RÉPONSE DE LA CREG À LA CONSULTATION D'ELIA CRM DESIGN NOTES (PART 1)

Design note on intermediate price cap
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List of definitions

NON CONFIDENTIEL

TABLE DES MATIERES

1 REMARQUES RELATIVES A LA CONSULTATION

1. Le *design* d'un CRM est composé de multiples éléments qui interagissent les uns avec les autres. Les commentaires ci-dessous ne portent que sur l'analyse des *design notes* soumises par Elia à la consultation publique le 13 septembre 2019 relatives à deux éléments du *design*. Or seule une analyse de l'ensemble du dispositif permettra la formulation de commentaires complets. De plus, ces *design notes* présentent une première ébauche des principes qui devront être complétés et détaillée pour finalement être transposé dans des textes définitifs (arrêtés royaux et règles de fonctionnement). La CREG se réserve donc le droit de formuler ultérieurement d'autres commentaires sur ces éléments du *design*, après analyse de l'ensemble des éléments, mais également lors de la lecture de la proposition d'arrêté royal accompagné du commentaire des articles ainsi que de lors de l'analyse des *market rules* pour lesquelles la CREG dispose d'une compétence d'approbation.

2. La présente réaction de la CREG est le résultat d'une analyse sur base de la compréhension actuelle du mécanisme et de la vision actuelle de la CREG sur le CRM. Il est évident que, suite à des réflexions en cours sur d'autres éléments du *design*, cette vision pourrait encore évoluer. Dès lors, la CREG est d'avis que les commentaires émis après que tous les documents relatif au design du CRM aient été portée à la connaissance des acteurs du marché devraient pouvoir être pris en compte.

2 REMARQUES COMMUNES AUX DEUX DESIGN NOTES

3. Tant la détermination des *AMT hours* que l'estimation des revenus utilisés pour le calcul de *l'intermediate price cap* reposent sur un modèle de simulation employé par Elia. Il est donc essentiel que les hypothèses utilisées ainsi que le choix des scénarios soient transparentes, motivées et consultées, que la méthodologie de calcul soit robuste, consultée, et réponde aux prescrits des articles 23 et 24 du règlement européen 2019/943[1]. A cet égard, la CREG rappelle qu'elle a émis dans son étude 1957[2] des remarques de fond relatives à la méthodologie utilisée par Elia pour élaborer son rapport '*Adequacy and flexibility 2020-2030'* ; ces remarques valent également dans le cadre des design notes soumises à la consultation.

[1] Règlement (UE) 2019/943 2019/943 du Parlement européen et du Conseil du 5 juin 2019 sur le marché intérieur de l'électricité

[2] Study (F)1957 - Analysis by the CREG of the Elia study 'Adequacy and flexibility study for Belgium 2020 – 2030' – 11 July 2019

3 DESIGN NOTE ON INTERMEDIATE PRICE CAP

3.1 REMARQUES PRELIMINAIRES

4. La *design note* relative à *l'intermediate price cap*, reprend, dans une annexe, une proposition de principes devant servir de base à la rédaction d'un arrêté royal. La CREG rappelle que l'article 7*undecies*, § 2, de la loi électricité charge le gestionnaire du réseau d'établir une proposition de méthode devant permettre d'établir (i) un rapport contenant un calcul du volume et (ii) un rapport contenant une proposition de paramètres nécessaires à l'organisation des enchères[3], et que les plafonds de prix, sujet de la design note, ne constitue qu'un des paramètres de la mise aux enchères. L'article 7*undecies*, § 2, prévoit que la proposition d'arrêté royal doit « *être formulée après consultation des acteurs du marché* ». Pour se conformer à la disposition légale précitée, Elia devrait dès lors selon la CREG organiser une seconde consultation publique portant sur une proposition d'arrêté royal en bonne et due forme, contenant la méthode relative à la détermination de l'ensemble des paramètres des enchères[4] et du volume nécessaire.

3.2 DESIGN

5. Pt 2.1. : L'*intermediate price cap* (IPC) s'appliquerait à toutes les CMU éligibles à ou optant pour un contrat de capacité d'un an. La CREG soutient ce principe lorsqu'un point de fourniture classé dans une catégorie de capacité donnant droit à un contrat pluriannuel opte pour intégrer un portefeuille agrégé contenant des points de livraison éligibles pour un contrat annuel. Il serait en effet discriminatoire de permettre à cette CMU de soumettre une offre supérieure à l'IPC du fait de la présence de ce point. En revanche, si la CMU qui opte pour un contrat d'un an se compose d'un seul point de fourniture classé dans une catégorie de capacité donnant droit à un contrat pluriannuel, il pourrait être envisagé de l'exempter de l'IPC.

6. Méthode de calibration :

- La méthode de détermination de l'IPC est insuffisamment détaillée. Des développements ultérieurs devront préciser, entre autres :
  - les critères de choix de la *short list* des classes de technologies existantes ;
  - le mode de calcul de coûts et revenus par classe de technologie ;
  - la méthodologie de modélisation, le choix des hypothèses et du scénario de référence qui devrait selon la CREG ne pas être cohérent avec le(s) scénario(s) utilisé(s), mais identique ;
  - la méthode de détermination des revenus des marchés du balancing et des services auxiliaires associés à chaque classe de technologie ;

[3] À l'exception des paramètres de détermination du volume à contracter dans le cadre des enchères, dont la courbe de demande, que le Règlement 2019/943 sur le marché intérieur de l'électricité charge l'autorité nationale de régulation de proposer à l'autorité compétente.

[4] Voy. la note précédente.

- Les conditions et la périodicité de la révision de la *short list* des technologies existantes devraient être précisées. Une actualisation annuelle des revenus devrait aller de pair avec l'actualisation annuelle de certains coûts (projection des coûts des combustibles, tarifs d'utilisation des réseaux,…).
- Si la détermination de l'IPC est du ressort du gestionnaire du réseau, la méthode de détermination du *missing money* employée devra être cohérente avec la méthode utilisée par la CREG pour la détermination des paramètres du volume à contracter. Or, pour les raisons indiquées dans son étude 1957, la CREG estime que la médiane du revenu est de nature à sous-estimer les revenus futurs sur les marchés de l'énergie et donc à fixer l'IPC à un niveau trop élevé, ce qui ne permettrait pas d'atteindre l'objectif de limitation de la rente inframarginale des capacités existantes sur le marché de la capacité. La CREG estime donc que le P50 devrait être remplacé par la moyenne des revenus. La motivation détaillé de la CREG à ce propos est reprise en annexe et fait partie intégrante de la réaction de la CREG à cette consultation publique.
- Le choix de l'expert indépendant et son rôle devraient être mieux définis.

4 DESIGN NOTE ON THE AVAILABILITY REQUIREMENTS AND PENALTIES

Proposal 1 & 2 :

7. Sur le système proposé par Elia, qui repose sur un contrôle de la disponibilité des capacités contractées pendant un nombre limité d'heures pendant lesquelles le prix de marché DAM dépasse un seuil, la CREG émet les observations suivantes :

- le choix du marché DA devrait être renforcé par la démonstration d'une corrélation importante observée par le passé entre ce prix de marché et les périodes de *near scarcity* ;
- de façon à assurer la disponibilité des capacités quand le système en a réellement besoin (objectif d'adéquation), Elia devrait également pouvoir contrôler la disponibilité des capacités à chaque fois qu'elle identifie un '*technical trigger*' similaire à celui mis en place dans le cadre de la réserve stratégique, après envoi d'un signal par Elia.

8. La formulation laisse supposer que le contrôle de la disponibilité ne sera réalisé que lors des AMT moments définis comme une succession d'AMT hours consécutives. Est-ce l'intention ?

Calibration de *l'AMT price – proposal 6*

9. Elia doit être transparente sur le choix du scénario. Ce scénario (ou ces scénarios) doit être le scénario choisi pour déterminer le volume de capacité à contracter lors de l'enchère et non simplement un scénario '*consistent with the one(s) determined to calibrate the volume to be procured through the CRM*'.

10. Le choix des price duration curves devrait être motivé. Elia donne à titre d'exemple P10, P50 et P90 pour déterminer les années mild year, expected et worst case. La CREG insiste sur le fait qu'un

choix clair devrait être fait d'une façon motivée. L'information disponible dans la design note ne permet pas aux acteurs de réagir sur ces choix d'une manière fondée.

11. Un contrôle de la pertinence des résultats de la simulation par rapport :

12. aux prix forward de l'année de livraison (= anticipation du prix DA par les acteurs du marché) devrait être réalisé ex ante ;

13. aux prix DA réellement observés devrait être prévu au terme de chaque année de façon à évaluer la méthode mise en place.

<u>Contrôle</u>

14. Elia propose de limiter les contrôles aux AMT hours (estimées entre 20 et 100 heures par an). Ceci signifie qu'un évènement survenu en début d'année pendant 100 h priverait Elia de tout contrôle pendant le reste de l'année. De même, si le prix AMT n'est jamais atteint, Elia ne sera pas en mesure d'effectuer un contrôle. Un dispositif additionnel devrait être prévu pour pallier ce type de situation de façon à maintenir un risque d'exposition à des pénalités pour non disponibilité.

15. Un rapport de monitoring trimestriel devrait être transmis par Elia à la CREG et à la contrepartie contractuelle.

<u>Obligated capacities</u>

<u>Proposal 7</u>

16. Au point 3.2., Elia traite du problème des *energy constraint CMU*. D'autres capacités ont un nombre d'heures de fonctionnement annuel limité, par exemple, par les normes d'émission. Comment ces limitations sont-elles prises en compte lors du contrôle de la disponibilité ?

17. Pt 3.2.3. - SLA : Pour quelle raison les activations sont-elles limitées à une par jour ?

<u>Proposal 9</u>

Available capacity

18. L'exactitude du tableau 5 devrait être vérifiée.

Pénalités

19. Si, conformément à l'article 7*undecies*, § 8, de la loi électricité, il appartient effectivement au gestionnaire du réseau de proposer les règles de fonctionnement du mécanisme de capacité, dont « *les obligations de disponibilité et les pénalités en cas de manquement à ces obligations* », le contrat de capacité est quant à lui signé par le fournisseur de capacité avec la contrepartie contractuelle (art. 7*undecies*, § 7, al. 1er). Cette contrepartie contractuelle doit encore être désignée par le Roi (art. 7*quaterdecies*). L'article 7*undecies*, § 7, prévoit que le contrat de capacité « *décrit les obligations du fournisseur de capacité, notamment l'obligation de disponibilité* ».
Il résulte de ce qui précède que si les règles de fonctionnement doivent bien contenir les pénalités en cas d'indisponibilité, il appartient à la contrepartie contractuelle d'appliquer ces pénalités. Or, la design note (*proposals* 18, 20 & 21) prévoit expressément que les pénalités sont appliquées par Elia, ce qui semble contraire à la loi, tant qu'Elia n'aura pas été désignée comme contrepartie contractuelle.

20. Il semble illogique que la pénalité diminue lorsque l'*unavailability period* s'allonge.

21. Le facteur de pénalité devrait être supérieur à 1 pour les indisponibilités non prévues de façon à inciter l'annonce des indisponibilités.

22. De façon à ce que la participation au CRM ne soit pas une option gratuite, le *stop-loss limit* devrait être supérieur à la rémunération annuelle de la capacité.

5 LIST OF DEFINITIONS

23. Une liste de définitions communes Elia – CREG – SPF devra être élaborée. Pour ce qui concerne les seuils et critères d'investissement, les définitions devront être reprises de la proposition d'arrêté royal élaborée par la CREG.

24. Les définitions de '*capacity contract duration*', '*Capacity Market Unit*', '*reference power*', *'service'* devraient être clarifiées.

25. Quelle est l'utilité de la définition de *Demand side unit* (DSU) ?

26. Les définitions de capacités existantes et nouvelles (« *New Capacity* » and « *Existing Capacity* ») devraient plus clairement spécifier le moment de référence. Afin d'éviter des discussions, il semble que les termes « already » and « not yet » dans ces définitions devraient être liés à un moment défini de manière précise.

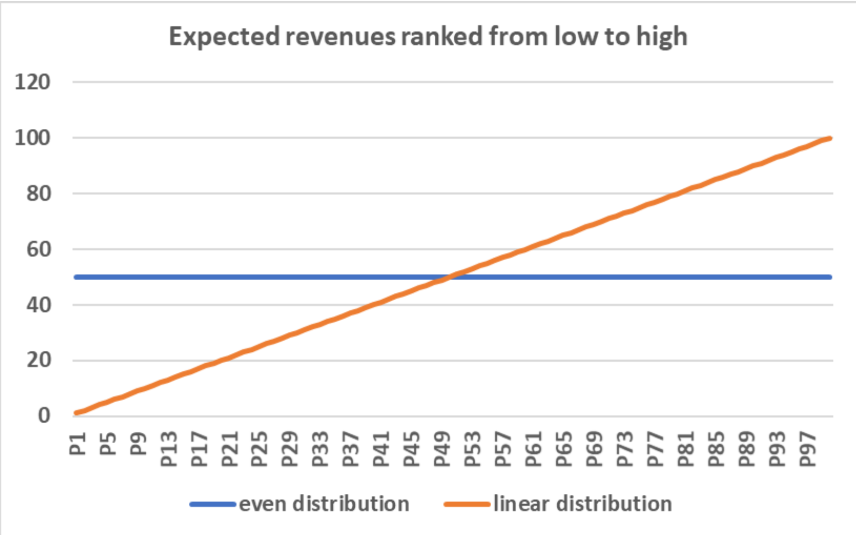
ANNEXE : extrait de l'étude 1957 de la CREG

2.1.1.3. Use of median (P50) revenues

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.

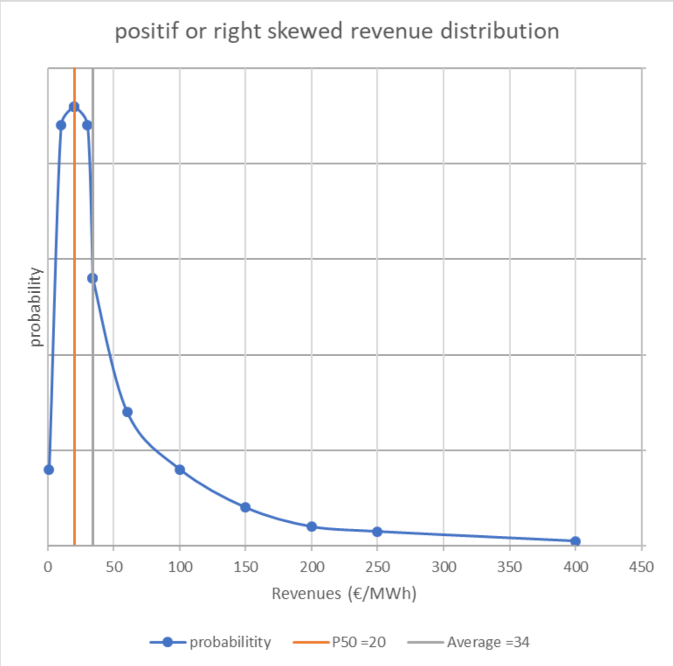
31. Elia uses a probabilistic approach, simulating yearly (Monte Carlo years) revenues according to several hundreds of different generation patterns of renewables and forced outages. It ranks these Monte Carlo years from low to high revenues. For the economic viability check of a certain type of capacity, 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.

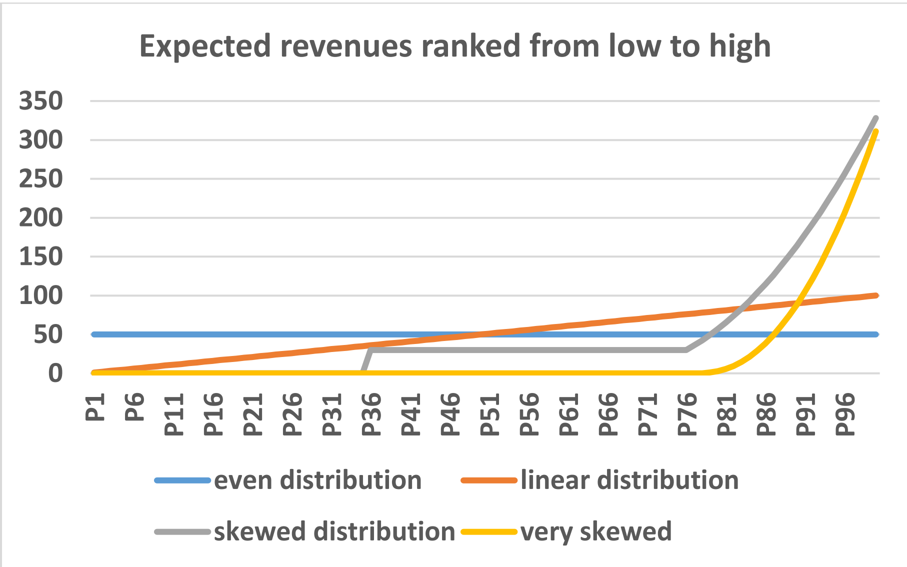


33. However, the revenues in the power sector are far from evenly or linearly distributed; they are highly skewed. This is all the more so when there are years when scarcity could occur, leading to prices reaching the market price cap.

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[5].

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[6]. 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.

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[7]). 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)[8], 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

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[5] 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.

[6] 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.

[7] 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.

[8] 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.

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 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[9].

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

[9] 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.

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[10]. 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.

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[11].

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[12]. 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

[10] 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.

[11] 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.

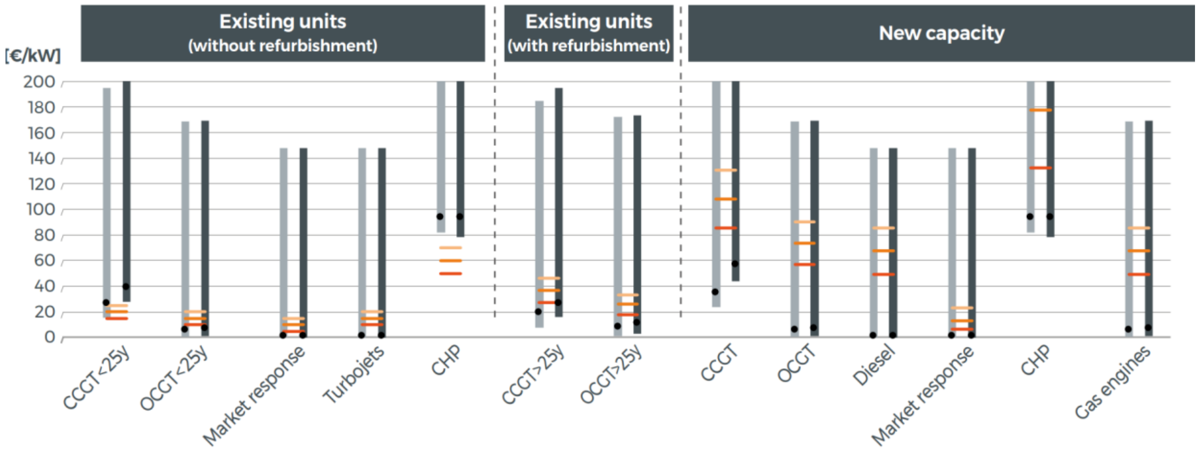
[12] Note that in a EOM with strategic reserves, load shedding can only occur when all balancing reserves, SR and other measures are exhausted. Load shedding will then only occur when there is a large shortage with BRPs.

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[13]. 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 CO2; 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.



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

[13] 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.

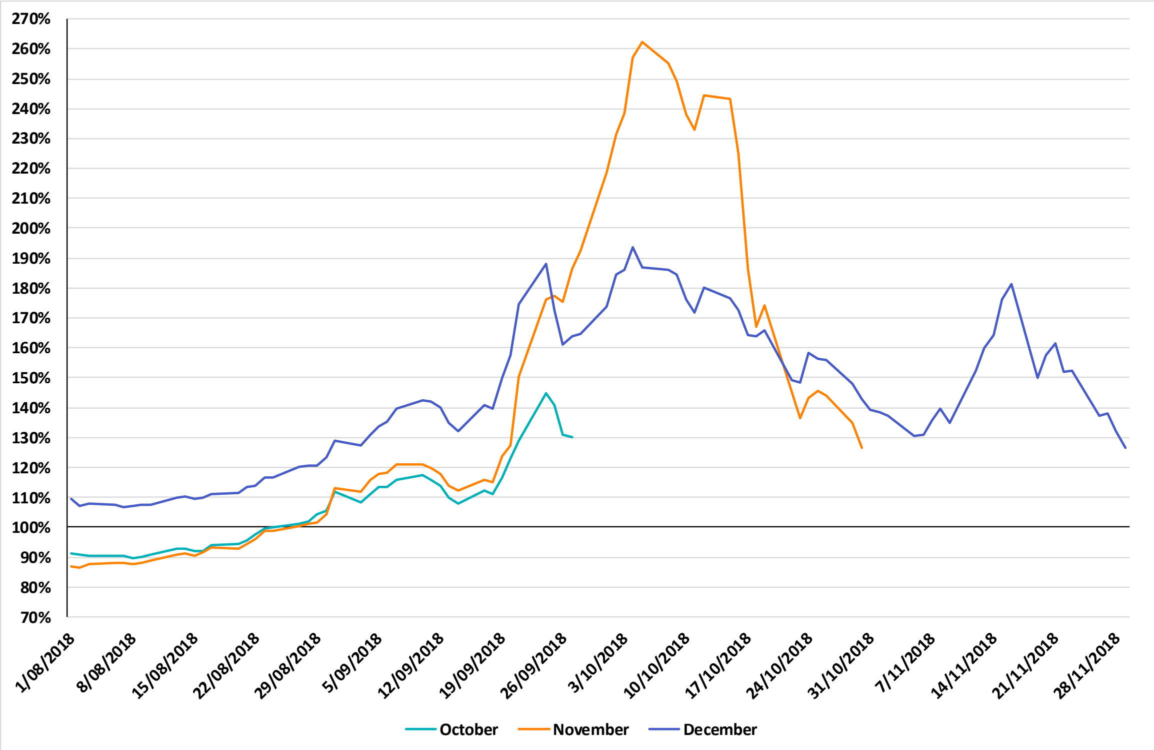
bankrupt a BRP/supplier with a shortage. On top of this, the market response has a low lead time of less than one year and sometimes just a few months (see below).

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.

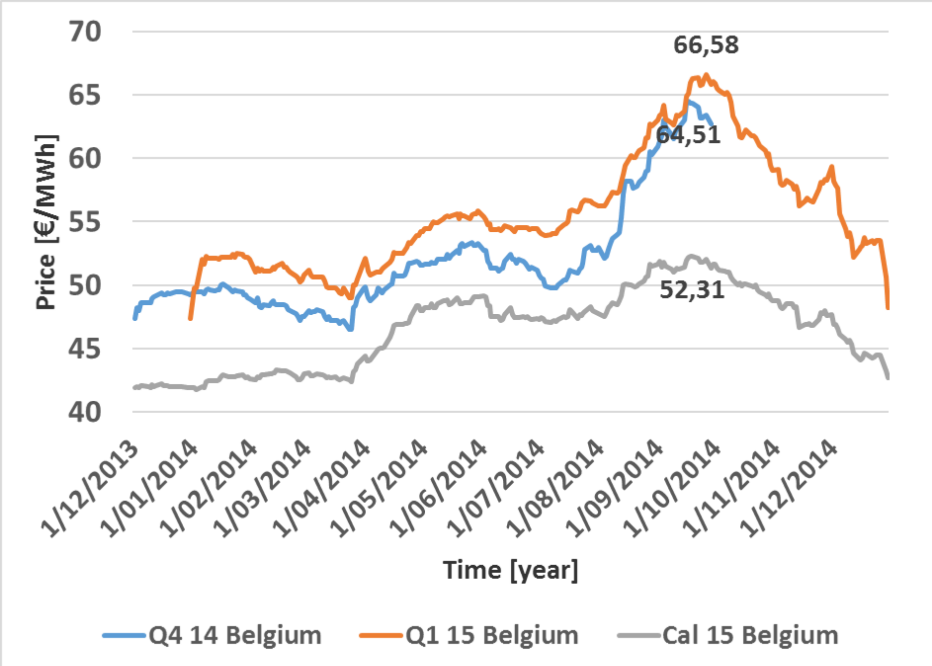
56. By only considering the median (P50) inframarginal rent, increasing or removing market price caps have no significant impact on security of supply. This goes against the logic of why the European legislator imposes the removal of price caps. Indeed, whereas (24) of the Regulation on the internal 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.