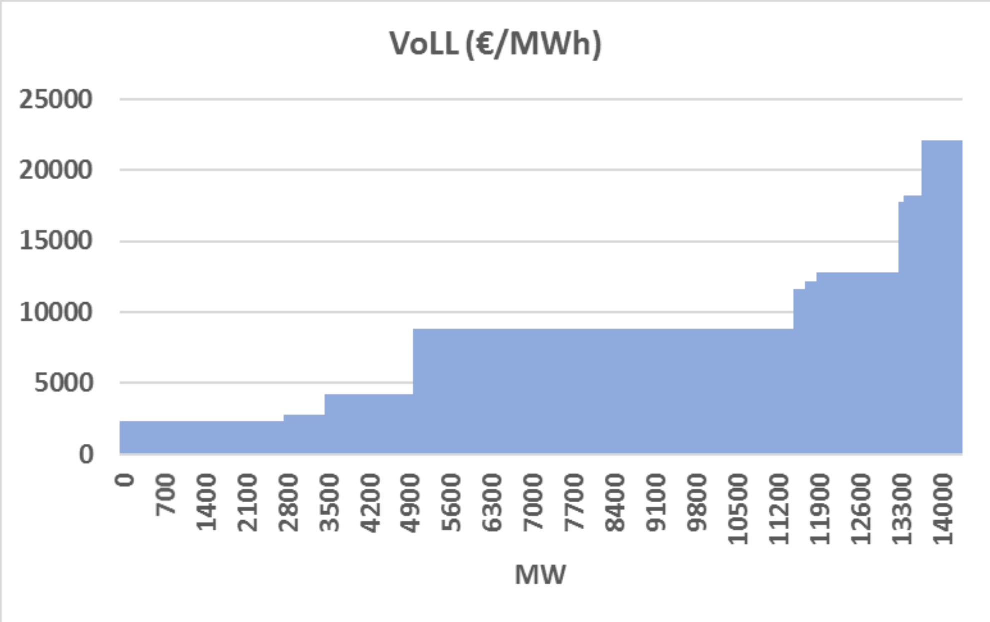
95. Furthermore, from a study by the Belgian Federal Planning Bureau, the value of lost load (VoLL), which can be viewed as the willingness to pay for electricity, was estimated[34]. The figure below shows the estimated average VoLL per category of consumers based on the study. Based on these data, it is clear that once prices would reach 10,000 €/MWh or more, many consumers would be willing to voluntarily decrease their consumption.

[31] In an analysis by the Belgian Federal Planning Bureau, the price-insensitive demand is considered to be 11% of the peak load (with an average VoLL of 23,300 €/MWh), implying that 89% of peak load is considered price-sensitive (with a VoLL < 15,000 €/MWh).

[32] This includes existing emergency generators on site of consumers, of which the potential can be very high. Based on a survey among all Belgian hospitals (response rate > 90%), the CREG concludes that there is 200 MW of emergency generators installed in Belgian hospitals alone. In addition, in the coming years, Elia will install around 100 MW of emergency generators, following the NC Emergency & Restoration.

[33] See CREG study 1950 on the market reaction to the unavailability of several nuclear reactors in Belgium in the period from October 2018 to February 2019.
See French version: https://www.creg.be/sites/default/files/assets/Publications/Studies/F1950FR.pdf
See Dutch version: https://www.creg.be/sites/default/files/assets/Publications/Studies/F1950NL.pdf

[34] See https://www.plan.be/admin/uploaded/201403170843050.WP_1403.pdf. The average VoLL was estimated at 8,300 €/MWh, later revised upwards to 10,300 €/MWh. The upward revision has not been published on the website of the Federal Planning Bureau.



96. When adding additional demand response in its iterative process of economic viability testing, Elia should consider different and increasing marginal costs of this capacity (5,000 to 10,000 €/MWh and even higher).

97. It is important to note that even consumers with (long-term) contracts at a fixed price continue to have an incentive for developing and selling their flexibility when prices are higher than their willingness to pay for electricity [35]. This is also true for residential consumers who have a digital meter. By 2025, around 25% of residential consumers in Belgium are expected to have such a meter.

98. On top of this, the CREG is aware of the existence of so-called “pass-through contracts” offered by suppliers, where market prices are directly passed through to consumers. More than 500 MW of consumption is already contracted via these pass-through contracts. This kind of flexibility cannot be measured or estimated by analyzing the aggregated day-ahead supply and demand curve on the power exchange, as is the methodology currently applied by Elia, since the market price passed through in these contracts is the imbalance tariff most of the time. This implies that a market player only has an incentive to react on the imbalance tariff, and not on the day price. Consequently, these capacities will not be present in the day ahead supply and demand curves, although they exist, leading to a structural underestimate of the available demand response.

99. The removal of price caps is not only already decided for Belgium, but for all countries in the EU. However, in its methodology, Elia does not take into account the impact of the removal of price caps in the rest of Europe. This should be the case, since the price caps will increase in all countries, even if there is only scarcity in one country. As such, when Elia assesses that Belgium will structurally be confronted with scarcity, in 2025 for example, then the price cap will increase in Belgium, but also in all other countries participating in the European market coupling.

[35] A “pass-through” contract can be set up as follows: a consumer and supplier agree that the supplier will deliver 10 MW for all hours of a certain period (baseload) at a fixed price, say 40 €/MWh; any deviation by the consumer from the 10 MW (in real time) will be settled against the imbalance tariff. So if for a given hour a consumer only takes off 6 MW when the positive imbalance price is 1.000 €/MWh, then the consumer will pay the supplier for that hour 10 MWh * 40 €/MWh = 400 € and receive from the supplier (1,000 €/MWh – 40 €/MWh) * 4 MWh = 3,840 €. By using their flexibility, the consumer is paid 3,460 € for that hour for consuming 6 MWh, even though the consumer has signed a fixed contract. Note that the imbalance risk from this customer for the supplier is reduced to zero. This kind of arrangement can also be set up with a market party, other than the supplier, by using the ‘transfer of energy’ scheme.

100. This implies that in all other countries in the EU, the price cap will be 10,000 €/MWh or even higher. Moreover, not only Belgium will face prices up to the price cap of 10,000 €/MWh or higher when confronted with adequacy issues, but other countries will also face the same very high or similar prices as Belgium, as explained above.

2.1.3. Taking available balancing reserves into account

101. Article 25 of the CEP states that when applying capacity mechanisms Member States shall have a reliability standard in place. A reliability standard shall indicate the necessary level of security of supply of the Member State in a transparent manner. The regulatory authority has to propose a reliability standard. This proposal is subject to approval by the Member State. The reliability standard shall be calculated using at least the value of lost load (VoLL) and the cost of new entry (CoNE) over a given timeframe and shall be expressed as "expected energy not served" (EENS) and "loss of load expectation" (LoLE).

102. The LoLE is the number of hours when there is involuntary load shedding. The EENS is the expected volume of electric energy that is involuntarily not consumed. This can only happen when consumers are forced to disconnect from the grid in real time.

103. A forced disconnection of consumers only happens after all available measures have been taken to avoid this forced disconnection, including the use of balancing reserves. This means that a RAA, which assesses whether the reliability standard has been met or not, should also take into account all the available measures to avoid involuntary load shedding, including the use of balancing reserves.

104. The balancing reserves that should be taken into account are the secondary reserves, now referred to as aFRR (automatic frequency restoration reserve), the tertiary reserves, now referred to as mFRR (manual frequency restoration reserve) and the inter-TSO reserve sharing with neighboring countries. These reserves are not available for the day-ahead and intraday market, but can be used in (or close to) real time if there is a risk there would be a forced disconnection of consumers (and causing "energy not served").

105. In its study, Elia assumes that it will procure at least 1,000 MW of domestic upward balancing reserves. Elia mentions the use of balancing reserves procured from decentral capacity for adequacy, but it seems that the other part of balancing reserves cannot be used by the model. Elia should clarify if and how Elia considers these balancing reserves in the adequacy analysis to avoid forced load disconnection. The CREG assumes that only balancing reserves with limited energy (about half of the reserves) can be used for adequacy. The CREG sees no reason why the other reserves, which could have a bigger impact on adequacy since they are not limited by energy, would not be used to avoid a forced load disconnection. In addition, Elia does not mention the use of reserves in other countries to avoid forced load disconnections in Belgium. Elia should use all available balancing reserves in its probabilistic calculations to calculate the EENS and the LoLE.

106. Academics have already analyzed how balancing reserves could efficiently be used in adequacy analysis. Researchers from KULeuven/EnergyVille and the EC JRC recently published an artice on this topic[36].

107. It should be clear that when all available balancing reserves are taken into account to calculate the LoLE and EENS, this can result in significant lower values of LoLE and/or EENS.

[36] See https://www.mech.kuleuven.be/en/tme/research/energy_environment/Pdf/wp-en2018-1

2.1.4. Strategic reserves

108. According to Article 21 of the CEP, if a RAA concludes that there are residual resource adequacy concerns, the Member State should also assess whether a capacity mechanism in the form of strategic reserve is capable of addressing the adequacy concerns. Where this is not the case, Member States may implement a different type of capacity mechanism. In Belgium there is currently a Strategic Reserve in place.

109. This is important, because Elia assumes that part of the existing capacity will leave the system (and not only the market) for economic reasons, adding to the adequacy concerns for Belgium. However, assuming there is a strategic reserve in place, all existing capacity can be put in the strategic reserve to avoid involuntary load shedding, lowering the LoLE and EENS.

110. On top of keeping the existing capacity from leaving the system, a Strategic Reserve (or other reserves that are kept out of the market) is also able to attract new capacities, such as demand response, but also generation and storage. The Belgian strategic reserve attracted a lot of demand response for the winter 2015-2016, up to 360 MW (from 95 MW for 2014-2015). In Germany, the winter reserves are being developed and will tender for 1,200 MW of new built capacity; 300 MW is already assigned to RWE by TenneT.

111. With regard to the use of strategic reserves, Article 22.2 of the CEP states that the design of strategic reserves needs to follow the requirement that where a capacity mechanism has been designed as a strategic reserve, the resources thereof are to be dispatched only if the transmission system operators are likely to exhaust their balancing resources to establish an equilibrium between demand and supply. This again is a clear indication that balancing reserves should also be used to avoid involuntary load shedding, lowering the LoLE and EENS.

2.1.5. Sharing of (strategic) reserves

112. Article 26.1 of the CEP states that mechanisms other than strategic reserves and where technically feasible, strategic reserves shall be open to direct cross-border participation of capacity providers located in another Member State, subject to certain conditions.

113. From the adequacy assessment, it follows that a lack of resource capacity in other countries prevents a larger export to Belgium, thereby limiting the contribution to the adequacy situation for Belgium. This implies that there is still import capacity available for Belgium. This is also clear by the sensitivity analysis in which Elia takes into account the "no mothballing" of gas-fired capacity in the neighboring countries (see above). The fact that this decreases the capacity shortage in Belgium estimated by Elia at 700 MW implies that additional capacity in a foreign country can improve the adequacy situation in Belgium. This is only possible if there is still import network capacity available to Belgium.

114. This also implies that reserves and additional capacity in Germany, Austria, France, the Netherlands or other countries can also help the adequacy situation in Belgium. In this regard, it is important to point to the so-called winter reserves in Germany. These reserves, currently about 6.6 GW, are primarily located in the South of Germany to stabilize the German grid. When there is a lot of wind and coal/lignite power generation in the North of Germany, the internal grid within Germany needs to be compensated by these grid reserves in the South. These reserves are kept out of the market. If Belgium wants to use these reserves, there could be a need for an agreement with those countries, depending on the regulation under which these reserves would be used.

115. Bundesnetzagentur, the German regulator, projected the need for the winter reserves in 2022-2023 at 10.6 GW, an increase with 4 GW[37].

116. When there is a lot of wind available in Germany and Europe, these winter reserves can be used. Resource adequacy concerns in Belgium during these periods are highly unlikely. In the opposite situation, when wind is very low, the winter reserves will probably not be used to stabilize the grid and can then be used for adequacy issues in Germany, but also in Belgium.

117. Elia does not take into account these vast reserves in Germany. Elia explains this to the CREG by referring to a lack of a framework for sharing these reserves. However, in the CEP, there is an obligation to open strategic reserves to foreign capacity if it is technically feasible. Given that there is a significant number of periods where import capacity is not the limiting factor, it should be clear that the large winter reserves in Germany could contribute to the adequacy situation in Belgium. Establishing a framework by 2025 for sharing (strategic) reserves is clearly feasible[38].

118. As previously stated, a TSO should use all its available measures before proceeding to a forced load disconnection (and causing an "energy not served"), including but not limited to all available balancing reserves. This follows directly from Article 21 of the NC Emergency and Restoration[39]. Moreover, a TSO can also request help from other TSOs when it expects to face an adequacy issue. These other TSOs need to make the unshared balancing bids available and are entitled to activate the available balancing energy, in order to provide the corresponding power to the requesting TSO and are entitled to request the assistance for active power from its balancing service providers and from any significant grid user (see Article 21 of NC ER).

119. Since this is established legislation, directly applicable in all Member States, Elia should take this into account when simulating the LoLE and the EENS. However, Elia only calculates the "market LoLE" and "market EENS", without taking all available balancing reserves and other measures in Belgium and other countries into account.

120. Finally, the risk-preparedness regulation, part of the CEP, states that "*In the event of an electricity crisis Member States should cooperate in a spirit of solidarity. In addition to that general rule, appropriate provision should be made for Member States to offer each other assistance in an electricity crisis. Such assistance should be based on agreed, coordinated measures set out in the risk-preparedness plans*"[40]. The CREG believes that sharing of strategic reserves is not only for reasons of solidarity but also economically an important measure. These measures can be implemented before the complete nuclear phase-out in Belgium by the end of 2025.

2.1.6. Various comments

121. In its key message, Elia states that a shortage of 3.9 GW is to be expected by the winter of 2025-2026, after the complete phasing out of nuclear capacity. This result is not based on the base case scenario, but on a 'low probability - high impact' sensitivity analysis in which France unexpectedly loses 3,6 GW of nuclear capacity. As a result, France cannot guarantee its security of supply, despite a CRM.

[37] See: https://www.bundesnetzagentur.de/EN/Areas/Energy/Companies/SecurityOfSupply/GridReserve/GridReserve_node.html
[38] In the past, there was already one generation unit located in a foreign country that participated in the Belgian strategic reserves, namely Twinerg in Esch-sur-Alzette in Grand-Duchy of Luxembourg. This generation unit was connected to the Elia grid.
[39] See NC ER: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:32017R2196
[40] See whereas 25 of the risk-preparedness Regulation: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=uriserv:OJ.L_.2019.158.01.0001.01.ENG&toc=OJ:L:2019:158:TOC

122. However, the base case scenario shows a shortage of 2.4 GW if the existing thermal capacity in the system can be maintained. It is important to note that several historical climate years were also taken into account in the base case scenario, including extreme events such as long periods of low wind and cold spells. Having an additional extreme scenario on top of this base case scenario is a too conservative approach in the CREG's opinion.

123. Elia assumes there is only 4.7 GW of gas-fired capacity in the market/system, leading to a derated capacity of 4.3 GW. According to CREG's calculations, 5 GW of capacity should be expected in the system, with also Vilvoorde[41] (265 MW), leading to a derated capacity of at least 4.5 GW.

124. Elia takes a de-rating of capacity into account due to the unavailability of the capacity. For thermal capacity, this is about 10%. So only 90% of the capacity is considered as available. On top of this de-rating, Elia uses a balancing reserve capacity of at least 1,000 MW to compensate unexpected outages. For the CREG this could be too conservative, especially since generation capacity is in principle not allowed to have its maintenance during winter periods, leading to a high availability of capacity during periods of potential scarcity.

125. Elia assumes that most capacity within market response has a limited energy. Only 10% has no limit on energy. 71% has a limit of 4 hours or less, while 19% has a limit of 8 hours. The CREG asked Elia to assess the adequacy assuming that the market response would be according to the needs. If longer periods of scarcity on a single day became more frequent, as seems to be the case, then the economic value of market response with no limit would also increase. This would be ideal for existing emergency generators. However, Elia did not follow this request without providing an explanation and kept the structure of its market response unchanged.

126. The nuclear capacity for the UK in Figure 2-39 does not appear to be correct. For 2030, there is only a capacity of 2.9 GW, whereas 3.2 GW of additional capacity is expected. Together with the 1.2 GW in Sizewell B, this would result in 4.4 GW of nuclear capacity.

127. Elia assumes that one third of nuclear capacity in Belgium is unavailable, based on the historical data from recent years. This seems a conservative approach, bearing in mind that much of the unavailability was due to the extension of the service life of three reactors and due to Doel 3 and Tihange 2 which are expected to close. In addition, when simulating the life time extension of Doel 4 and Tihange 3, Elia considers there is only one available, implying an unavailability of 50%.

128. Elia takes historical temperatures into account to simulate future conditions. With climate change, these temperatures are rising, possibly leading to fewer cold spells in the future. If this is confirmed for Belgium and Europe by meteorologists, Elia should take this effect into account.

129. The CREG has various others questions regarding the use of input data. Elia consulted on the use of these input data, a consultation the CREG views as insufficient. The CREG has explained this in a formal CREG-note 1901[42].

130. Finally and importantly, the CREG insists that Elia does all the necessary to make all models, methodologies and input-data from the Elia-study an open source application.

[41] Vilvoorde OCGT announced a temporary closure after winter 2019-2020.

[42] See French version: https://www.creg.be/sites/default/files/assets/Publications/Notes/Z1901FR.pdf
See Dutch version: https://www.creg.be/sites/default/files/assets/Publications/Notes/Z1901NL.pdf

2.2. RESULTS AND SENSITIVITIES

2.2.1. The main results: LoLE and EENS

131. Part of the results are shown in figure 4-2 in the report. In the base scenario, there is a gap of 6.7 GW of capacity to meet the reliability standards for Belgium. If all available capacity could be maintained in the system, whether in the market or in a strategic reserve, the gap narrows down to 2.4 GW.

132. Importantly, Elia gives no results on the loss of load expectation (LoLE) and the expected energy not served (EENS), the two indicators that are explicitly mentioned in the CEP as a reliability standard.

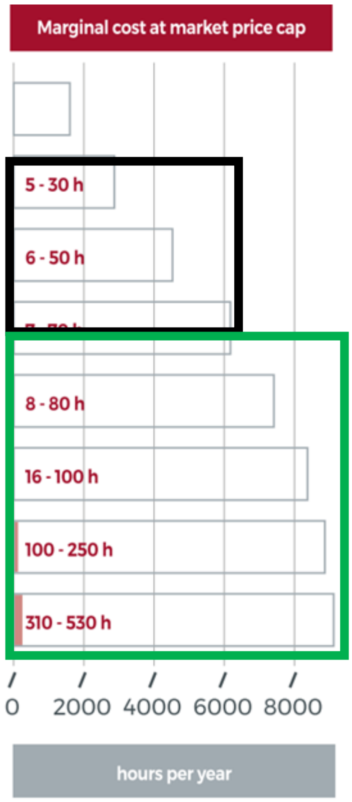
133. In figure 4-18, Elia does show two newly-created indicators, the so-called “market LOLE” and “market EENS”, meaning that Elia only takes capacity in the energy market into account and calculates the number of hours the market cannot meet demand and the energy not served by the market. With this approach, Elia disregards the market reaction in real time, e.g. the pass-through contracts (see above). Elia also disregards non-market-based measures. But before a consumer is forced to disconnect from the grid, European regulations impose that all measures should be taken to avoid this, including using balancing reserve capacity and other capacity such as strategic reserves.

134. This means that Elia’s newly-created indicators overestimate the true LOLE and EENS. Elia expects in the base scenario that the average “market LOLE” in 2025 will be 9.4 hours and the “market EENS” will be 23 GWh. This equates to 0.11% of the year Elia expects the market will not be able to meet demand in 2025, representing 0.027% of the total electric energy that is consumed in the year.

135. When calculating the “market LOLE” and the “market EENS”, Elia does not consider all existing units, as it considers that 1.7 GW of the 4.3 GW existing (mostly gas-fired) capacity will not be economically viable. In addition, Elia does not include the temporarily unavailable unit in Vilvoorde (265 MW).

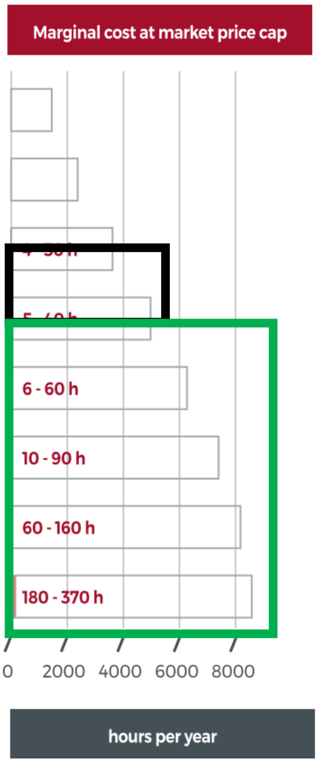
136. If Elia adhered to the CEP, it would also calculate the impact of maintaining the strategic reserves, with at least the 4.5 GW of existing capacity, including Vilvoorde. However, this information could be inferred from figure 4-43. The right part of that figure is shown below. The blocks show the capacity gap of 6.7 GW, without taking the existing gas-fired capacity into account. The red numbers show the number of hours this capacity is needed to meet the adequacy requirements (average and P95). On this figure, the CREG added the existing capacity of 4.5 GW that would be in the system if all this capacity would be maintained (green rectangle).

137. The remaining gap of 2.2 GW in 2025 is shown with the black rectangle. On average, this capacity is only needed for about 5-6 hours to meet the adequacy requirement of an average 3 hours LoLE. This results in an EENS of around 13 GWh, or 0.015 % of the total electric energy consumed in a year.



138. But even this EENS of 15 GWh is not the true EENS. For this, Elia should also take into account all available balancing reserves. These balancing reserves are considered to be at least 1,000 MW. The impact of taking the balancing reserves into account is not straightforward, because these reserves consist partly of demand response with limited energy. In addition, it is likely that part or all of the balancing reserve is sometimes needed to compensate unexpected events. This should be simulated with a probabilistic approach. As explained above, researchers have already proposed a methodology to take balancing reserves into account. But it is clear that taking into account the balancing reserves will lower the LoLE and EENS and the capacity gap.

139. As previously stated, the resource adequacy concerns decrease from 2025 to 2028. If all existing capacity can be maintained in the system, the gap decreases by 1.4 GW to 0.8 GW and the average LoLE above the reliability standard also decreases slightly to 4-5 hours. This can be seen from the figure below taken from the Elia study (figure 6-24). Again, the CREG added the existing capacity of 4.5 GW that would be in the system if all this capacity was maintained (green rectangle). Now the EENS is 4 GWh or less.



140. To conclude, Elia does not calculate the true LoLE and true EENS. From the analysis above, the true EENS in 2025, taking balancing reserves and out-of-market capacity into account, can be expected to evolve to 0.01% of total electric energy consumed, meaning that around 99.99% of power demand can be met, even if we were to accept all other assumptions that Elia makes for its base scenario. For 2028, the EENS would even be significantly lower than 0.01%.

141. Since the reliability parameter has not yet been approved under the CEP, Elia should simulate sensitivities on different reliability standards.

2.2.2. Situation in other countries

142. The CREG asked Elia to provide detailed information on the import capacity if Belgium would not be able to meet the adequacy requirements. CREG would like to know whether imports to Belgium are limited by the network capacity or because the resources in other countries are insufficient (or both). Elia does not provide this information clearly.

143. Again, however, this information can be partly inferred from information Elia does publish, more specifically in figure 4-11. From this figure, the CREG infers that Belgium can import around 2,300 MW on average if it is facing a market shortage. The CREG asks Elia to publish much more detailed information on the import capacity during periods of scarcity.

2.2.3. Cost of market-wide CRM vs Strategic Reserves

144. For the cost of the market-wide CRM, Elia refers to the base case cost of 350 M€/year from the PWC study (March 2018). Elia applies a range of 300-500 M€/year and concludes that this represents a cost of 3-5 €/MWh for the consumed energy, implying a total consumption of 100 TWh.

145. It should be noted that the cost range of the PWC study does not seem to take into account the additional need for capacity, as simulated by Elia in its recent study. This additional need would also lead to a higher cost of the CRM. The CREG has also referred to the cost of 350 M€/year as being a discounted cost with a discount rate of 8.5%. Using the nominal cost, this cost increases to 614 M€/year. With additional assumptions, the CREG comes to a nominal cost range of 614 to 940 M€/year.

146. If the nominal costs are used and the total expected consumption by Elia is 87 TWh (which is used to calculate the cost of a strategic reserve), this results in a cost of 7 to 11 €/MWh, much higher than the range of 3-5 €/MWh Elia suggests.

147. For the Strategic Reserve, Elia does update the cost for the additional need for capacity. Elia claims that Belgium would need 4.2 GW of strategic reserves in 2025, almost all of which would be new built at a cost of 50 €/kW, leading to total cost of 210 M€/year. This seems to be a nominal cost, and not discounted by 8.5%. This time, Elia uses a total consumption of 87 TWh (and not 100 TWh), leading to a cost for the Belgian consumer of 2.4 €/MWh.

148. This is not the first time Elia calls for a strategic reserve of several GW. The CREG would like to recall the adequacy assessment made by Elia for the winter 2015-2016, when Elia assessed a need of 3.5 GW of strategic reserve[43]. Eventually, Elia could contract about 1.5 GW of strategic reserves. During that winter, there was no adequacy issue and the strategic reserves were never close to being activated. In addition, before last winter, Elia warned of a high risk of scarcity. As a consequence, several measures were taken to improve the flow-based market coupling, thereby increasing the import capacity to Belgium. The authorities and the market also reacted quickly, adding more than 1.2 GW of domestic capacity in the space of a few months. In a recent report, the CREG concludes that there was always a capacity margin of at least 3.7 GW available for Belgium, even during the months there was only one or two nuclear reactors available in Belgium[44].

149. If Elia were to make a more effective resource adequacy assessment, taking into account the remarks in this document, the CREG is convinced that the need for strategic reserves would be much lower, perhaps even non-existent. Moreover, even if Belgium needed a strategic reserve with contracts signed after 31 December 2019, it should be open to foreign capacity, if technically feasible. This would mean that capacity in the German winter-reserve would be able to bid for the Belgian strategic reserve, increasing competition and consequently lowering the cost for the Belgian consumer. This could then result in costs significantly lower than the current 36 €/kW that Elia uses as a reference cost for existing capacity and much lower than the 50 €/kW used as a reference for new capacity in the strategic reserve.

[43] https://economie.fgov.be/sites/default/files/Files/Energy/Analyse-Elia-2015-2016-NL.pdf

[44] See CREG study 1950 on the market reaction to the unavailability of several nuclear reactors in Belgium in the period from October 2018 to February 2019.
See French version: https://www.creg.be/sites/default/files/assets/Publications/Studies/F1950FR.pdf
See Dutch version: https://www.creg.be/sites/default/files/assets/Publications/Studies/F1950NL.pdf

3. CONCLUSION

150. The CREG has analyzed the resource adequacy assessment published by Elia in June 2019. The analysis was made in the light of the new Regulation on the Internal Energy Market, which is part of the Clean Energy Package. This new legislation was adopted on 22 May 2019 and came into force on 4 July 2019. The Regulation is directly applicable in all Member States.

151. The CREG concludes that the resource adequacy assessment published by Elia in June 2019 can be improved on many aspects, ranging from the formal procedures to the methodology and assumptions and sensitivities that are applied. Moreover, these improvements would make the study also better aligned with the criteria set out in the Regulation. Finally, with the improvements which are explained in this document, the CREG asks Elia to make an additional simulation taking into account the different comments and suggestions made in this study. This would give a more complete and nuanced view on the adequacy issue for the upcoming years.

152. In the case Belgium would use the resource adequacy assessment published by Elia in June 2019 to justify the need for a market-wide CRM, CREG concludes this must be confirmed by the European Commission whether this is compliant with the European Clean Energy Package.

153. In order to address the concerns around security of supply as efficiently as possible, it is best that, besides the development of a market-wide CRM, the option of a Strategic Reserve (adjusted as necessary) should be kept open. A Strategic Reserve, which is an out-of-market reserve, is already in place in Belgium and was already approved by the European Commission for a five-year period that could be extended if necessary.

For the Commission for Electricity and Gas Regulation:

Andreas TIREZ	Koen LOCQUET
Director	Acting President of the Board of Directors