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COMMISSION DE REGULATION
DE L'ELECTRICITE ET DU GAZ

DECISION FINALE

(B)121115-CDC-1200

relative à la

'Méthode de répartition des capacités entre les différents horizons de temps sur la liaison entre la Belgique et la France' et la liaison entre la Belgique et les Pays-Bas

prise en application de l'article 23, §2, deuxième alinéa, 9°, de la loi du 29 avril 1999 relative à l'organisation du marché de l'électricité et des articles 180, §2 et 183, §2 de l'arrêté royal du 19 décembre 2002 établissant un règlement technique pour la gestion du réseau de transport de l'électricité et l'accès à celui-ci

le 15 novembre 2012

INTRODUCTION

Sur la base des articles 180, §2 et 183, §2 de l'arrêté royal du 19 décembre 2002 établissant un règlement technique pour la gestion du réseau de transport d'électricité et l'accès à celui-ci (ci-après : le règlement technique), la COMMISSION DE REGULATION DE L'ELECTRICITE ET DU GAZ (CREG) examine ci-après la proposition de la S.A. Elia System Operator (ci-après : Elia) relative à la "méthode de répartition des capacités entre les différents horizons de temps sur la liaison entre la Belgique et la France".

L'article 180, §2, du règlement technique prévoit que les méthodes de gestion de la congestion, ainsi que les règles de sécurité, sont notifiées par le gestionnaire du réseau à la CREG pour approbation.

L'article 183, §2, du règlement technique prévoit que les méthodes d'allocation aux responsables de l'accès de la capacité disponible pour les échanges d'énergie avec les réseaux étrangers, sont notifiées par le gestionnaire du réseau à la CREG pour approbation.

Le paragraphe 2.6 de l'annexe I du règlement prévoit que la structure d'attribution de capacité entre les différents horizons de temps est évaluée par les autorités de régulation respectives.

La proposition relative aux règles de répartition de la capacité entre les différents horizons de temps (à savoir, année, mois et jour) à partir de 2013 (ci-après : la proposition de répartition à partir de 2013) a été envoyée par Elia par lettre du 1er octobre 2012 à la CREG (et a été reçue par la CREG le 2 octobre 2012). Le dossier introduit par Elia se compose des documents suivants : la proposition d'Elia et RTE relative à la répartition de la capacité entre les différents horizons de temps sur la liaison Belgique-France à partir de 2013 ; un document d'analyse "France-Belgium Interconnection, allocation and utilisation of capacities: Observations & analyses 2011-2012" (ci-après : le document d'analyse) ; la répartition des capacités BE-NL.

La présente décision est organisée en quatre parties. La première partie est consacrée au cadre légal. La deuxième partie expose les antécédents de la décision. La troisième partie analyse les modifications proposées aux méthodes de gestion des congestions et d'attribution de capacité à la frontière belgo-française. La quatrième partie comporte la décision en tant que telle.

Une copie de la proposition des gestionnaires de réseau relative à la répartition de la capacité à partir de l'année 2013, ainsi qu'un document d'analyse sont annexés à la présente décision.

La présente décision a été adoptée par le Comité de direction de la CREG en sa séance du 15 novembre 2012.

I. CADRE LEGAL

I.1. Directive 2009/72/CE du Parlement européen et du Conseil du 13 juillet 2009 concernant des règles communes pour le marché intérieur de l'électricité et abrogeant la Directive 2003/54/CE

1. La Directive 2009/72/CE du Parlement européen et du Conseil du 13 juillet 2009 concernant des règles communes pour le marché intérieur de l'électricité et abrogeant la Directive 2003/54/CE (ci-après : la Directive 2009/72/CE) impose dans son article 12. f) une obligation générale selon laquelle le gestionnaire de réseau est tenu de garantir la non-discrimination entre utilisateurs ou catégories d'utilisateurs du réseau, notamment en faveur de ses entreprises liées.

La directive 2009/72/CE insiste particulièrement sur le principe de l'accès non discriminatoire au réseau de transport en son article 32.1 qui dispose que les Etats membres veillent à ce que soit mis en place, pour tous les clients éligibles, un système d'accès des tiers aux réseaux de transport et de distribution. Ce système, fondé sur des tarifs publiés, doit être appliqué objectivement et sans discrimination entre les utilisateurs du réseau.

L'article 32.2 de la directive 2009/72/CE précise notamment que le gestionnaire de réseau de transport peut refuser l'accès s'il ne dispose pas de la capacité nécessaire.

L'article 37.6.c) de la directive 2009/72/CE a trait aux tâches et aux compétences des autorités de régulation et prévoit qu'elles sont compétentes pour fixer ou approuver, suffisamment à l'avance avant leur entrée en vigueur, au moins les méthodes utilisées pour calculer ou établir les conditions d'accès aux infrastructures transfrontalières, y compris les procédures d'attribution des capacités et de gestion de la congestion.

L'article 37.9 de la directive 2009/72/CE prévoit que les autorités de régulation surveillent la gestion de la congestion des réseaux nationaux d'électricité, y compris des interconnexions, et la mise en œuvre des règles de gestion de la congestion et que, à cet effet, les gestionnaires de réseau de transport ou les opérateurs du marché soumettent leurs règles de gestion de la congestion, y compris l'attribution de capacités, aux autorités de régulation nationales. Les autorités de régulation nationales peuvent demander la modification de ces règles.

L'article 38.2 c) de la directive 2009/72/CE prévoit que les autorités de régulation coopèrent au moins à l'échelon régional, pour coordonner le développement des règles de gestion de la congestion.

I.2. *Règlement (CE) n° 714/2009 du Parlement européen et du Conseil du 13 juillet 2009 sur les conditions d'accès au réseau pour les échanges transfrontaliers d'électricité et abrogeant le Règlement (CE) n° 1228/2003*

2. La CREG rappelle qu'aux termes de l'article 249 du traité instituant la Communauté européenne, le règlement n° 714/2009 a une portée générale, est obligatoire dans tous ses éléments et est directement applicable dans tout Etat membre.

3. L'article 16.1 du Règlement n° 714/2009 précise que les problèmes de congestion sur le réseau sont traités par des solutions non discriminatoires, basées sur le marché et qui donnent des signaux économiques efficaces aux opérateurs du marché et aux gestionnaires de réseaux de transport concernés.

4. L'article 16.2 du Règlement n° 714/2009 stipule que les procédures de restriction des transactions ne peuvent être appliquées que dans des situations d'urgence où le gestionnaire de réseau de transport doit agir rapidement et où le rappel ou les échanges de contrepartie ne sont pas possibles, et que sauf cas de force majeure, les opérateurs du marché auxquels a été attribuée une capacité sont indemnisés pour toute restriction.

5. L'article 16.3 du Règlement n° 714/2009 prévoit que la capacité maximale des interconnexions et/ou des réseaux de transport ayant une incidence sur les flux transfrontaliers est mise à la disposition des opérateurs du marché, conformément aux normes de sécurité de l'exploitation sûre du réseau.

6. L'article 16.4 du Règlement n° 714/2009 concerne l'horaire des nominations et la

réattribution des capacités non utilisées. Il prévoit que les opérateurs du marché préviennent les gestionnaires de réseaux de transport concernés, suffisamment longtemps avant le début de la période d'activité visée, de leur intention d'utiliser ou non la capacité attribuée. Toute capacité attribuée non utilisée est réattribuée au marché selon une procédure ouverte, transparente et non discriminatoire.

7. L'article 16.5 du règlement n° 714/2009 prévoit que dans la mesure où c'est techniquement possible, les gestionnaires de réseaux de transport compensent les demandes de capacité de tout flux d'énergie dans la direction opposée sur la liaison encombrée afin d'utiliser cette liaison à sa capacité maximale.

I.3. Les « Orientations pour la gestion et l'attribution de la capacité de transfert disponible des interconnexions entre réseaux nationaux »

8. L'annexe I du règlement n° 714/2009 comporte des orientations pour la gestion de la congestion et l'attribution de la capacité de transfert disponible sur les interconnexions (liaisons) entre réseaux nationaux (ci-après : orientations). Les dispositions de ces orientations qui sont pertinentes pour la présente décision sont fournies ci-après.

1. GENERALITES

[...]

1.9. Au plus tard le 1er janvier 2008, des mécanismes de gestion intrajournalière de la congestion des capacités d'interconnexion sont établis d'une manière coordonnée et dans des conditions de fonctionnement sûres, de manière à maximaliser les possibilités d'échanges et à assurer l'équilibrage transfrontalier.

1.10. Les autorités de régulation nationales évaluent régulièrement les méthodes de gestion de la congestion, en veillant notamment au respect des principes et des règles établis dans le présent règlement et les présentes orientations, ainsi que des modalités et conditions fixées par les autorités de régulation elles-mêmes en vertu de ces principes et de ces règles. Cette évaluation comprend une consultation de tous les acteurs du marché ainsi que des études spécialisées.

2. METHODES DE GESTION DE LA CONGESTION

2.1. Les méthodes de gestion de la congestion sont fondées sur les mécanismes du marché, de manière à favoriser un commerce transfrontalier efficace. À cet effet, les capacités sont attribuées uniquement sous la forme de ventes aux enchères explicites (capacités) ou implicites (capacités et énergie). Les deux méthodes peuvent coexister pour la même interconnexion. Pour les échanges intrajournaliers, un régime de continuité peut être appliqué.

2.2. Selon la situation de concurrence, les mécanismes de gestion de la congestion doivent pourvoir à l'attribution des capacités de transport tant à long qu'à court terme.

2.3. Chaque procédure d'attribution de capacités attribue une fraction prescrite de la capacité d'interconnexion disponible, plus toute capacité restante qui n'a pas été attribuée précédemment et toute capacité libérée par les détenteurs de capacités ayant bénéficié d'attributions antérieures.

[...]

2.5. Les droits d'accès pour les attributions à long et à moyen terme sont des droits d'utilisation de capacités de transport fermes. Ils sont soumis aux principes de l'obligation d'utiliser les droits sous peine de perte définitive ("use-it-or-lose-it") ou de vente ("use-it-or-sell-it") au moment de la réservation.

2.6. Les GRT définissent une structure appropriée pour l'attribution des capacités selon les échéances. Cette structure peut comprendre une option permettant de réserver un pourcentage minimal de capacité d'interconnexion pour une attribution journalière ou intrajournalière. Cette structure d'attribution est soumise à l'appréciation des autorités de régulation concernées. Pour élaborer leurs propositions, les GRT tiennent compte :

a) des caractéristiques des marchés;

b) des conditions opérationnelles, telles que les conséquences d'une comptabilisation nette des opérations fermement programmées;

c) du degré d'harmonisation des pourcentages et des délais adoptés pour les différents mécanismes d'attribution de capacités en vigueur.

[...]

2.10. En principe, tous les opérateurs potentiels du marché sont autorisés à participer sans restriction au processus d'attribution. Pour éviter l'apparition ou l'aggravation de problèmes liés à l'utilisation éventuelle d'une position dominante par un acteur quelconque du marché, les autorités compétentes en matière de régulation et/ou de concurrence, selon le cas, peuvent imposer des restrictions en général ou à une société en particulier en raison d'une position dominante sur le marché.

2.11. Les opérateurs du marché communiquent aux GRT leurs demandes fermes de réservation de capacités avant une date définie pour chaque échéance. La date est fixée de manière à permettre aux GRT de réaffecter les capacités inutilisées dans l'optique d'une nouvelle attribution lors de l'échéance suivante, y compris les sessions intrajournalières.

2.12. Les capacités peuvent faire l'objet d'échanges sur le marché secondaire, à condition que le GRT soit informé suffisamment à l'avance. Lorsqu'un GRT refuse un échange (transaction) secondaire, il doit notifier et expliquer clairement et d'une manière transparente ce refus à tous les opérateurs du marché et en informer l'autorité de régulation.

2.13. Les conséquences financières d'un manquement aux obligations liées à l'attribution de capacités sont à la charge des responsables de la défaillance. Lorsque les opérateurs du marché n'utilisent pas les capacités qu'ils se sont engagés à utiliser ou, dans le cas de capacités ayant fait l'objet d'une vente aux enchères explicite, ne procèdent pas à des échanges sur le marché secondaire ou ne restituent pas les capacités en temps voulu, ils perdent leurs droits d'utilisation de ces capacités et sont redevables d'un défraiement reflétant les coûts. Ce défraiement éventuel en cas de non-utilisation de capacités doit être justifié et proportionné. De même, si un GRT ne respecte pas son obligation, il est tenu d'indemniser l'opérateur du marché pour la perte des droits d'utilisation de capacités. Aucun préjudice indirect n'est pris en compte à cet effet. Les concepts et les méthodes de base permettant de déterminer les responsabilités en cas de manquement à des obligations sont définis au préalable en ce qui concerne les conséquences financières et sont soumis à l'appréciation de la ou des autorités de régulation nationales compétentes.

[...]

3. COORDINATION

[...]

4. CALENDRIER DES OPERATIONS SUR LE MARCHE

[...]

4.2. La sécurité du réseau étant pleinement prise en considération, la réservation des droits de transport s’effectue suffisamment à l'avance, avant les sessions à un jour sur tous les marchés organisés concernés et avant la publication des capacités à attribuer au titre du mécanisme d'attribution à un jour ou intrajournalière. Les demandes de réservation de droits de transport dans la direction opposée sont comptabilisées sur une base nette de manière à assurer une utilisation efficace de l'interconnexion.

[...]

5. TRANSPARENCE

5.1. Les GRT publient toutes les données utiles se rapportant à la disponibilité, à l'accessibilité et à l'utilisation du réseau, comprenant un rapport sur les lieux et les causes de congestion, les méthodes appliquées pour gérer la congestion et les projets concernant sa gestion future.

[...]

5.3. Les GRT décrivent en détail et mettent d'une manière transparente à la disposition de tous les utilisateurs potentiels du réseau les procédures en usage en matière de gestion de la congestion et d’attribution des capacités, ainsi que les délais et les procédures de demande de capacités, une description des produits proposés et des droits et obligations des GRT et de l’opérateur qui obtient la capacité, y compris les responsabilités en cas de manquement aux obligations.

[...]

5.5. Les GRT publient toutes les données utiles concernant les échanges transfrontaliers sur la base des meilleures prévisions possibles. Pour assurer le respect de cette obligation, les opérateurs du marché concernés communiquent aux GRT toutes les données utiles. La façon dont ces informations sont publiées est soumise à l'appréciation des autorités de régulation. Les GRT publient au moins :

a) chaque année : des informations sur l'évolution à long terme de l'infrastructure de transport et son incidence sur la capacité de transport transfrontalier;

b) chaque mois : les prévisions à un mois et à un an des capacités de transport à la disposition du marché, en tenant compte de toutes les informations utiles dont le GRT dispose au moment du calcul des prévisions (par exemple, l'effet des saisons sur la capacité des lignes, les activités d'entretien sur le réseau, la disponibilité des unités de production, etc.);

c) chaque semaine : les prévisions à une semaine des capacités de transport à la disposition du marché, en tenant compte de toutes les informations utiles dont le GRT dispose au moment du calcul des prévisions, telles que les prévisions météorologiques, la planification des travaux d'entretien du réseau, la disponibilité des unités de production, etc.;

d) chaque jour : les capacités de transport à un jour et intrajournalières à la disposition du marché pour chaque unité de temps du marché, en tenant compte de l'ensemble des réservations à un jour sur une base nette, des programmes de production à un jour, des prévisions concernant la demande et de la planification des travaux d'entretien du réseau;

e) la capacité totale déjà attribuée, par unité de temps du marché, et toutes les conditions utiles dans lesquelles cette capacité peut être utilisée (par exemple, le prix d'équilibre des ventes aux enchères, les obligations concernant les modalités d'utilisation des capacités, etc.), afin de déterminer les éventuelles capacités restantes;

f) les capacités attribuées, le plus tôt possible après chaque attribution, ainsi qu'une indication des prix payés;

g) la capacité totale utilisée, par unité de temps du marché, immédiatement après la réservation;

h) quasiment en temps réel : les flux commerciaux et physiques réalisés, sur une base agrégée, par unité de temps du marché, comprenant une description des effets des mesures correctives éventuelles prises par les GRT (par exemple, la restriction des transactions) pour résoudre les problèmes de réseau ou de système;

i) les informations ex-ante relatives aux indisponibilités prévues et les informations ex-post pour le jour précédent relatives aux indisponibilités prévues et imprévues des unités de production d'une capacité supérieure à 100 MW.

5.6. Toutes les informations utiles doivent être mises à la disposition du marché en temps voulu pour permettre la négociation de toutes les transactions (notamment la date de *négociation des contrats de fourniture annuels pour les clients industriels ou la date à laquelle les offres doivent être lancées sur les marchés organisés).*

5.7. Le GRT publie les informations utiles sur la demande prévisionnelle et sur la production en fonction des échéances visées aux points 5.5 et 5.6. Le GRT publie également les informations utiles et nécessaires pour le marché de l'équilibrage transfrontalier.

5.8. Lorsque des prévisions sont publiées, les valeurs réalisées ex-post pour les données de prévision sont également publiées dans l'intervalle de temps suivant celui auquel la prévision s'applique ou au plus tard le jour suivant (J+1).

5.9. Toutes les informations publiées par les GRT sont mises à disposition librement sous une forme facilement accessible. Toutes les données sont également accessibles sur des supports appropriés et normalisés servant à l'échange d'informations, à définir en étroite collaboration avec les acteurs du marché. Les données comprennent des informations sur les périodes antérieures, avec un minimum de deux ans, afin que les nouveaux opérateurs du marché puissent également en prendre connaissance.

[...]

I.4. La loi électricité

9. L'article 2, 7° de la loi du 29 avril 1999 relative à l'organisation du marché de l'électricité (ci-après : la loi électricité) définit le terme « réseau de transport » comme le réseau national de transport d'électricité, qui comprend les lignes aériennes, câbles souterrains et installations servant à la transmission d'électricité de pays à pays et à destination de clients directs des producteurs et de distributeurs établis en Belgique, ainsi qu'à l'interconnexion entre centrales électriques et entre réseaux électriques.

10. L'article 15, § 1er de la même loi prévoit que les clients éligibles ont un droit d'accès au réseau de transport aux tarifs fixés conformément à l'article 12, et que le gestionnaire du réseau ne peut refuser l'accès au réseau que s'il ne dispose pas de la capacité nécessaire ou si le demandeur ne satisfait pas aux prescriptions techniques prévues dans le règlement technique.

11. L'article 23, §2, 9° de la loi prévoit que la CREG contrôle l'application du règlement technique et approuve les documents visés par ce règlement, à savoir ceux qui concernent les conditions de raccordement et l'accès au réseau de transport.

I.5. Le règlement technique

12. L’article 180, §1er du règlement technique prévoit que le gestionnaire du réseau détermine de manière non discriminatoire et transparente les méthodes de gestion de la congestion qu'il applique.

L’article 180, §2, précise que les méthodes de gestion de la congestion, ainsi que les règles de sécurité, sont notifiées à la CREG pour approbation et publiées conformément à l’article 26 du présent règlement.

Conformément à l’article 180, §3, du règlement technique, le gestionnaire du réseau doit notamment veiller, dans l'élaboration et la mise en œuvre de ces méthodes de gestion de la congestion :

1° à prendre en compte, autant que possible, la direction des flux d'électricité, en particulier lorsque les transactions diminuent effectivement la congestion ;

2° à éviter, autant que possible, les effets significatifs sur les flux d’énergie dans d’autres réseaux ;

3° à résoudre les problèmes de congestion du réseau de préférence sans recourir à une sélection entre les transactions des différents responsables d'accès ;

4° à fournir des signaux économiques appropriés aux utilisateurs du réseau concernés.

Ces méthodes de gestion de la congestion doivent notamment être basées, conformément à l’article 180, §4, du règlement technique sur :

1° les enchères de la capacité disponible ;

2° la coordination de l'appel des unités de production raccordées dans la zone de réglage et/ou, moyennant l'accord du(des) gestionnaire(s) d'un réseau étranger, par l'appel coordonné des unités de production raccordées dans la(les) zone(s) de réglage étrangère(s) concernée(s).

En vertu de l’article 181, §1er, du règlement technique, les méthodes de gestion de la congestion prévues à l'article 180 ont notamment pour objectif de :

1° offrir toute la capacité disponible au marché selon des méthodes transparentes et non discriminatoires, en organisant, le cas échéant, une vente aux enchères dans laquelle les capacités peuvent être vendues pour une durée différente et avec différentes caractéristiques (par exemple, en ce qui concerne la fiabilité attendue de la capacité disponible en question) ;

2° offrir la capacité disponible dans une série de ventes qui peuvent être tenues sur une base temporelle différente ;

3° offrir à chacune des ventes une fraction déterminée de la capacité disponible, plus toute capacité restante qui n’a pas été attribuée lors des ventes précédentes ;

4° permettre la commercialisation de la capacité offerte.

L’article 181, §2, prévoit que les méthodes de gestion de la congestion peuvent faire appel, dans des situations d'urgence, à l'interruption des échanges transfrontaliers suivant des règles de priorité préétablies qui sont notifiées à la CREG et publiées conformément à l'article 26 du présent arrêté.

Son paragraphe 3 précise que le gestionnaire du réseau doit se concerter avec les gestionnaires de réseaux voisins pour ce qui concerne les méthodes de gestion des congestions.

13. Selon l’article 183, §1er, du règlement technique, le gestionnaire du réseau veille à l’exécution d’une ou plusieurs méthodes d’allocation aux responsables de l’accès de la capacité disponible pour les échanges d’énergie avec les réseaux étrangers.

Selon l’article 183, §2, du règlement technique, ces méthodes doivent être transparentes et non discriminatoires. Elles sont portées à la connaissance de la CREG pour approbation, et publiées conformément à l'article 26 du règlement technique.

Enfin, l’article 183, §3, du règlement technique ajoute que ces méthodes visent à optimaliser l'utilisation de la capacité du réseau conformément à son article 179.

14. Conformément à l’article 184 du règlement technique, ces méthodes d'allocation de la capacité visent notamment :

1° à minimaliser, dans toute la mesure du possible, lors de la gestion d'une congestion, toute différence de traitement entre les divers types de transactions transfrontalières, qu'il s'agisse de contrats bilatéraux physiques ou d'offres sur des marchés organisés étrangers ;

2° à mettre toute capacité inutilisée à la disposition d'autres acteurs du marché ;

3° à déterminer les conditions précises de fermeté pour la capacité mise à disposition des acteurs du marché.

II. ANTECEDENTS

15. Le 1er décembre 2005, la CREG adopte la décision (B)051201-CDC-494 relative à la demande d'approbation de la proposition de la SA Elia System Operator concernant les méthodes pour la gestion des congestions et les méthodes pour l'octroi, aux responsables d'accès, de la capacité disponible sur la liaison France-Belgique (ci-après : la décision du 1er décembre 2005). Par sa décision, la CREG accepte la proposition d'Elia d'allouer 1300 MW sur une base annuelle et un minimum de 400 MW sur une base mensuelle. L'idée est que la capacité mensuelle disponible soit maximisée, avec une valeur minimale de 400 MW.

16. Par courrier du 28 novembre 2006, Elia informe la CREG du fait que lors de la réunion "Users' Group Elia" du 23 novembre 2006, une résolution a été discutée en faveur d'un rééquilibrage entre les capacités annuelles, mensuelles et journalières allouées à la frontière franco-belge (sens France-Belgique) pour l'année 2007, et qu'un certain nombre de membres présents ont marqué leur accord sur une nouvelle répartition qui vise à diminuer la capacité allouée sur base annuelle et à augmenter les capacités à mettre à la disposition du couplage des marchés. Une telle mesure aurait un effet favorable sur les prix du marché belge. Dans sa lettre, Elia dit espérer que la CREG ne s'opposera pas à la mise en œuvre de cette résolution.

17. Le 7 décembre 2006, la CREG adopte la décision (B) 061207-CDC-610 relative à la demande d'approbation de la proposition de la S.A. Elia System Operator relative aux méthodes de gestion de la congestion et aux méthodes pour l'allocation aux responsables d'accès de la capacité disponible sur l'interconnexion France-Belgique (ci-après : la décision du 7 décembre 2006). Par cette décision, prise en application des articles 180, §2, et 183, §2, du règlement technique, la CREG refuse notamment d'approuver la proposition d'Elia relative au réaménagement des capacités entre les différents horizons de temps. La CREG motive son refus par l'impossibilité d'évaluer valablement la mesure proposée par Elia sur la seule base de l'analyse fournie par Elia et compte tenu du délai extrêmement court dont elle dispose. La CREG renvoie également à l'absence d'une consultation ouverte et transparente de l'ensemble des acteurs du marché et le manque de prévisibilité de la mesure pour tous les acteurs du marché. La CREG y indique cependant rester ouverte à l'idée d'un réaménagement de la capacité disponible sur les différents horizons de temps qui serait dans l'intérêt du marché.

18. Après avoir constaté en consultant le site Internet d'Elia, que les capacités mensuelles annoncées pour les mois de janvier et de février 2007 étaient de 400 MW à la frontière France-Belgique (sens France-Belgique), alors que les capacités allouées pour les mêmes mois en 2006 étaient de 1450 MW, la CREG adresse, le 18 décembre 2006, un courrier à Elia dans lequel elle demande à Elia de lui exposer les raisons précises de cette importante diminution

19. Par un courrier du 22 décembre 2006, Elia répond ne pas comprendre l'étonnement de la CREG vu les arguments déjà invoqués par Elia en faveur d'une rectification de la répartition des capacités dans ses courriers du 28 novembre et du 4 décembre 2006. Elia y explique qu'elle a décidé conjointement avec RTE (le gestionnaire du réseau de transport français), de fixer à la valeur de 400 MW la capacité mensuelle pour les mois de janvier et février 2007, dans le respect de la décision de la CREG du 7 décembre 2006.

20. Par courrier du 27 décembre 2006, Elia informe la CREG de son intention d'organiser une concertation de l'ensemble des acteurs du marché au sujet du réaménagement de la répartition de la capacité disponible sur les différents horizons de temps.

21. Par courrier du 8 février 2007, la CREG précise à Elia qu'elle constate que celle-ci a pris cette mesure unilatéralement, et donc sans la soumettre préalablement à l'approbation de la CREG, alors qu'une telle mesure implique une modification des méthodes de gestion de la congestion alors appliquées. La CREG constate dans ce courrier que, par cette mesure unilatérale, Elia contourne le refus de la CREG dans sa décision du 7 décembre 2006, d'approuver la proposition d'Elia formulée dans son courrier du 4 décembre 2006. Dans l'attente de l'introduction d'un dossier complet auprès de la CREG, et de l'organisation par Elia d'une consultation complète du marché, la CREG demande par ce courrier à Elia de revenir au principe selon lequel la capacité mensuelle est égale à la capacité maximale pouvant être garantie sur base mensuelle, et de ne pas la limiter artificiellement à 400 MW.

22. Par un courrier du 14 février 2007, Elia répond s'étonner de la réaction de la CREG et prétend que c'est erronément que la CREG conclut qu'Elia aurait contourné le refus de la CREG dans sa décision du 7 décembre 2006. Elia indique en outre que la mesure prise est en conformité avec la décision de la CREG du 1er décembre 2005 puisque le seuil des 400 MW de capacité mensuelle est respecté, et réitère ensuite des arguments déjà invoqués dans ses courriers des 28 novembre et 4 décembre 2006.

23. Le 2 mars 2007, la CREG reçoit d'Elia un courrier daté du 27 février 2007 comprenant des documents qui seront utilisés lors de la réunion de consultation des acteurs du marché du 6 mars 2007 dont il est question au § 23.

24. Le 6 mars 2007, Elia organise conjointement avec RTE, une réunion de consultation de acteurs du marché au sujet du réaménagement de la capacité disponible sur les différents horizons de temps, portant sur les mois restants de l'année 2007 d'une part, et sur l'année 2008 d'autre part. Elia et RTE publient peu après le compte rendu de cette réunion sur leur site Internet respectif.

25. Par courrier du 16 mars 2007, Elia soumet à l'approbation de la CREG sa proposition relative aux méthodes de gestion de la congestion sur l'interconnexion France-Belgique, visant à réaménager la capacité disponible entre les différents horizons de temps, pour application lors de la détermination des capacités mensuelles à allouer pour les mois de mai à décembre 2007. En ce qui concerne l'année 2008, Elia s'engage à organiser avec RTE une consultation à ce sujet dans le courant de l'automne 2007.

26. Le 12 avril 2007, la CREG adopte la décision (B)070412-CDC-677 relative à la demande d'approbation de la proposition de la S.A. Elia System Operator relative aux méthodes de gestion de la congestion sur l'interconnexion France-Belgique (ci-après : la décision du 12 avril 2007). Par sa décision, la CREG refuse d'approuver en l'état la proposition d'Elia relative aux méthodes de gestion de la congestion sur l'interconnexion Belgique-France, visant à réaménager la répartition de la capacité entre les différents horizons de temps. Néanmoins, vu l'absence d'impact très négatif sur le marché, la CREG autorise Elia à mettre en œuvre le réaménagement proposé des capacités mensuelles et journalières jusqu'à la fin du mois de décembre 2007. La CREG demande également, dans cette décision, qu'Elia améliore la transparence de la gestion de l'interconnexion et qu'elle soumette, pour le 15 octobre 2007 au plus tard, une nouvelle proposition pour la répartition des capacités pour l'année 2008 qui comprenne une justification fouillée de la répartition proposée, dont l'impact du marché secondaire et qui indique clairement le niveau de capacité qui sera garanti tout au long de l'année 2008, compte tenu des renforcements effectués sur l'interconnexion.

27. Le 1er octobre 2007, Elia et RTE organisent à Paris une consultation des acteurs du marché relative à de nouvelles propositions faites par les gestionnaires de réseau pour le réaménagement des capacités sur les différents horizons de temps. Cette réunion permet de

dégager une clé de répartition acceptable par l'ensemble des participants.

28. Le 24 octobre 2007, Elia communique à la CREG, conformément à l'article 2.6 des nouvelles orientations, sa proposition, établie conjointement avec RTE, pour le réaménagement des capacités pour l'année 2008.

29. Au cours du mois de novembre 2007, le régulateur français CRE (Commission de Régulation de l'Energie) et la CREG se sont concertés au sujet de la proposition des gestionnaires de réseau relative à la répartition des capacités sur les différents horizons de temps.

30. Le 20 novembre 2007, la CREG reçoit d'Elia une lettre précisant que sa proposition du 24 octobre 2007 a été soumise notamment dans le cadre des articles 180, §2, et 183, §3, de l'arrêté royal du 19 décembre 2002 établissant un règlement technique pour la gestion du réseau de transport et l'accès à celui-ci.

31. Le 22 novembre 2007, la CREG adopte la décision (B)071122-CDC-729 relative à la demande d'approbation de la proposition de la S.A. Elia System Operator relative aux méthodes de gestion de la congestion sur l'interconnexion France-Belgique (ci-après : la décision du 22 novembre 2007). Par sa décision, la CREG refuse d'approuver la proposition d'Elia relative aux méthodes de gestion de la congestion sur l'interconnexion Belgique-France, visant à réaménager la répartition de la capacité entre les différents horizons de temps. Néanmoins, vu l'absence d'impact très négatif sur le marché, la CREG autorise Elia à mettre en œuvre le réaménagement proposé des capacités mensuelles et journalières jusqu'à la fin du mois de décembre 2008. La CREG demande également, dans cette décision, qu'Elia soumette, pour le 15 octobre 2008 au plus tard, une nouvelle proposition pour la répartition des capacités pour l'année 2009, qui comprenne une justification de la répartition proposée, dont l'impact du marché secondaire et qui indique clairement le niveau de capacité qui sera garanti tout au long de l'année 2009.

32. Le 7 novembre 2008, la CREG reçoit la proposition d'Elia, établie conjointement avec RTE, relative aux règles de répartition entre les différents horizons de temps de la capacité qui sera allouée en 2009 sur l'interconnexion France-Belgique. Cette proposition est soumise par Elia dans le cadre de l'article 2.6 de l'annexe du règlement (CE) n° 1228/2003 et dans le cadre des articles 180, §2, et 183, §3, de l'arrêté royal du 19 décembre 2002 établissant un

règlement technique pour la gestion du réseau de transport et l'accès à celui-ci.

33. Par sa lettre du 5 décembre 2008, la CREG a invité ELIA à s'expliquer relativement au volume des capacités garanties sur l'interconnexion France-Belgique et en particulier sur l'impact des transformateurs-déphaseurs récemment installés. Lors de la réunion du 9 décembre 2008, Elia a expliqué les méthodes de calcul des capacités et l'impact des flux de bouclage sur celles-ci. La CREG a exprimé sa préoccupation concernant le rendement des investissements réalisés par Elia dans les interconnexions, compte tenu des promesses répétées faites par Elia dans le passé. Elia a expliqué les différences sur base de l'évolution récente des flux physiques dans la région et leur impact sur les congestions. Elia s'est engagée à fournir pour janvier 2009 une justification détaillée de leurs calculs ex-ante et des résultats et avantages réellement observés pour le marché belge.

34. Le 11 décembre 2008, la CREG adopte la décision (B) 081211-CDC-801 relative à la demande d'approbation de la proposition de la S.A. Elia System Operator concernant les méthodes pour la gestion des congestions et les méthodes pour l'octroi, aux responsables d'accès, de la capacité disponible sur la liaison Belgique-France (ci-après : la décision du 11 décembre 2008). Par sa décision, la CREG refuse d'approuver la proposition d'Elia relative aux méthodes de gestion de la congestion sur l'interconnexion Belgique-France, visant à réaménager la répartition de la capacité entre les différents horizons de temps. Néanmoins, vu l'absence d'impact très négatif sur le marché, la CREG autorise Elia à mettre en œuvre le réaménagement proposé des capacités mensuelles et journalières jusqu'à la fin du mois de décembre 2009. La CREG demande également, dans cette décision, qu'Elia soumette, pour le 15 octobre 2009 au plus tard, une nouvelle proposition pour la répartition des capacités pour l'année 2010. La CREG demande à Elia, pour le mois de janvier 2009, de justifier le bien fondé des investissements relativement aux capacités d'interconnexion réalisés dans le passé ainsi qu'une justification détaillée des investissements en cours et de relever à 2000 MW la capacité minimale dès la mise en service commerciale des transformateurs-déphaseurs. La CREG demande qu'Elia publie, en novembre 2009, l'engagement des gestionnaires de réseau (RTE et ELIA) concernant le niveau minimal de la capacité qu'ils alloueront tout au long de l'année en 2010.

35. Le 13 novembre 2009, la CREG reçoit la proposition d'Elia, établie conjointement avec RTE, relative aux règles de répartition entre les différents horizons de temps de la capacité qui sera allouée en 2010 sur l'interconnexion France-Belgique. Cette proposition est soumise par Elia dans le cadre de l'article 2.6 de l'annexe du règlement (CE) n° 1228/2003

et dans le cadre des articles 180, §2, et 183, §3, de l'arrêté royal du 19 décembre 2002 établissant un règlement technique pour la gestion du réseau de transport et l'accès à celui-ci.

36. Par courrier du 13 novembre 2009, Elia soumet pour approbation à la CREG le modèle pour le calcul des capacités totales de transfert et de la marge de fiabilité de transport pour les capacités annuelles et mensuelles ("Model voor de berekening van de totale overdrachtcapaciteit en de transportbetrouwbaarheidsmarge voor jaar- en maandcapaciteiten").

37. Le 26 novembre 2009, la CREG adopte la décision (B) 091126-CDC-926 relative à la demande d'approbation de la proposition de la S.A. Elia System Operator relative aux méthodes de gestion de la congestion et aux méthodes pour l'allocation aux responsables d'accès de la capacité disponible sur l'interconnexion Belgique-France (ci-après : la décision du 26 novembre 2009). Par sa décision, la CREG refuse d'approuver la proposition d'Elia relative aux méthodes de gestion de la congestion sur l'interconnexion Belgique-France, visant à réaménager la répartition de la capacité entre les différents horizons de temps. Néanmoins, vu l'absence d'impact très négatif sur le marché, la CREG autorise Elia à mettre en œuvre le réaménagement proposé des capacités mensuelles et journalières jusqu'à la fin du mois de décembre 2010. La CREG demande également, dans cette décision, qu'Elia soumette, pour le 15 octobre 2010 au plus tard, une nouvelle proposition pour la répartition des capacités pour l'année 2011. La CREG demande qu'Elia publie, en novembre 2010, l'engagement des gestionnaires de réseau (RTE et ELIA) concernant le niveau minimal de la capacité qu'ils alloueront tout au long de l'année en 2011.

38. Le 4 novembre 2010, la CREG reçoit la proposition d'Elia, établie conjointement avec RTE, relative aux règles de répartition entre les différents horizons de temps de la capacité qui sera allouée en 2011 sur l'interconnexion France-Belgique. Cette proposition est soumise par Elia dans le cadre de l'article 2.6 de l'annexe du règlement (CE) n° 1228/2003 et dans le cadre des articles 180, §2, et 183, §3, de l'arrêté royal du 19 décembre 2002 établissant un règlement technique pour la gestion du réseau de transport et l'accès à celui-ci.

39. Le 7 octobre 2010, la CREG adopte la décision (B)101007-CDC-993 relative à la "demande d'approbation de la proposition de la SA Elia System Operator modifiant les méthodes pour la gestion des congestions et les méthodes pour l'octroi, aux responsables d'accès, de la capacité disponible pour les échanges d'énergie avec le réseau français et

néerlandais, comme fixé dans le cadre de l'initiative régionale Europe centre-ouest".

40. Le 28 octobre 2010, la CREG adopte la décision (B)101028-CDC-998 relative à la "demande d'approbation de la proposition de la SA Elia System Operator concernant les méthodes pour la gestion des congestions et les méthodes pour l'octroi, aux responsables d'accès, de la capacité disponible sur les interconnexions Belgique-France et Belgique-Pays-Bas via des enchères implicites, organisées dans le cadre du couplage du marché de la région du Europe centre-ouest".

41. Le 25 novembre 2010, la CREG adopte la décision (B) 101125-CDC-1018 relative à la demande d'approbation de la proposition de la S.A. Elia System Operator concernant les méthodes pour la gestion des congestions et les méthodes pour l'octroi, aux responsables d'accès, de la capacité disponible sur la liaison Belgique-France (ci-après : la décision du 25 novembre 2010). Par sa décision, la CREG refuse d'approuver la proposition d'Elia relative aux méthodes de gestion de la congestion sur l'interconnexion Belgique-France, visant à réaménager la répartition de la capacité entre les différents horizons de temps. Néanmoins, vu l'absence d'impact très négatif sur le marché, la CREG autorise Elia à mettre en œuvre le réaménagement proposé des capacités mensuelles et journalières jusqu'à la fin du mois de décembre 2010. La CREG demande également, dans cette décision, qu'Elia soumette, pour le 15 octobre 2011 au plus tard, une nouvelle proposition pour la répartition des capacités pour l'année 2012. La CREG demande qu'Elia publie, en novembre 2011, l'engagement des gestionnaires de réseau (RTE et ELIA) concernant le niveau minimal de la capacité qu'ils alloueront tout au long de l'année en 2012.

42. Le 29 juin 2011, Elia organise, conjointement avec RTE, une consultation de marché "on the Split Rules on the French-Belgian Border".

43. Le 15 septembre 2011, la CREG a adopté la décision (B)110915-CDC-1097 relative à la demande d'approbation de la proposition de la SA Elia System Operator relative au modèle général de calcul de la capacité de transfert pour l'année et le mois et de la marge de fiabilité du transport et aux méthodes de gestion de la congestion pour les échanges énergétiques avec les réseaux français et néerlandais, telles qu'établies dans le cadre de la région Europe centre-ouest.

44. Le 14 octobre 2011, la CREG reçoit la proposition d'Elia, établie conjointement avec

RTE, relative aux règles de répartition entre les différents horizons de temps de la capacité qui sera allouée en 2012 sur l'interconnexion France-Belgique. Cette proposition est introduite pat Elia dans le cadre de l'article 2.6 de l'annexe du Règlement (CE) n° 714/2009.

45. Le 10 novembre 2011, la CREG adopte la décision (B)111110-CDC-1123 relative à la 'demande d'approbation de la proposition de la S.A. Elia System Operator relative aux méthodes de gestion de la congestion et aux méthodes pour l'allocation aux responsables d'accès de la capacité disponible sur l'interconnexion Belgique France' (ci-après : la décision du 10 novembre 2011). Par sa décision, la CREG approuve la proposition d'Elia relative aux méthodes de gestion de la congestion sur l'interconnexion Belgique-France, en vue de la répartition de la capacité entre les différents horizons de temps. La CREG demande également, dans cette décision, qu'Elia soumette, pour le 15 octobre 2012 au plus tard, une nouvelle proposition pour la répartition des capacités pour l'année 2013. La CREG demande qu'Elia publie, en novembre 2012, l'engagement des gestionnaires de réseau (RTE et ELIA) concernant le niveau minimal de la capacité qu'ils alloueront tout au long de l'année en 2013.

46. Le 2 octobre 2012, la CREG reçoit la proposition d'Elia, établie conjointement avec RTE, relative aux règles de répartition entre les différents horizons de temps de la capacité qui sera appliquée à partir de 2013 sur l'interconnexion France-Belgique. Cette proposition est introduite pat Elia dans le cadre de l'article 2.6 de l'annexe du Règlement (CE) n° 714/2009.

47. Le 26 octobre 2012, la CREG envoie son "projet de décision 1200 relative à la méthode de répartition des capacités entre les différents horizons de temps sur la liaison entre la Belgique et la France pour 2013" à Elia. La CREG a ainsi prévu la possibilité pour Elia de transmettre des remarques sur le projet de décision.

48. Dans sa lettre du 5 novembre 2012, reçue le 6 novembre 2012, Elia a formulé ses remarques sur le projet de décision précité. Elia y fait remarquer que sa proposition ne se limite pas à 2013, mais porte sur 2013 et les années suivantes. Elia demande une adaptation des paragraphes pertinents. De plus, Elia indique quels passages de l'annexe de la décision comportent des données confidentielles.

III. ANALYSE DES MÉTHODES DE GESTION DE LA CONGESTION SUR L'INTERCONNEXION BELGIQUE-FRANCE PROPOSÉES PAR ELIA

III.1. Remarques préliminaires

49. Le présent titre analyse la conformité de la proposition d'Elia au regard du cadre légal exposé au titre I de la présente décision.

50. La CREG examine en particulier si la proposition d'Elia tient compte des remarques formulées par la CREG dans sa décision du 10 novembre 2011.

51. La présente décision ne porte aucunement préjudice aux décisions de la CREG du 7 décembre 2006, du 22 novembre 2007, du 11 décembre 2008, du 26 novembre 2010 et du 10 novembre 2011. Les remarques qui y sont formulées restent entièrement valables.

52. La présente décision vaut sans préjudice de toute adaptation ultérieure des méthodes de gestion de la congestion qui pourrait être exigée dans le cadre des nouvelles orientations.

53. La proposition d'Elia de répartition des capacités disponibles entre les différents horizons de temps porte sur la méthode de répartition des capacités entre les différentes échéances sur la liaison entre la Belgique et la France à partir de l'année 2013. La CREG prévoit qu'Elia soumette à la CREG une proposition d'approbation pour chaque adaptation apportée à cette méthode.

54. La présente décision concerne uniquement la question de la répartition de la capacité sur les différents horizons de temps et ne concerne pas la méthode de calcul des capacités mensuelles et annuelles.

55. La CREG souhaite rappeler qu'elle considère que les valeurs NTC minimales sont de 600 MW dans le sens Belgique-France et de 1700 MW dans le sens France-Belgique.

56. La présente décision concerne uniquement la question de la répartition de la capacité

sur les différents horizons de temps pour l'interconnexion Belgique - France et ne concerne pas l'interconnexion Belgique – Pays-Bas.

57. La CREG tient compte des remarques qu'Elia lui a transmises suite au projet de décision 1200. La CREG note que la proposition porte sur 2013 et les années suivantes.

III.2. Analyse

58. La proposition d'Elia pour les règles relatives à la méthode de répartition des capacités à partir de l'année 2013 est synthétisée ci-après.
La valeur de la Capacité de transfert nette annuelle ou "Net Transfer Capacity" (NTCy) pour 2013 ne sera disponible qu'au début du mois de novembre 2012 selon Elia. La valeur de cette NTCy constitue la base de la détermination des capacités pour les différentes échéances, qui sont désignées par l'ATC ("Available Transfer Capacity"). L'ATC annuelle est déterminée comme suit :
ATCy = NTCy – MAmin – DAmin,
où MAmin et DAmin sont les capacités mensuelles et journalières réservées annuellement et s'élèvent à 200 MW.
La capacité complémentaire déterminée mensuellement, en plus de la capacité garantie de façon minimale sur base annuelle, est répartie sur la capacité mensuelle et journalière. Pour le sens France-Belgique, 25 % de cette capacité complémentaire va à la capacité mensuelle et 75 % à la capacité journalière. Pour le sens Belgique-France, 50% de cette capacité complémentaire va à la capacité mensuelle et 50% à la capacité journalière.

59. La CREG note que, conformément à ses principes, la totalité de chaque capacité supplémentaire déterminée annuellement selon les formules de répartition est mise à disposition de l'enchère annuelle.

60. La réservation de capacité pour l'attribution journalière, lors de la détermination des capacités annuelles et mensuelles, est prévue explicitement au paragraphe 2.6 des orientations et est aussi présentée dans une note d'Elia et RTE de 2005 :[1] "la capacité

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[1] Enchères sur l'Interconnexion France-Belgique. Note d'accompagnement. le 22/11/2005

mensuelle disponible est la valeur maximale de capacité pouvant être garantie à l'horizon mensuel, d'un commun accord entre les deux GRTs, aux conditions définies dans les Règles IFB et en essayant de conserver un minimum de capacité à allouer à l'échéance journalière. Dans cette première approche, la capacité disponible pour l'échéance journalière serait alors la capacité supplémentaire dégagée au-delà de la valeur déjà allouée aux horizons annuel et mensuel, à laquelle s'ajoute, pour chaque heure de la journée suivante, conformément au principe du « Use-It-Or-Lose-It », la capacité non utilisée par les Participants ayant obtenu de la capacité sur des horizons de temps préalables au journalier. Toutefois, en vue d'assurer le bon fonctionnement du mécanisme d'allocation journalier, certaines contraintes sont susceptibles d'être intégrées aux calculs de capacités de manière à garantir des caractéristiques « minimales » à la capacité utilisée en journalier. Concrètement, 100 MW seront retenus avant détermination de la capacité annuelle disponible et 100 MW complémentaires seront retenus avant détermination de la capacité mensuelle disponible.". En outre, une capacité garantie attribuée à l'horizon journalier contribuera à un bon fonctionnement du marché par le biais du couplage de marché et à une convergence des marchés. Pour ces raisons, la CREG accepte le principe de réservation (limitée) de capacité à l'horizon journalier.

61. La réservation de capacité pour l'attribution mensuelle, lors de la détermination des capacités annuelles, est aussi présentée dans la note d'Elia et RTE de 2005. En outre, il ressort d'une étude de la CREG du 31 mars 2011[2] qu'une faible attribution des capacités à l'horizon mensuel peut engendrer une concentration du marché élevée. Pour ces raisons, la CREG accepte le principe de réservation (limitée) de capacité à l'horizon mensuel.

62. La CREG fait toutefois remarquer qu'Elia ne justifie pas dans sa proposition de répartition à partir de 2013 les pourcentages utilisés lors de la répartition de la capacité mensuelle complémentaire sur l'horizon mensuel et journalier, à savoir respectivement 25 % et 75 % pour le sens France-Belgique et 50 % et 50 % pour le sens Belgique-France. La CREG fait en outre remarquer que les participants à la consultation de marché en 2011 n'ont pas formulé d'objections au sujet de ce point particulier.

63. La CREG fait remarquer qu'en vertu de l'article 16.3 du Règlement, la capacité maximale des interconnexions doit être proposée aux acteurs du marché. Cela s'applique à

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[2] Etude (F) 110331-CDC-1050 relative au « fonctionnement du marché de gros belge pour l'électricité – rapport de suivi 2010 »

chaque échéance. La CREG prévoit qu'Elia utilise ce principe lors de chaque détermination de capacité sur ses interconnexions et propose au marché la capacité garantie la plus élevée possible pour chaque échéance.

64. La CREG fait remarquer qu'Elia, en collaboration avec RTE, a organisé une consultation des acteurs de marché sur les règles de répartition de la capacité le 29 juin 2011. La CREG soutient une telle initiative et demande d'être informée des futures consultations.

65. La CREG fait remarquer qu'elle a demandé, dans ses précédentes décisions relatives aux règles de répartition de la capacité, une justification de la répartition proposée qui tenait aussi compte de l'impact du mécanisme de transfert de la capacité non utilisée vers le couplage de marché par le biais du système Use-It-Or-Sell-It (UIOSI).[3] A l'annexe 2 de la proposition de répartition à partir de 2013, Elia et RTE simulent l'impact des règles de répartition proposées au moyen de trois paramètres, à savoir l'impact sur la convergence des prix au sein de la région CWE et entre la France et la Belgique, l'impact sur la capacité journalière disponible et l'influence sur les prix du marché. De la sorte, Elia répond à la demande de la CREG de justification du principe de répartition. La CREG demande à Elia d'utiliser à l'avenir cette étude complémentaire et d'éventuelles autres études pour justifier les principes de répartition.

66. Vu l'intérêt de certains acteurs du marché pour des droits de transmission financiers (FTR), la CREG a demandé à Elia dans sa décision du 10 novembre 2011 d'étudier l'impact de la mise en place éventuelle de ce type de produit. La CREG fait remarquer qu'Elia et RTE ont intégré la demande de FTR dans leur consultation de marché de 2011. Il en ressort que le marché estime qu'une approche régionale est indiquée et les acteurs du marché ont indiqué que l'introduction de FTR ne constitue pas une priorité absolue pour eux. Par ailleurs, la CREG constate que les gestionnaires du réseau de transport CWE ont réalisé une étude relative aux volumes et horizons de temps proposés, ainsi qu'une comparaison

[3] La décision (B)071122-CDC-729 du 22 novembre 2007 prévoit que : "L'efficacité de la mesure proposée par Elia est démontrée au moyen de simulations de l'évolution des capacités proposées au couplage des marchés résultant d'autres clés de répartition. Toutefois, ces simulations ne prennent pas en compte l'impact du report des capacités non utilisées vers le couplage des marchés (UIOLI) et de la revente des capacités annuelles et mensuelles (marché secondaire des capacités) au profit de la capacité journalière dont l'influence sur la capacité mise à disposition du couplage est clairement indiquée (407 MW en moyenne dans sens France vers Belgique pour la période de février à août 2007)."

entre "FTR options" et "FTR obligations". L'étude recommande, dans un premier temps, la mise en place d'options FTR. Par ailleurs, l'ACER achève d'ici la fin octobre 2012 une consultation de marché relative aux produits de long terme et au besoin d'harmonisation des règles d'enchères, des plates-formes informatiques et des procédures de nomination. La CREG demande à Elia de poursuivre l'examen de l'introduction de FTR, de vérifier quel en serait l'impact sur le marché et d'en informer la CREG.

67. La CREG constate que la règle de répartition actuelle a été acceptée dans son ensemble par les acteurs du marché. En outre, la CREG estime que la répartition proposée par Elia ne risque pas d'avoir un impact très négatif sur le marché si les valeurs NTC annuelles ne sont pas inférieures à celles des années précédentes.

68. Vu ce qui a été exposé dans les paragraphes 58 à 67 5766, la CREG peut approuver la proposition d'Elia de règles en matière de répartition de la capacité sur les différents horizons de temps à partir de l'année 2013.

69. La CREG demande à ELIA de systématiquement publier sur son site Web et de lui communiquer les valeurs NTC annuelles dès qu'elles seront connues.

70. La CREG demande à ELIA, pour chaque modification apportée à la méthode de répartition des capacités sur l'interconnexion Belgique-France, de lui en soumettre une proposition pour approbation. Cette proposition devra comprendre une justification de la répartition proposée (prise en compte de la structure du marché, du fonctionnement de Belpex depuis son lancement, du marché secondaire, de l'interaction avec les différentes frontières,…). Cette proposition doit également prendre en compte les études relatives aux droits de transmissions financiers.

71. La CREG estime que la répartition de capacité sur la liaison Belgique-Pays-Bas ne se trouve pas sa justification dans le Netcode Elektriciteit néerlandais et demande à ELIA de soumettre le plus rapidement possible une proposition de méthode pour la répartition des capacités entre les différents horizons de temps sur la liaison Belgique-Pays-Bas qui réponde aux exigences légales. D'une part, Elia renvoie dans sa lettre d'accompagnement et son annexe 3 ("la répartition des capacités BE-NL") au Netcode Elektriciteit néerlandais pour justifier la méthode de répartition des capacités utilisée sur les différents horizons de temps. D'autre part, Elia écrit dans une lettre du 25 juin 2012, faisant expressément référence au

Netcode Elektriciteit néerlandais, qu'elle ne s'estime pas compétente pour réaliser une analyse des textes de loi étrangers ("…Elia ne s'estime pas suffisamment habilitée que pour officialiser une analyse de dispositions issues de législations étrangères"). La CREG attend une proposition de méthode de répartition des capacités entre les différents horizons de temps sur la liaison Belgique-Pays-Bas qui réponde au cadre légal belge et européen détaillé en partie I.

72. Enfin, la CREG demande à ELIA (comme elle l'a fait pour l'année 2013) de publier systématiquement l'engagement des gestionnaires de réseau (RTE et ELIA) concernant le niveau minimal de la capacité qu'ils alloueront tout au long d'une année en novembre de chaque année précédant l'année concernée. Cet engagement doit avoir lieu suffisamment tôt pour être pris en compte par les acteurs du marché lors des enchères annuelles de capacités sur les deux frontières, soit avant la mi-novembre de l'année précédant l'année concernée.

DECISION

En application de l’article 23, §2, deuxième alinéa, 9° de la loi électricité et de l’article 180, §2, du règlement technique, la CREG décide, pour les motifs qui précèdent, d'approuver la proposition d’Elia relative aux méthodes de gestion de la congestion sur l’interconnexion Belgique-France, concernant les règles de répartition des capacités entre les différents horizons de temps à partir de 2013.

La CREG demande à ELIA de systématiquement publier sur son site Web et de lui communiquer les valeurs NTC annuelles dès qu'elles seront connues.

Afin de maintenir le même niveau de transparence concernant la capacité minimum garantie sur l’interconnexion Belgique-France, la CREG demande à Elia de publier, systématiquement au plus tard en novembre de l'année précédente, l’engagement des gestionnaires de réseau (RTE et ELIA) concernant le niveau minimum des capacités qu’ils alloueront tout au long d'une année conformément aux exigences formulées au paragraphe 72 71de la présente décision.

La CREG décide que la répartition de la capacité sur la liaison Belgique-Pays-Bas n'a pas de justification et demande à ELIA, comme indiqué aux paragraphe 7170, de lui soumettre dans les plus brefs délais une proposition de méthode de répartition des capacités entre les différents horizons de temps sur la liaison Belgique-Pays-Bas qui réponde aux exigences légales, par analogie avec la méthode pour la liaison Belgique-France.

La CREG demande à Elia de lui soumettre pour approbation une nouvelle proposition de répartition de la capacité pour chaque adaptation de la méthode. La proposition doit entre autres prendre en compte les exigences formulées aux paragraphes 66, 70 65et 71 6970de la présente décision.

Pour la Commission de Régulation de l'Electricité et du Gaz :

Dominique WOITRIN
Directeur

François POSSEMIERS
Président du Comité de direction

BIJLAGE 1

INTERCONNECTIE FRANKRIJK-BELGIË

METHODE VOORGESTELD VOOR DE VERDELING VAN DE CAPACITEITEN VANAF 2013

In overeenstemming met de bevindingen en conclusies vermeld in bijlage 2 leggen wij de volgende Methode voor de verdeling van de capaciteiten vanaf 2013 ter goedkeuring voor aan de CREG. Deze Methode werd niet gewijzigd ten opzichte van de methode voor de verdeling van de capaciteiten die gebruikt werd voor 2012:

1. Van de jaarlijkse NTC (NTCy) wordt een capaciteit van 200MW gereserveerd voor de maandelijkse allocatie (MAmin) en een capaciteit van 200MW voor de dagelijkse allocatie (DAmin) via marktkoppeling, terwijl de overige capaciteit als jaarlijkse ATC wordt toegewezen.

- ATCy=NTCy-MAmin-DAmin waarbij MAmin=200MW en DAmin=200MW

De hierboven genoemde verdelingsregel geldt in beide richtingen.

2. De overblijvende maandelijkse NTC (dit is de NTCm na aftrek van de ATCy en de capaciteitsreservaties voor maand- (MAmin) en dagallocatie (DAmin)), wordt als volgt verdeeld:

In de richting FR → BE: 25% aan de maandcapaciteit en 75% aan de dagcapaciteit
De maandelijkse ATC (ATCm) bedraagt dan:

- ATCm = MAmin + 0,25 (NTCm-ATCy-MAmin-DAmin)

In de richting BE → FR: 50% aan de maandcapaciteit en 50% aan de dagcapaciteit
De maandelijkse ATC (ATCm) bedraagt dan:

- ATCm = MAmin + 0,50 (NTCm-ATCy-MAmin-DAmin)

Indien de gereserveerde maand- en dagcapaciteiten niet beschikbaar zijn op het ogenblik dat de voor de maandelijkse veiling toe te wijzen capaciteit bepaald wordt, zal de beschikbare capaciteit gelijkmatig aan de maand- en dagcapaciteit toegewezen worden.

Alle hierboven vermelde verdelingsregels dienen te worden beschouwd los van eventuele capaciteiten bekomen tijdens een jaarveiling die door marktspelers te koop worden aangeboden in de maandveiling (zogenoemde "*resales*"). De hoeveelheid *resales* zal worden toegevoegd aan de ATCm.

Concreet levert deze methode voor de verdeling tussen jaar-, maand- en dagcapaciteit de volgende resultaten op voor verschillende NTCy- en NTCm-waarden in de richting van Frankrijk naar België (tabel 1) en van België naar Frankrijk (tabel 2).

In de richting van Frankrijk naar België:

NTC y	NTC m	ATCy	ATCm	DA	capacity ATCy+ATCm	capacity DA
1600	1600	1200	200	200	88%	13%
	1700	1200	225	275	84%	16%
	1850	1200	262,5	387,5	79%	21%
	1950	1200	287,5	462,5	76%	24%
	2150	1200	337,5	612,5	72%	28%
	2350	1200	387,5	762,5	68%	32%

NTC y	NTC m	ATCy	ATCm	DA	capacity ATCy+ATCm	capacity DA
1700	1700	1300	200	200	88%	12%
	1850	1300	237,5	312,5	83%	17%
	1950	1300	262,5	387,5	80%	20%
	2150	1300	312,5	537,5	75%	25%
	2350	1300	362,5	687,5	71%	29%

NTC y	NTC m	ATCy	ATCm	DA	capacity ATCy+ATCm	capacity DA
1850	1850	1450	200	200	89%	11%
	1950	1450	225	275	86%	14%
	2150	1450	275	425	80%	20%
	2350	1450	325	575	76%	24%

NTC y	NTC m	ATCy	ATCm	DA	capacity ATCy+ATCm	capacity DA
1950	1950	1550	200	200	90%	10%
	2150	1550	250	350	84%	16%
	2350	1550	300	500	79%	21%

NTC y	NTC m	ATCy	ATCm	DA	capacity ATCy+ATCm	capacity DA
2150	2150	1750	200	200	91%	9%
	2350		250	350	85%	15%

NTC y	NTC m	ATCy	ATCm	DA	capacity ATCy+ATCm	capacity DA
2350	2350	1950	200	200	91%	9%

Tabel 1: Jaar- Maand- en Dagcapaciteiten met voorgestelde methode voor de verdeling voor verschillende NTCy- en NTCm-waarden in de richting van Frankrijk naar België

In de richting van België naar Frankrijk:

NTC y	NTC m	ATCy	ATCm	DA	capacity ATCy+ATCm	capacity DA
600	600	200	200	200	67%	33%
	700		250	250	64%	36%
	800		300	300	63%	38%
	900		350	350	61%	39%
	1000		400	400	60%	40%
	1200		500	500	58%	42%

NTC y	NTC m	ATCy	ATCm	DA	capacity ATCy+ATCm	capacity DA
700	700	300	200	200	71%	29%
	800		250	250	69%	31%
	900		300	300	67%	33%
	1000		350	350	65%	35%
	1200		450	450	63%	38%

NTC y	NTC m	ATCy	ATCm	DA	capacity ATCy+ATCm	capacity DA
800	800	400	200	200	75%	25%
	900		250	250	72%	28%
	1000		300	300	70%	30%
	1200		400	400	67%	33%

NTC y	NTC m	ATCy	ATCm	DA	capacity ATCy+ATCm	capacity DA
900	900	500	200	200	78%	22%
	1000		250	250	75%	25%
	1200		350	350	71%	29%

NTC y	NTC m	ATCy	ATCm	DA	capacity ATCy+ATCm	capacity DA
1000	1000	600	200	200	80%	20%
	1200		300	300	75%	25%

NTC y	NTC m	ATCy	ATCm	DA	capacity ATCy+ATCm	capacity DA
1200	1200	800	200	200	83%	17%

Tabel 2: Jaar- Maand-, en Dagcapaciteiten met voorgestelde methode voor de verdeling voor verschillende NTCy- en NTCm-waarden in de richting van België naar Frankrijk

ANNEX 2

FRANCE-BELGIUM INTERCONNECTION

ALLOCATION AND UTILISATION OF CAPACITIES

OBSERVATIONS AND ANALYSES 2011-2012

Table of Contents

1 Executive Summary

1.1 Context and Content of the Study

In accordance to CREG Decision (B)111110-CDC-1123 of November 10th 2011 Epigraph 63, where CREG requests ELIA to submit (by October 15th 2012 as the latest) a proposal for the Split Rules at the French-Belgian Border contemplating: a justification of the proposed split taking into consideration all the aspects related to the market structure and the potential implementation of Financial Transmission Rights; the following study is presented.

This report analyses the allocation and utilization of interconnection capacity at the French-Belgian border in both directions. For this particular border, the report studies: cross-border capacity availability, split of capacity among products, capacity utilization and prices of auctioned capacity. The functioning of BELPEX is also considered. RTE and ELIA use the results of these analyses in order to make a proposal for the capacity split among yearly, monthly and daily products.

Additionally, an update on the studies performed on Financial Transmission Rights (FTR) and their potential implementation (options and obligations) accompanies this report. Different sensitivities are conducted on the capacity split in order to check its market efficiency on all the Belgian borders.

1.2 Conclusions of the Study

The main conclusions of the study are:

- Generation capacity availability and demand-side fundamentals remain being the main elements determining the prices paid for capacity at explicit auctions and also the day-ahead market spread

- On average, from January 2011 until June 2012 (end of the study period) Belgium has been a net importer and also a transit area for further French exports towards Germany and the Netherlands. This represents a change with respect to the prior trend, under which, Belgium was mainly exporting to France. In fact, between June 2009 and May 2010 there had been a positive spread in the direction from Belgium to France, mainly driven by low French nuclear availability combined with high French demand levels. The main drivers for this change have been several:

    - On one side, French demand decreased in 2011 due to mild temperatures. French demand is very sensitive to thermal conditions (demand varies following an inverse proportion 2300 MW/°C, in the winter and measured at the 19 hours peak). Year 2011 has been the warmest in France since 1900, after a rather cold 2010

    - Additionally, the economic crisis has contributed to further decrease French local demand since 2008-2009. After a temporary rebound in 2010, there has been a relapse of downward trends since January 2011. This reduction has been mainly driven by big industry. Sustained growth in the households and services has not managed to compensate this effect. All this has led to an overall French demand reduction of 6.8% in 2011 when compared to 2010, bringing annual consumption back to a level of 478.2 TWh (only comparable to these in 2003). When combining this with the base-loaded French nuclear generation park this means automatically cheaper power available for export

- High gas spot prices have also favoured exports to the Netherlands (much more sensitive to this factor), since this country has a generation mix completely different from the French (and Belgian) one, where nuclear production prevails

- Exchanges with Germany have been severely impacted by the German decision to shut down 7 of their nuclear units (German Nuclear Moratorium). This has produced a reversion of the price spread between France and Germany. As from March 15th 2011 France is prevailingly cheaper than Germany in the spot. Forward prices have only accused this effect as from May 30th (the moment Germany took its final decision to exit nuclear power). Within the intraday, French exports take mainly place during the night, when German photovoltaic is not active and, especially when wind production in this latter country is low

- As a result of all this shifts France exported 55.7 TWh (net value) in 2011 (89% more than in 2010). This was composed of an export increase of 13% (reaching a level of 75.4 TWh) and (overall) an import decrease of 47% (going down to a level of 19.7 TWh). France was net exporter to Belgium in all months of 2011, with the exception of some very weak net importer position in October 2011. Prices between these two markets have been coupled most of the time (>90%)

- Year 2012 has seen a continuation of all these trends, with one major exception. This was the European Cold Wave 2012, which took place during the month of February 2012. In France this has been one of the three more severe cold waves of the last thirty years and the fifth in the ranking since 1947. February 1st to 15th saw the most raw climate conditions of the cold wave in France.

  - The main reason why this event affected France differentially is French heating patterns. Contrary to other European countries (mainly reliant on natural gas and bunkers for heating), in France, around 35% of all households are heated with electricity (figure for 2010). Combined with this accrued thermal sensitivity of the French demand, the step decrease in temperatures during the first half of February led to an immediate overcome of the historical 100 GW consumption benchmark, attaining an all-time record demand of 102.1 GW during the afternoon/night of February 8th 2012 (of which 38% was thermic-driven). This represented the expected peak consumption level for the winters of 2013-2014 in France

  - Under these conditions all French production capacity had to be called in. Only 3 out of 58 nuclear units where under maintenance in France and only 5 out of the around 400+ thermal conventional ones, which increased their participation share in the merit order from 10% to around 15-20% in selected periods of the wave. Hydro levels at reservoirs were within the ten year average for this period of the year; after the cold wave, they were at their lowest level for 20 years due to the hydro contribution to ease demand. French wind covered between 2 and 2.5% of demand during the wave on average

  - Due to all prior, France had to import during the month of February, contrary to the prevailing trend since France is a net exporter during most of the rest of the study period. The French maximum import capacity was used (exceeding 9 GW on

February 9th at 9 hours). German wind capability to meet French demand was rather reduced due to wind scarcity in this country caused by a different behaviour of the weather front in this country. German photovoltaic contributed a little bit more, but only during day-time

- Demand reduction measures were called in France but in spite of the system working generally well and system security margins being respected, it could not be avoided that a peak of 2000 €/MWh (the maximum registered market price level during February 2012) was reached at EPEX Spot on February 9th between 10 and 11 hours (with an average of 367 €/MWh during the day). Other peaks of around 300 €/MWh were reached during February 6th and 7th, respectively and of more than 500 €/MWh on February 10th 2012. The other countries in the CWE area remained at high fluctuating levels, but not overcoming the 125 €/MWh in the spot for the same period

- The Cold Wave made however prices in the CWE area diverge during 80% of the duration, left the French market isolated from its neighbours during more than one third of the time it lasted and has had a very clear impact in the shared order books that are used for the simulations conducted in this document. In general terms, since the study horizon used compares 2011 (full year) to 2012 (half a year roughly), the impact of this Cold Wave can be appreciated in almost all figures, as the important temporary trend change it represented for France and all its neighbouring countries, Belgium included

- On the FR→BE direction, the average NTCd-1 was 2872 MW in 2011. Until June 2012 the average NTCd-1 was 3115 MW. The average ATCd-1 increased 12% from 2547 MW in 2009 to 2680 MW in 2010. In 2011, the ATCd-1 remained at an average of 2698 MW and has registered a higher average of 2933 MW from January until June 2012. On average 95% of the allocated year and month capacity rights in 2010 (until November 10th) was resold in the day-ahead market. From November 10th until end of July 2011, the resales dropped to 87%. In 2012 (until June), on average 86% of the allocated year and month capacity rights were resold. The ratio nominated to allocated long term capacity increased from approximately 3% in 2010 to 13% in 2011 and has stayed more or less at the same level for 2012.

- On the BE→FR direction the average NTCd-1 was 1415 MW in 2011. From then on, until June 2012, the average NTCd-1 has been 1728 MW. The average ATCd-1 remained stable from 1040 MW in 2009 to 1025 MW in 2010 and increased to 1613 MW in 2011. In 2012, until June, it was on average 1916 MW. On average 72% of the allocated year and month capacity rights in 2010 (until November 10th) were resold in the day-ahead market. From November 10th up to the end of 2011, resales increased to 91%. In 2012, until end of June, the resales slightly increased up to 93%. The ratio nominated to allocated long term capacity decreased from approximately 28% in 2010 to 9% in 2011 and decreased further to 7% in 2012. The directional switch from 2011 onwards with France exporting to Belgium clearly impacts the long term nomination behaviour of Market Participants. These are physically using their long term allocated rights, even in the absence of (significant) price spreads between France and Belgium but in the perspective of higher price spreads between France and Germany, with the exception of the Cold Wave period.

- In general terms it can still be observed a positive correlation between the market spread and the nomination behaviour. The higher the spread, the more the yearly and monthly capacity is nominated . More specifically, since January 2011 the absence of congestion in the direction FR→BE results in bilateral coupling. Hence, the price spread between Belgium and the Netherlands is the driving factor behind these long term nominations on the BE→FR border. Since the announcement of the German Nuclear Moratorium on March 15th 2011, the import from France is to a very large extent exported to the Netherlands (and further to Germany), trend which has been maintained for 2012

- Daily capacity is very important to couple the bidding zones of France, Germany, Belgium and the Netherlands. The price convergence between France and Belgium was 70%, 85% and 63% respectively for the periods 2009, 2010 (till November) and November 2010 till the end of 2011. In 2011, we measure a convergence rate of 99.5% between France and Belgium. In 2012 (until the end of June), this price convergence was 46% on average between all CWE market, but 93 % between France and Belgium. This former effect is temporary (driven by high gas prices) and also reflects, among others, the impact of the Cold Wave.

- Apart from the aspects mentioned in this summary there have been no detected changes to market fundamentals or to the observed market parties behaviours, with respect to the ones of the last study period, which involved 2010 and 2011

- During 2012 a study has been performed at CWE level regarding the potential introduction of FTR in the CWE area and the procedural and technical changes that this would represent. The particulars of this study, conducted in coordination with all involved TSOs are presented in Chapter 6 of this document. At the same time, ACER has launched a market consultation on long term hedging products, whose results will only be known by the end of October 2012 (coinciding with the presentation of this report).[1] The main content of this consultation is also commented in Chapter 6. The consultation has been accompanied by the distribution of an Educational Paper on Long Term Transmission Rights prepared by ENTSOE.[2] The paper contains no ENTSOE position and is just meant to be an informative note on how the different products work and their respective potential impact on the market. In coordination with the involved stakeholders, TSOs and NRAs, CWE may see a pilot experience of FTR options at one of its external borders (Germany-Denmark) by 2013. This possibility is further mentioned at Chapter 6. Taking into consideration all the previous, the simulations for the proposed Split Rules using the shared order books for the study period, have also been performed with zero nomination levels (within Chapter 7). This tries to roughly approximate some of the effects of FTR introduction.

- Following a coordinated process involving all the CWE TSOs, the year NTC will be determined early November 2012. Hence, it is not possible to provide any indications about the foreseen level of NTC for 2013 in the framework of this split rule proposal for 2013 and beyond.

[1] ACER consultation documents can be found under the following link:
http://www.acer.europa.eu/Official_documents/Public_consultations/Pages/PC_2012_E_13.aspx

[2] This paper can be found at ENTSOE website under the following link:
https://www.entsoe.eu/fileadmin/user_upload/_library/consultations/Network_Code_CACM/20120619_Educational_Paper_on_Risk_Hedging_Instruments_review5.pdf

1.3 Proposed Split Rule for Cross-Border Capacity at the French-Belgian Border

On the basis of the analyses and the simulations detailed in this document (regarding split rules performance), taking into consideration that the general market framework is the same as during 2011 (no changes in terms of products, regional coordination initiatives, or structural market conditions) and that no feedback has been received from market parties in the opposite direction, ELIA and RTE propose to keep the current Split Rules (an extensive description of these can be found in Section 8). A brief summary follows:

- From the yearly NTC, reservation of 200 MW capacity for the monthly allocation (MAmin) and 200 MW of capacity for the daily allocation (DAmin) (through market coupling), the remaining capacity being allocated as yearly ATC

    - ATCy =(NTCy −MAmin −DAmin); with MAmin =200 MW and DAmin =200 MW

  The aforementioned Split Rule holds for both directions

- The remaining monthly NTC (i.e. the NTCm after deduction of the ATCy and capacity reservations for month (MAmin) and day allocation (DAmin)) is split as follows:

  In the direction FR → BE: 25% to the monthly capacity and 75% to the daily capacity
  The monthly ATC is then equal to:

    - ATCm =MAmin +0,25 (NTCm −ATCy −MAmin −DAmin)

  In the direction BE → FR: 50% to the monthly capacity and 50% to the daily capacity
  The month ATC is then equal to:

    - ATCm =MAmin +0,50 (NTCm −ATCy −MAmin −DAmin)

In case the reserved capacities for month and day-ahead are not available when determining the capacity to allocate at the monthly auction, the available capacity will be equally allocated to the month and daily capacity.

All the above-mentioned Split Rules must be considered independent from any capacity resale from year to month (any resale from year to month will be added to the ATCm).

The reasons for the difference in the repartition between monthly and daily capacity of the remaining month NTC for the directions BE→FR (50/50) and FR→BE (25/75) are the following ones.[3] During the last market consultation (performed in 2011) market parties expressed their wish to have several simultaneous features implemented with respect to the previous French-Belgian Split Rules 2010-2011. These features are related to the above-mentioned different repartition in the way that will be explained below. The desired features by market parties were mainly:

[3] CREG Decision (B)111110-CDC-1123 of November 10th 2011 Epigraph 55 highlighted the fact that the 2011 Split Rules Proposal did not explain the different percentages for each direction, but also mentioned that (in any case) market participants seemed to be in line with this difference (via the performed market consultation), the explanation that follows elaborates on this point further, showing that this difference was actually set up in order to be able to comply with several simultaneous preferences from market parties.

- That no fundamental changes should be made to the prior set of Split Rules (2010-2011)
- To facilitate a good DA functioning and sufficient liquidity through the assignation of enough capacity to market coupling in the split (since this provides good signals to forward markets)
- Simultaneously, try to increase the amount of capacity available in the long term (MA, YA)
- Ensure the availability of at least 200 MW for MA (both directions); the perception was that the amount being reserved for YA was already proportionally enough
- Finally, introduction of more symmetry between both directions

The incorporation of all these wishes from market parties implied the definition of a compromise solution for 2012, which we propose to keep for the future.

Whilst introducing no radical changes to the previous Split Rules used during 2011, this compromise solution for the Split Rules of 2012 (maintained also for the current proposal of Split Rules) increased the capacity available for monthly allocations (thus increasing the proportional share of the long-term where market parties were demanding it). This was done respecting the minimum capacity requirements of market parties for monthly allocations (200 MW) and introducing (at the same time) more symmetry between both directions by increasing the MAmin reservation for the direction FR→BE from 100 to 200 MW and reducing the DAmin reservation from 400 to 200 MW (MAmin and DAmin became then equal to those for the opposite direction BE→FR). The amount of 200 MW (YA-to-MA resale excluded) in the direction FR→BE is superior to the 150 MW required to break the correlation between the amount of cross border capacity offered at the monthly allocations and the Herfindahl-Hirschman Index for concentration of the monthly allocations results for this direction (as per the CREG Study (F) 110331-CDC-1050, Page 49). The repartition 25/75 rule in the remaining monthly NTC was kept in order to avoid any structural break or fundamental changes, in virtue of the simultaneous wishes expressed by market parties (above).

ELIA and RTE believe that the proposed Split Rules:

- Introduce enough symmetry between import and export
- Allocate an adequate share of capacity to the long term horizon
- Prove to be robust and not disruptive when tested with current market outcomes
- Comply with the last feedback received from market parties, under similar market fundamentals, conditions and detected behaviours than those that are prevailing nowadays
- Make due consideration of the observations made by the CREG regarding the functioning of the auctioning of monthly capacity rights for the French-Belgian border

Simulations based on historical orders books and NTCs indicate that the proposed Split Rule does not significantly impact the price convergence within the CWE area, even in case of some important modifications of the behaviour of market participants (higher nomination ratios compared to the current ones). Simulations have also been performed without any nomination in order to very preliminarily estimate what the potential immediate effect of FTR options introduction could be under the proposed Split Rules for market convergence in CWE and more particularly for the French and Belgian market. FTR would also entail other important market effects (non-measurable through this simulation), but this provides already some considerations and an order of magnitude for some of the effects, in combination to the other Studies which are mentioned within Section 6.

This proposal for capacity split is independent from the value of the available NTCy on the BE-FR border, as this latter one will be determined following a coordinated process between all CWE TSOs during early November 2012.

2 Introduction

2.1 Definitions and Process

Different definitions are used. This is a brief description of the most important ones:

- Net Transfer Capacity (NTC): the NTC is the maximum total exchange program between two adjacent control areas compatible with security standards applicable in all control areas of the synchronous area, and taking into account the technical uncertainties on future network conditions

- Available Transfer Capacity (ATC): is a measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. ATC is the part of NTC that remains available after each phase of the allocation procedure for further commercial activity

- Allocated Capacity: the capacity that has been obtained by the market parties

- Nominations: the exchange program that the market parties must send to the TSOs in order to use their allocated capacities

Interconnection capacity is allocated using different timeframes and methods. At the French-Belgian border the capacity is offered as:

- Yearly products (a fixed capacity for all hours of the year)
- Monthly products (a fixed capacity for all hours of the month)
- Daily products (a capacity for each specific hour of the following day)
- Intraday products (a capacity for each specific hour during the day)

The capacity is calculated and allocated for each direction separately, this means from Belgium to France and from France to Belgium. Yearly and monthly products are allocated through explicit auctions. Daily products follow an implicit auction procedure. Indeed, daily capacities are used to couple the day-ahead markets of France, Belgium and the Netherlands (TLC). From November 9th 2010 onwards, the CWE Market Coupling is in place, meaning the day-ahead markets of Belgium, France, the Netherlands & Germany are being coupled via implicit auctions. Intraday uses explicit allocation.

The Split Rules decide which part of the capacity is reserved for which product (year, month, and day).

After the closure of the day-ahead procedures the TSOs will assess if there is still capacity left. This capacity will be allocated to the market through an intraday allocation mechanism. Because there is no capacity reserved for the intraday mechanism, it will not be discussed in this document.

The capacities are calculated for each allocation phase:

- The yearly NTC (NTCy) gives the capacity that is expected during all hours of the year.
- Each month, a monthly NTC is calculated (NTCm). The monthly NTC gives the capacity that is expected during all hours of this month
- Finally a day-ahead NTC (NTCd-1) is calculated. The day-ahead NTC gives for each hour of the following day the capacity available for the market taking into account the safety of the grid within the CWE region. The accuracy of the day-ahead NTC will be higher than

the monthly NTC and the yearly NTC because the moment of calculation is closer to the time of the physical transaction (real time)

Whilst calculating the daily ATC TSOs apply the principle of netting. This means that they take into account the netted values of the yearly and monthly nominations.

2.2 Context

Since 2007, RTE and ELIA have proposed to their respective Regulators rules to split the capacity on the France-Belgium border among the different allocation timeframes (yearly, monthly and daily). These proposals were based on a detailed analysis of the allocated and used capacities in the market.

For the current capacity Split Rules proposal, ELIA and RTE have performed analyses based on the results of the French–Belgian capacity allocations held from January 2011 till June 2012 in both directions. These analysis are based on:

- Levels of capacity proposed at the different timeframes
- Allocated capacity and prices
- Usage of capacities (nominations)
- Price convergence levels within CWE market coupling

Since November 2009, the "Use-it-or-lose-it" (UIOLI) principle and the resale of yearly and monthly capacities to the daily allocations within the CWE Region have been replaced by the "Use-it-or-sell-it" (UIOSI) principle. This means that all non-nominated yearly and monthly capacities will be automatically resold to the daily capacity allocation. Yearly resale to the monthly market only takes place if there is an explicit refusal of this capacity by its holder and for the whole month in question as a block.

Following a coordinated process involving all the CWE TSOs, the year NTC is determined during early November 2012. Hence, it is not possible to provide any indications about the foreseen level of NTCy for 2013 in the framework of this Split Rules proposal.

3 Split Rules 2012

The Split Rules that were effectively applied in 2012 are the same as those that ELIA and RTE propose for application as from 2013; a brief description follows.

3.1 From France to Belgium

The capacity was split as follows:

- For the 2012, NTCy in the direction France to Belgium was equal to 1850 MW. 200 MW have been reserved for the MAmin and 200 MW for the DAmin. The remaining 1450 MW have been assigned to the ATCy for the yearly auction (computation at Column 2 in the Table hereunder).
- If the minimum monthly and daily capacities (above) are not available when determining the capacity to allocate to the monthly auction, the available capacity is equally allocated to the month and daily capacities. Conversely, capacity surpluses when determining the capacity to allocate to the monthly auctions, are allocated according to the following sharing principle: 25% is given to the monthly auction and 75% to the daily market coupling. These additional volumes are calculated before the integration of the resale of yearly capacities to the monthly auctions (which are added to the ATCm later on).

FR → BE NTCm	Yearly Capacity (ATCy)	Monthly Capacity (MA)	Daily Capacity (DA)	YA+MA Capacity (%)	DA Capacity (%)
1850	**1450**	**200**	**200**	**89%**	**11%**
1950	1450	225	275	86%	14%
2150	1450	275	425	80%	20%
2350	1450	325	575	76%	24%

Table 1: Illustrative Examples of Capacity Repartition with NTCy FR→BE Value in 2012, under Different Scenarios for the Value of NTCm

Concretely, this repartition produces the split between yearly capacity (ATCy), monthly capacity (MA) and reserved daily capacity (DA) that is displayed in Table 1 (above), for different possible values of monthly NTC in the direction France to Belgium.

3.2 From Belgium to France

The capacity is split as follows:

- For the 2012, NTCy in the direction Belgium to France was equal to 800 MW. 200 MW have been reserved for the MAmin and 200 MW for the DAmin. The remaining 400 MW have been assigned to the ATCy for the yearly auction (computation of the column 2 in the table hereunder).
- Same case as in the opposite direction, if the capacity required for the minimum monthly and day-ahead capacity levels is not available when determining the capacity for the monthly auction , the available capacity is equally allocated to the month and daily timeframes
- Conversely, capacity surpluses when determining are allocated according to the following sharing principle: 50% is given to the monthly auction and 50% to the daily market. These additional volumes are calculated before the integration of the resale of yearly capacities to the monthly auctions (which are added to the ATCm later on).

BE→FR NTCm	Yearly Capacity (YA)	Monthly Capacity (MA)	Daily Capacity (DA)	YA+MA Capacity (%)	DA Capacity (%)
800	**400**	**200**	**200**	**75%**	**25%**
850	400	225	225	74%	26%
900	400	250	250	72%	28%
1000	400	300	300	70%	30%

Table 2: Illustrative Examples of Capacity Repartition with NTCy BE→FR value in 2012, under Different Scenarios for the Value of NTCm

This repartition produces the split between yearly capacity (ATCy), monthly capacity (MA) and reserved daily capacity (DA) that is displayed in Table 2 (above), for the different possible values of monthly NTC in the direction Belgium to France.

The average of hourly NTCs (NTCd-1) is depicted on a monthly and a yearly basis in Table 3. During the first months of 2012 the average NTCd-1 has varied between 2828 MW and 3364 MW in the direction FR→BE and between 1349 MW and 2133 MW in the direction BE→FR. The pre-calculated year NTC values of 1850 MW (FR→BE) and 800 MW (BE→FR) are below these averages.

	BE→FR NTCd-1 (MW)		FR→BE NTCd-1 (MW)	
Date	**Average**	**Minimum**	**Average**	**Minimum**
Year 2011	**1418**	**800**	**2886**	**1800**
01-2011	1422	1300	3530	3200
([4]) 02-2011	1405	1300	3314	3000
03-2011	1560	1400	3167	2500
04-2011	1058	800	2745	1900
05-2011	1274	1000	3004	2100
06-2011	1200	1200	2533	1800
07-2011	1200	1200	2566	1900
08-2011	1218	1000	2665	2100
09-2011	1431	1000	2685	2000
10-2011	1773	1700	2674	2400
11-2011	1732	1400	2875	1900
12-2011	1748	1800	2878	2800
Year 2012	**1728**	**800**	**3115**	**2000**
01-2012	1735	1400	3002	2000
02-2012	1664	1500	2828	2500
03-2012	1906	1700	3285	3200
04-2012	2133	1600	3105	3000
05-2012	1583	800	3364	2800
06-2012	1349	1000	3106	2400

Table 3: Average and Minimum Daily NTCd-1 Capacities at the BE-FR Border

[4] February 4th and 5th 2011 have been excluded.

4 Observations and Analysis

4.1 Available Capacity and Use: General View

Figure 1 and Figure 2 set out, respectively for the direction France to Belgium and Belgium to France the amount of yearly, monthly and daily ATC, as well as the day ahead NTC for 2011 and 2012 (end of June). The monthly capacity value does not include any potential resale from the yearly auctioned capacity, whereas the day ahead capacity value does include the resold year and month capacities following the UIOSI principle.

In both directions, it can be observed that NTCd-1 is lower during the summer than during the winter. This cyclical pattern is mainly due to physical conditions linked to temperature and its effects on the cables. The available month capacity is following the same pattern, consequently.

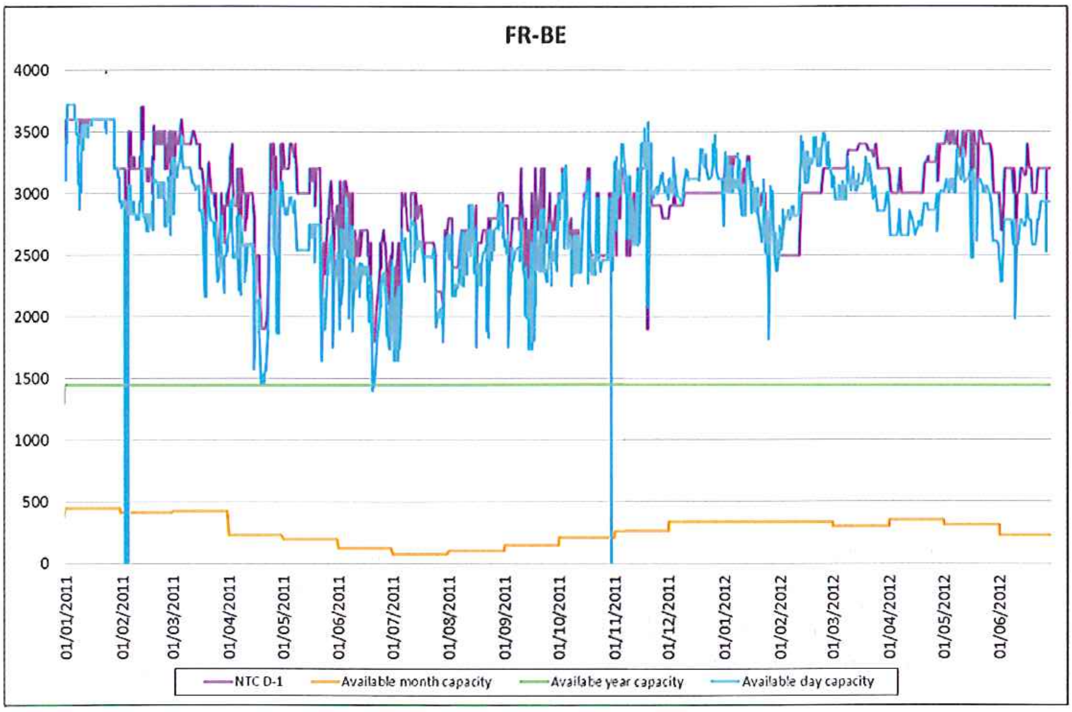

Figure 1: NTCd-1, Available Year, Month and Day Capacity in the Direction France to Belgium

The most important observed off-peaks in Figure 1 correspond to the exceptional reduction that took place on February 4th and 5th 2011 and to the regular long clock change (exit from summer time) procedure on October 30th 2011 (this procedure will change in 2012). The operational objective of providing 2000 MW in this direction during 95% of the time and up to 2200 MW during 90% were both significantly overcome with 98% and 94% achieved respectively.[5]

In 2011, until October, and in 2012, as from March, the NTCd-1 FR→BE is higher than the ATCd-1 due to long term nominations in the same economic direction (FR→BE). From November 2011 until March 2012 the NTCd-1 FR→BE was mainly lower than the ATCd-1 due to nominations in the opposite direction BE→FR. This is because of the use of the netting principle for the determination of the ATCd-1. This is supposedly and amongst other reasons, due to the German nuclear moratorium causing long term nominations from FR→BE that result in export flows from France to Belgium

[5] When taking into consideration all the reduction events. These percentages are operational objectives for ELIA, meaning that (in practice) only Belgian events should be computed for their compliance, which implies the unilateral compliance percentages may be different from these (higher or equal by definition).

(transiting to the Netherlands and finally to Germany). The opposite relationship between NTCd-1 and ATCd-1 can be observed in the direction BE→FR.

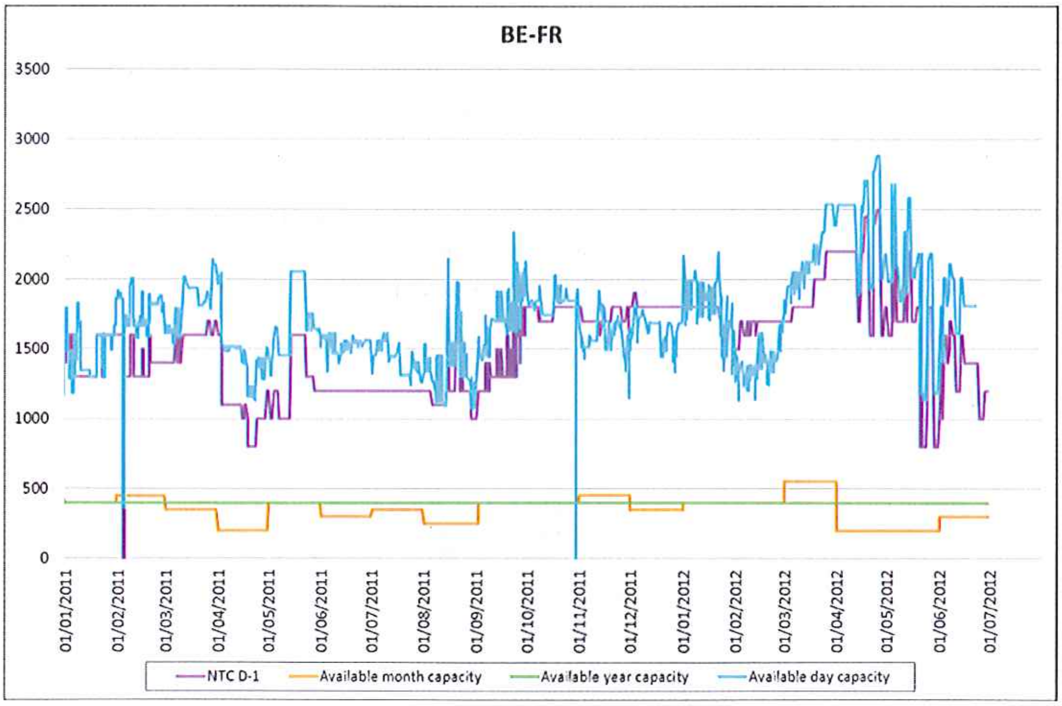

Figure 2: NTCd-1, Available Year, Month and Day Capacity in the Direction Belgium to France

Figure 3 and Figure 4 illustrate the import/export nominations of allocated capacity ("Nominations Total" includes the day-ahead flows and the intraday, monthly and yearly nominations) and, thus, the specific use of the allocated yearly and monthly capacities in comparison to the available (fully allocated) yearly and monthly capacities for the auctions. As it can be seen, on the period November 2011 to March 2012, there is a directional swift from long term nominations from FR→BE to BE→FR resulting in low use of long term available capacity in the direction FR → BE during that period.

In 2011, the nominated import into Belgium from France ("Nominations Total") averaged at 899MW per month whereas from January 2012 till June 2012, the total nominated import into Belgium increased to an average of 1285MW per month. The monthly average long term nominated share was of 240MW for 2011 and 238MW for 2012 (end of June).

The nominated export from Belgium to France (again Nominations Total) in 2011 was on monthly average 236W and increased to 355MW per month in 2012 (end of June). This latter was mainly due to the consumption peak in February 2012 (caused by the European Cold Wave which provoked in particular a consumption peak in France of 102 GW on the evening of February 8th). The long term nominated share slightly increased from a monthly average of 48MW in 2011 to 60MW in 2012 (end of June). For January and February, the long term nominated share is on average 172MW and drops significantly to on average 5MW from March until end of June. All for the very same reasons: cold wave and high consumptions in France, where large part of the heating systems are electric –in contrast with Belgium. The impact of the cold wave was also strong in France due to the fact that the nuclear availability in this country was comparatively lower during the month of February than the one of the previous year (88.53% in February 2012 instead of the 91.45% that had been registered in February 2011).

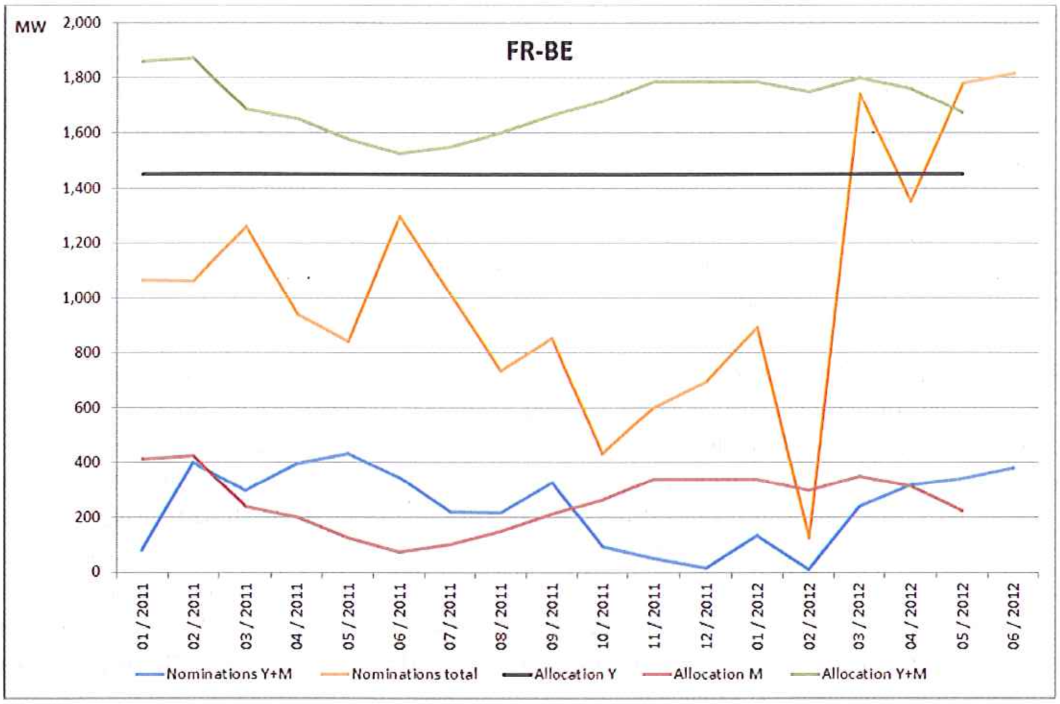

Figure 3: Nominated Capacities and Available Year and Month Capacity in the Direction France to Belgium

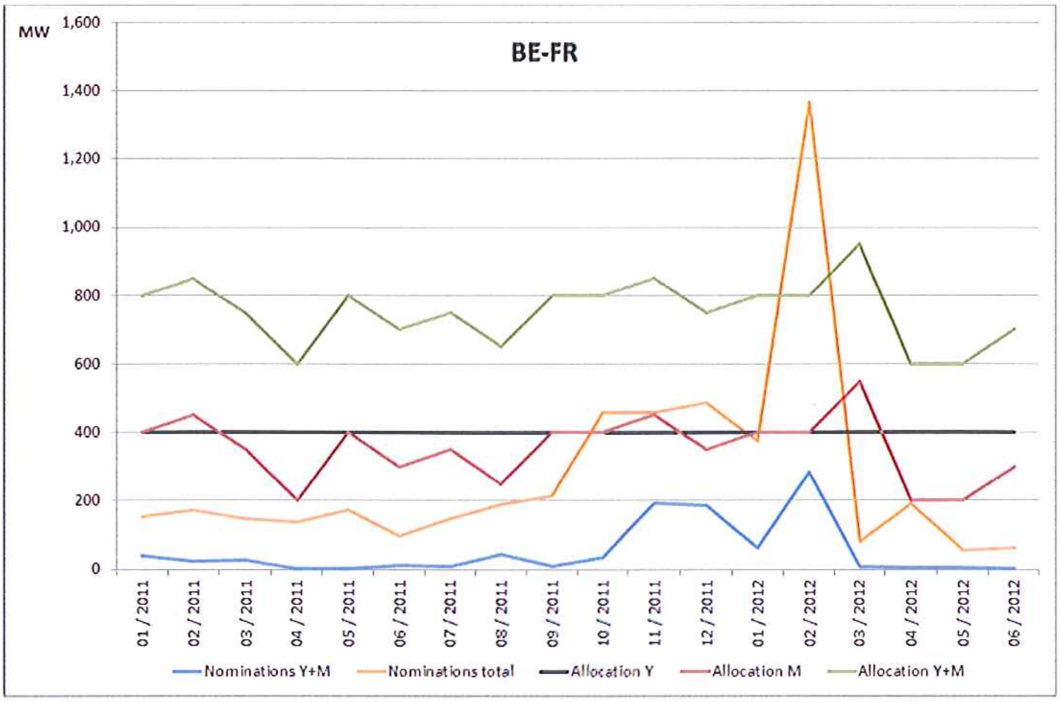

Figure 4: Nominated Capacities and Available Year and Month Capacity in the Direction Belgium to France

Hence, on the BE-FR border from 2011 to 2012 (end of June) the yearly and monthly import (nominations) into Belgium increased by 386 MW (just by comparing the averages for both years) and suffered a structural break with a decrease from the 1st of February 2012 until the 29th of February 2012 except for the period 16th until 17th of February 2012, just by the end of the 2012 European Cold Wave. All this with the long term nominated share remaining more or less stable at around 250 MW on monthly average. The monthly average export from Belgium into France (and, again, comparing both years) increased by 120 MW, but this was only on average and due to the presence of a peak of almost 1400 MW in total nominations in this direction during February 2012 (for the reasons above and representing almost 1000 MW additional to the prior month). The total nominations decreased immediately to a much lower level of around 200 to 100 MW and below in the months after. All prior, with a long term nominated share that neared zero as 2012 (end of June) was being approached.

When comparing all the previous to the import /export flows on the BE-NL border in Figure 5 and Figure 6, we observe the following.

Imports from the Netherlands into Belgium (Figure 5) have a seasonality pattern. Most imports take place during the autumn and winter months and get progressively reduced by spring time (reaching a lower limit in the summer). There is a peak of almost 1200 MW on the monthly average coinciding with the peak in French imports from Belgium in February 2012 (that totaled almost 1400 MW on monthly average during the same period due to the cold wave impact). Therefore, this may let us conclude that of the previous 1400 MW exported from Belgium to France, a considerable part of them were energy in transit towards France from other CWE countries or beyond. Long-term nominations for imports from the Netherlands into Belgium have remained on monthly average under 200 MW. They only slightly overcome this level during the winter and usually stay close to zero during summertime.

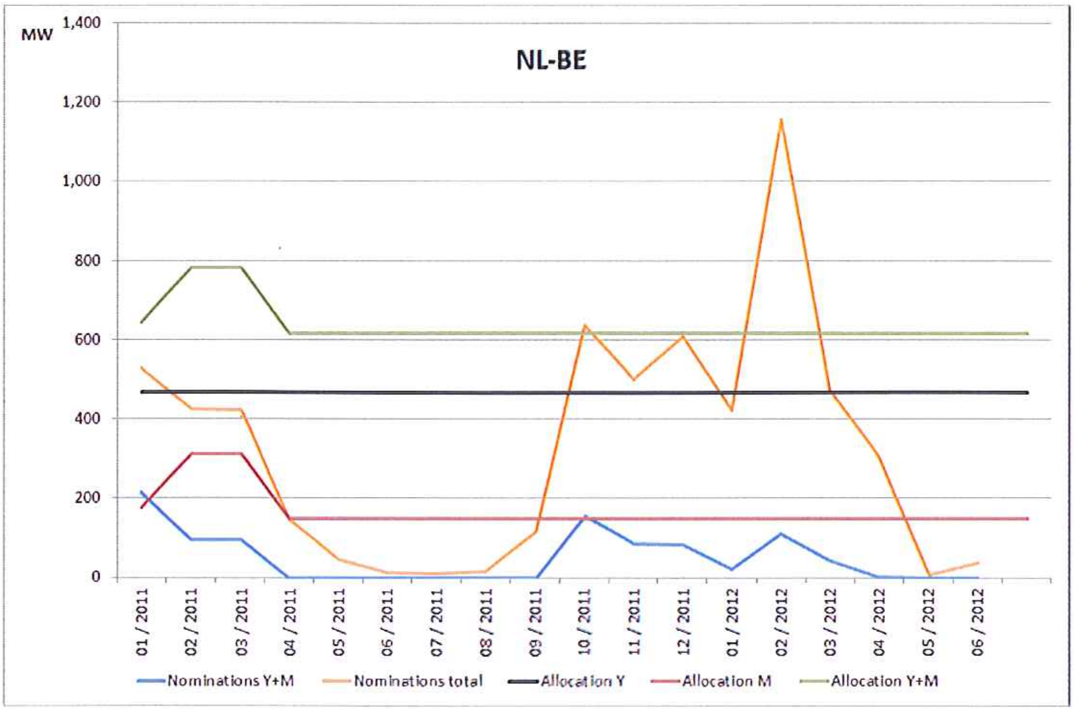

Figure 5: Nominated Capacities and Available Year and Month Capacity in the Direction the Netherlands to Belgium

Exports from Belgium into the Netherlands (Figure 6) work with the opposite seasonal pattern than above (peaking in the summer). This is in part caused by the characteristics of the Belgian system (relatively small with a considerable participation of base-loaded big nuclear units and a consumption off-peak in the summer); during the summer Belgium is usually long in base load, which favors exports to countries with another fuel mix (less nuclear) like the Netherlands. During the winter the mechanism gets reversed, gas prices permitting. Exports towards the Netherlands may raise from monthly average levels of around 500 MW in the winter (with zero long term nominations) to around 1200 MW in the summer (with around 200 MW long term nomination in this direction).

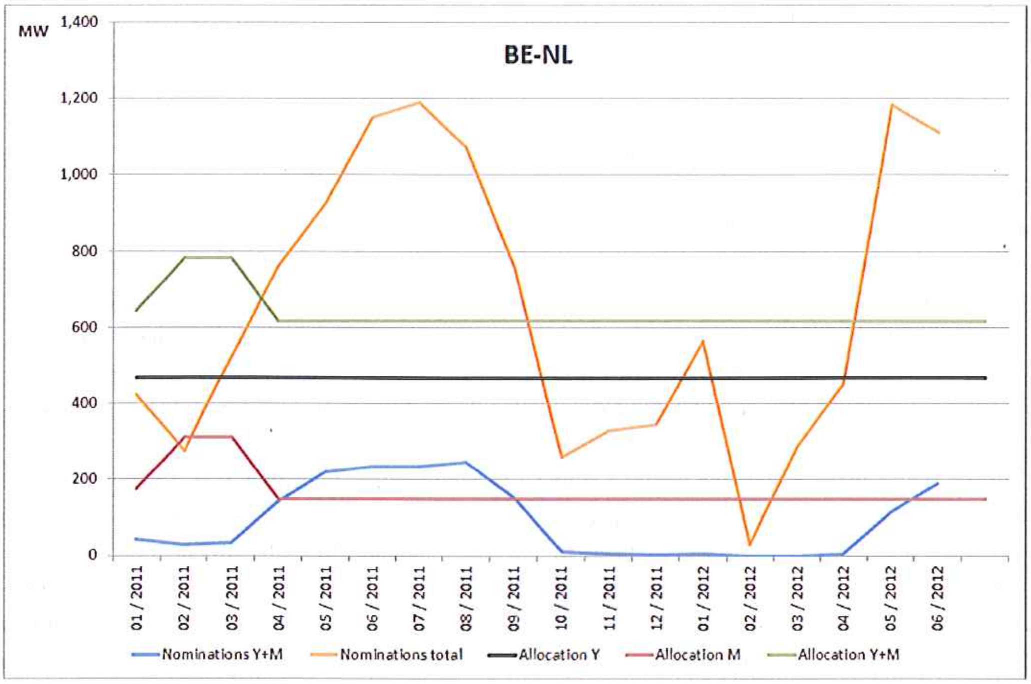

Figure 6: Nominated capacities and available year and month capacity in the direction Belgium to the Netherlands

Figure 7 below illustrates the evolution of the average daily NTCd-1 since January 2011 till June 2012, as well as its average utilization. The positive values show the export from Belgium to France, negative values represent an export from France to Belgium. As mentioned before, the cyclical increase/decrease and the directional switch as from March 2011 can be clearly observed below.

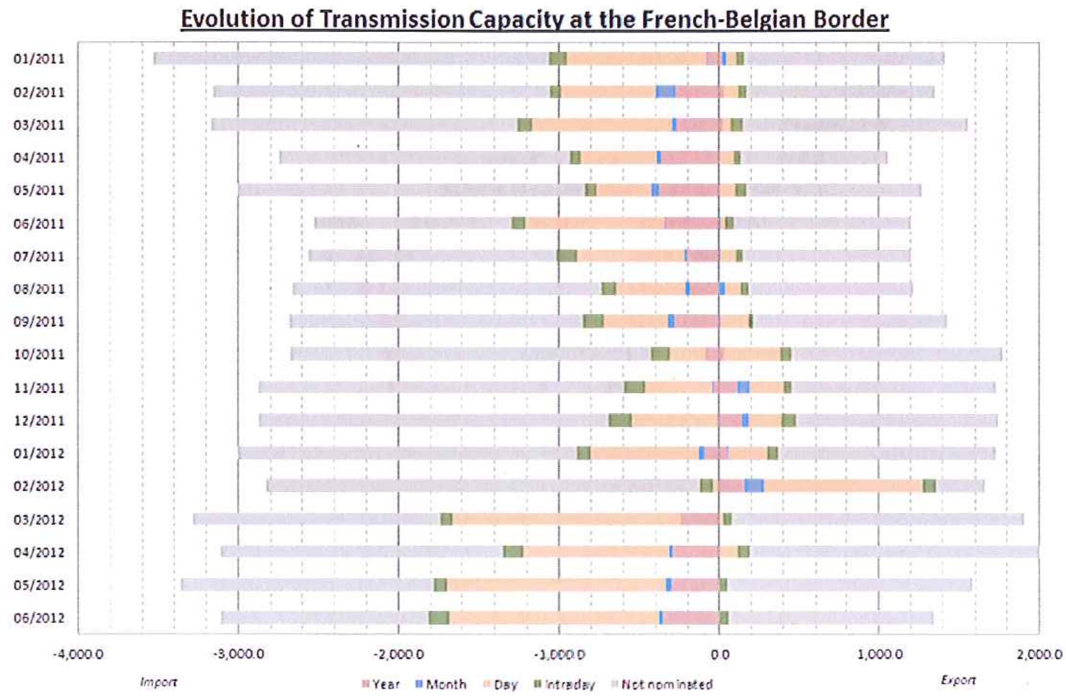

Figure 7: Evolution of Transmission Capacity at the French-Belgian Border (MW)

From 2011 onwards, Belgium is mainly importing from France except for February 2012, for the reasons already commented (European Cold Wave). In Figure 8 and Table 4 (below), the availability of nuclear power plants in France is shown. The France to Belgium import tends to increase when there is a large availability of nuclear power plants in France and decreases when the availability of French nuclear power plants decreases. However, during May and June 2012, the availability of French nuclear reactors is 10% lower with respect to the same months in 2011 and, still, imports in Belgium increased during these months (to around 1800 MW). This later is driven by a combination of good French hydro reserve and the switch between Clean Spark Spread and Clean Dark Spread. Coal generation rose more than 200% in France between July 2011 and July 2012 (most CCGTs were not running in the country), plus an increased excess demand with respect to local generation sources in the North (since Belgium was also exporting around 1200 MW to the Netherlands simultaneously, which may mean part of it was also energy in transit from France). In particular in the Netherlands, high gas spot prices have had an impact on the market, fostering imports in the area from all the cheaper CWE zones, some of which (like France) need to transit Belgium.

In 2009 and prior to June 2010 the market had seen large export flows from Belgium to France. In 2011, the French demand lowering, combined with the decision on the nuclear moratorium in Germany (on March 15th 2011) had resulted in stronger export flows from France to Germany (via Belgium). This led to the reversion in the Belgian export trend towards France, which we still observe today through the persistence of Belgian imports (even with a lower nuclear availability in France). This is due to different market drivers that have more to do with decreased local consumption levels in France and Belgium and, overall, high gas prices in the North.

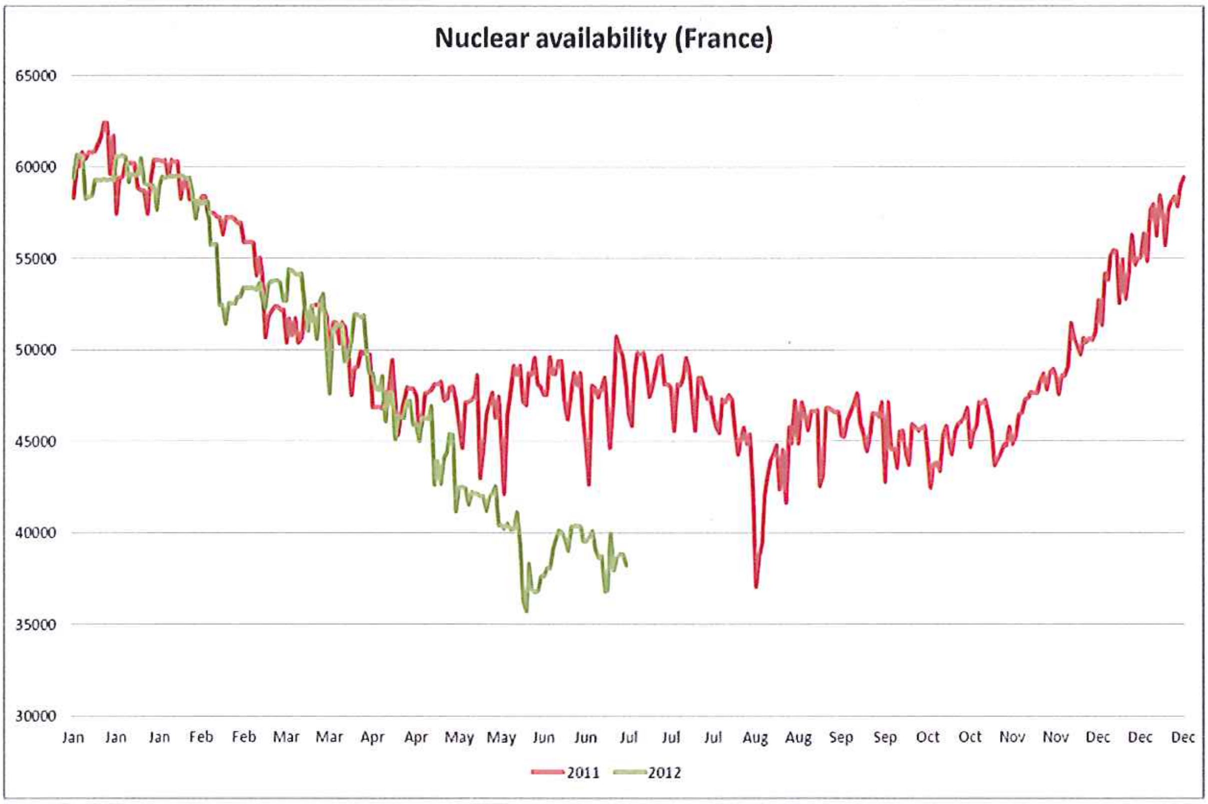

Figure 8: Nuclear Availability in France (MW)

	Avg. Nuclear Availability (MW)		Avg. Nuclear Availability (% Total Installed Nuclear Capacity)	
Date	2011	2012	2011	2012
January	60099	59468	95.00%	94.01%
February	57852	56001	91.45%	88.53%
March	51953	52348	82.13%	82.75%
April	47808	47356	75.57%	74.86%
May	46954	41091	74.22%	64.96%
June	47862	38943	75.66%	61.56%
July	48028		75.92%	
August	44465		70.31%	
September	45720		72.30%	
October	45255		71.57%	
November	47961		75.84%	
December	55470		87.74%	
Total	49916	49193	78.92%	77.76%

Table 4: Nuclear Availability in France, in Absolute and Relative Terms

Figure 9 represents the percentage of congestion on the French-Belgian Border in both directions. During 2011 and 2012, these congestions mainly occur in the direction from France to Belgium (imports). Except for February 2012, when (due to the reasons already exposed) congestion was present mainly in the opposite direction.

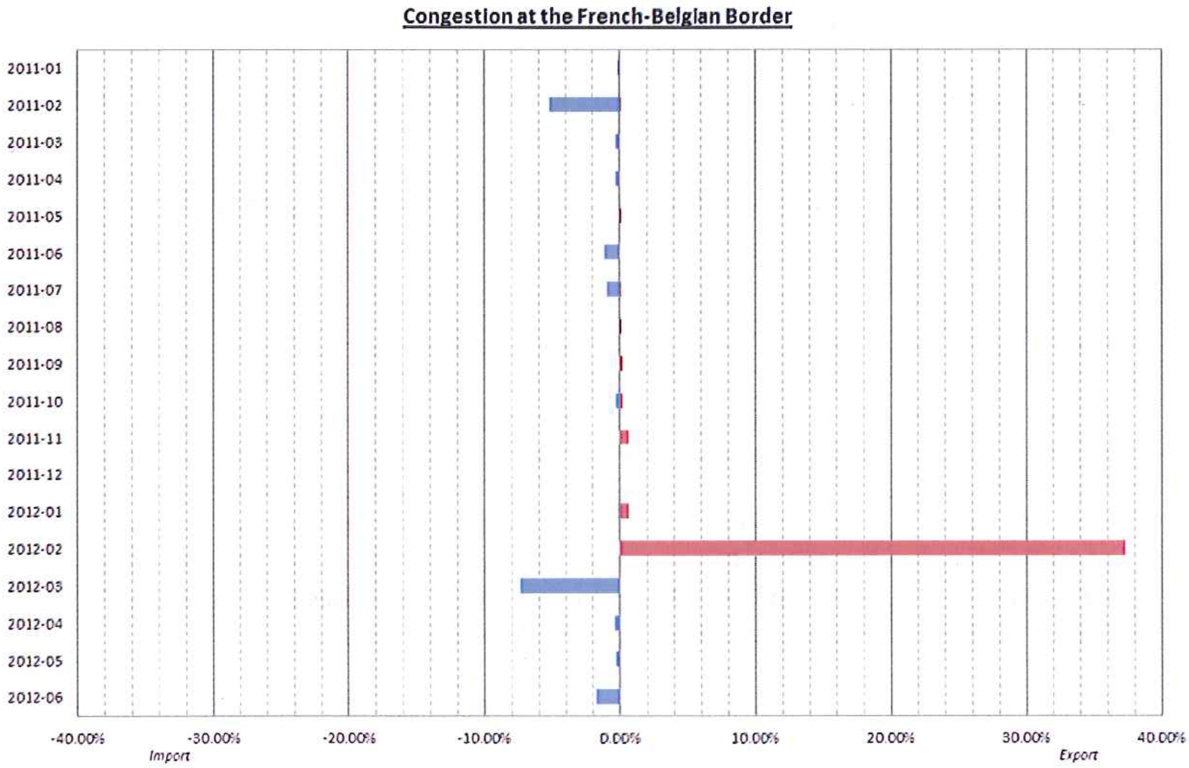

Figure 9: Congestion at the FR-BE Border

From January 2011 till March 2011, Belgium is increasingly importing from France (665 GWh on average) and the Netherlands (489 GWh on average). As from April 2011 and with the announcement of the German nuclear moratorium, Belgium is further increasing its imports from France (756 GWh on average till end of September 2011) and is also exporting to the Netherlands (916 GWh on average). From October 2011 until February 2012, Belgium is exporting to France (512 GWh on average) and importing from the Netherlands (719 GWh on average). Belgium is further importing from the Netherlands until April 2012 (831 GWh on average) and is also importing from France (550 GWh on average). During May and June 2012, Belgium is importing from France (729 GWh on average), but is also exporting to the Netherlands (446 GWh on average), following the seasonal pattern for this latter.

4.2 Offered Capacities

In this Section, we present, for each direction of the interconnection, the evolution of the offered capacity for the monthly and daily allocations and the "origin" of this capacity.

4.2.1 Offered Yearly Capacity

The offered yearly capacity for the yearly auctions (ATCy) in 2012 was:

- 1450 MW in the direction France to Belgium,
- 400 MW in the direction Belgium to France.

4.2.2 Offered Monthly Capacity

For the monthly allocation, the offered capacity is calculated taking into account:

- The part of the NTC value to be proposed at the monthly allocation by application of the Split Rules between monthly and daily allocation,
- The volumes coming from the resale of yearly capacity to the monthly auction;

Figure 10 and Figure 11 show that:

- For both directions there is a cyclical in/decrease (seasonal temperature oscillations)
- Monthly capacity values oscillated between 75 MW and 475 MW for the direction France to Belgium. Between June and October 2011 monthly capacity was under 200 MW due to the fact that during 2011 the previous old set of Split Rules were applicable. The new Split Rules only started in 2012. The previous Split Rules stipulated that 100 MW should be reserved to Monthly Capacity if possible. Otherwise the difference had to be split according to the following rules: 25% to monthly and 75% to daily allocations. This has changed since 2012 (with the introduction of the MAmin of 200 MW for both directions)
- Monthly capacity values oscillated between 200 MW and 550 MW for the direction Belgium to France
- Resale of yearly capacity to the monthly auctions is only frequent for the direction Belgium to France till June 2011 (up to 110 MW) but, ever since then, this has not occurred anymore

- Resales are also present several times for the direction France to Belgium until May 2011 (up to 82 MW) but, since then, they seem to have stopped too.

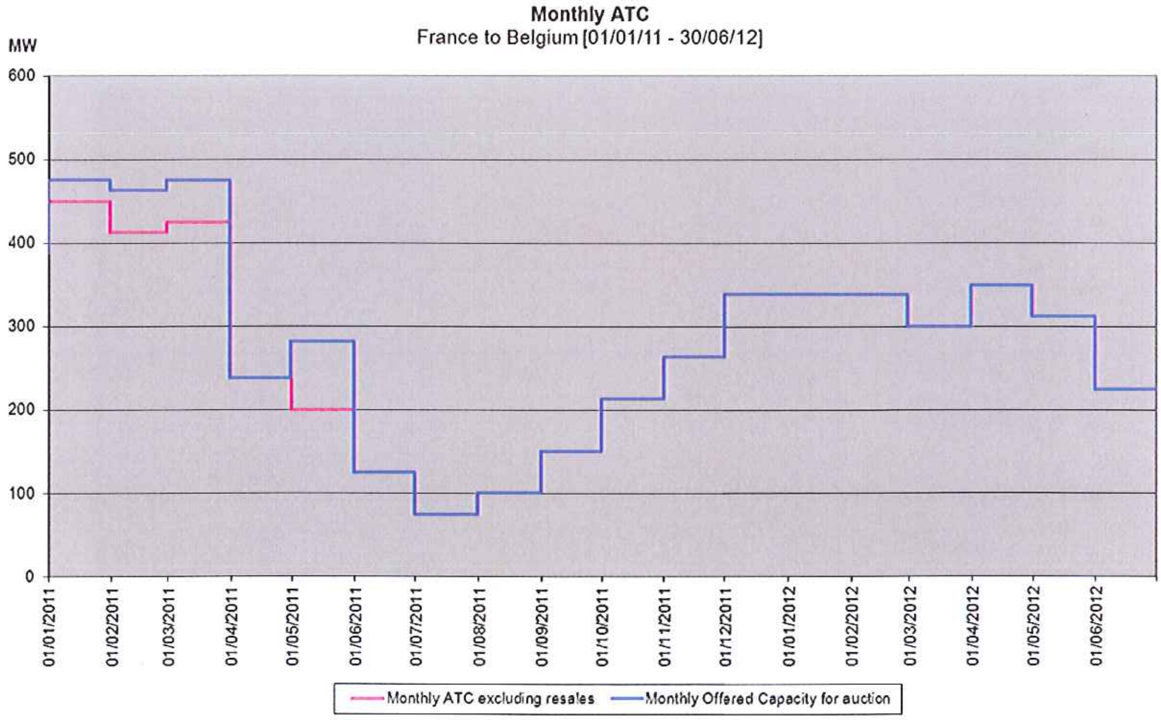

Figure 10: Monthly ATC Offered for Auction, Incl. and Excl. Resales in the Direction Belgium to France

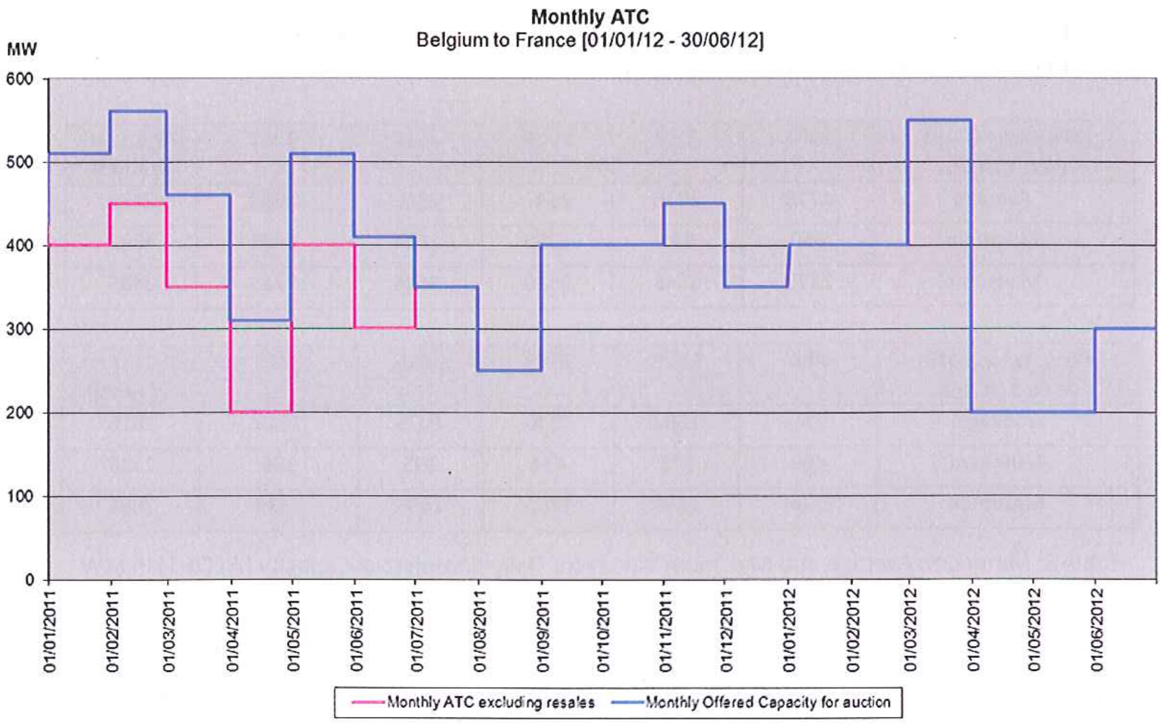

Figure 11: Monthly ATC Offered for Auction, Incl. and Excl. Resales in the Direction Belgium to France

4.2.3 Offered Daily Capacity

The values of daily available capacities (ATCd-1) from January 2011 till end of June 2012 are shown in Figure 12. The minimum off-peaks at the beginning of the period correspond to the extraordinary capacity reduction event experienced during February 4th, 5th 2011 within the whole CWE area.

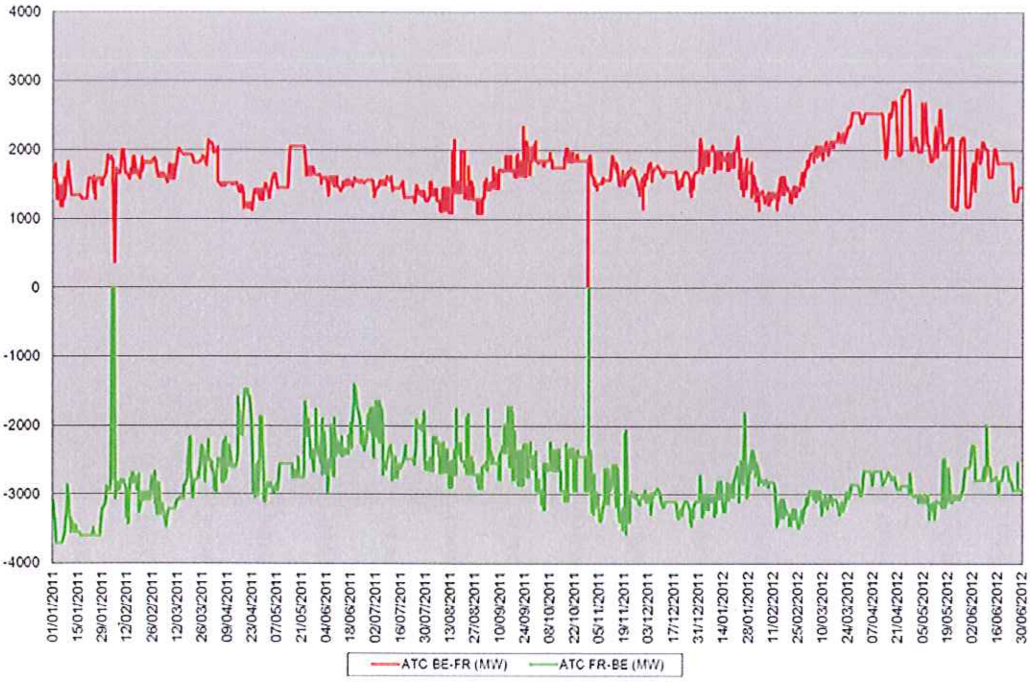

Figure 12: Daily Available Capacity in both Directions at the Belgian-French Border

In Table 5, the minimum, average and maximum values for the daily commercial capacity (ATCd-1) are shown in MW since 2007, for both directions.[6]

Direction FR→BE ATCd-1 in MW	2007	2008	2009	2010	2011	2012 (End of June)
Average	1718	2016	2547	2860	2698	2933
Minimum	650	945	1350	1434	1405	1822
Maximum	3172	3645	3680	3685	3715	3485

Direction BE→FR ATCd-1 in MW	2007	2008	2009	2010	2011	2012 (End of June)
Average	965	1088	1040	1025	1613	1916
Minimum	460	575	434	395	365	1136
Maximum	1500	1730	1760	1456	2333	2881

Table 5: Minimum, Average and Maximum Values for Daily Commercial Capacity (ATCd-1) in MW

The average ATCd-1 is increasing in the direction FR→BE except in 2011. During 2011, high imports coming into Belgium from France induced an increase of the long term nominated share and, hence,

[6] The minimum values do not take into account the values where ATC d-1 = 0 (cfr. February 4th and 5th 2011)

resulted into a reduction of the ATCd-1 in this same direction. This is due to the application of the netting principle for the determination of the ATCd-1. For the same reasons, the opposite is happening in the direction BE→FR with an increase of the ATCd-1 in 2011 (compared to its levels in 2009 and 2010). In 2012 the average ATCd-1 has increased again and is larger than the level of 2010 (and 2011) in the direction FR→BE. But the ATCd-1 has also increased in the direction BE→FR.

The increase in ATCd-1 can be compared with the increase of NTCd-1 in both directions (Table 6). The long term nomination share did not significantly change in 2012 (until June) with respect to its level in 2011 (Table 13). When comparing the average NTCd-1 to the ATCd-1 from 2009 we can perceive the directional switch in nominations that has taken place in 2011 and 2012 (end of June).

Direction FR → BE	2009	2010	2011	2012 (end of June)
Average NTCd-1	2508	2696	2880	3118
Average ATCd-1	2547	2860	2698	2933
Share	101%	106%	94%	94%

Direction BE → FR	2009	2010	2011	2012 (end of June)
Average NTCd-1	1089	1186	1420	1729
Average ATCd-1	1040	1025	1613	1916
Share	95%	86%	116%	111%

Table 6: Average Daily NTCd-1 and Daily Commercial Capacity (ATCd-1)

Figure 13 and Figure 14 show the month and year allocated capacity, the resales from year and month to the daily capacity and the day ahead market spread for both directions.

For the direction France to Belgium, the resale volumes are lower for the period from April 2011 till October 2011 and for the period starting from April 2012. Resale volumes decreased partially also after the February 4th and 5th 2011 events. During three periods, there is a large price spread between Belgium and France. The first large price spread occurs during the events of the 4th and 5th of February 2011. On the 28th of March, there was a full market decoupling. The cold wave during the winter (February) of 2012 also causes some price spreads.

For the direction Belgium to France the resale volumes are rather low except for the period from November 2011 until March 2012. During that period, the nominations increased. There is a large price spread during the cold wave in the winter (February) of 2012.

The periods with price spreads generate uncertainty and market parties react to this atmosphere by increasing their nomination levels. There is also a memory effect involved.

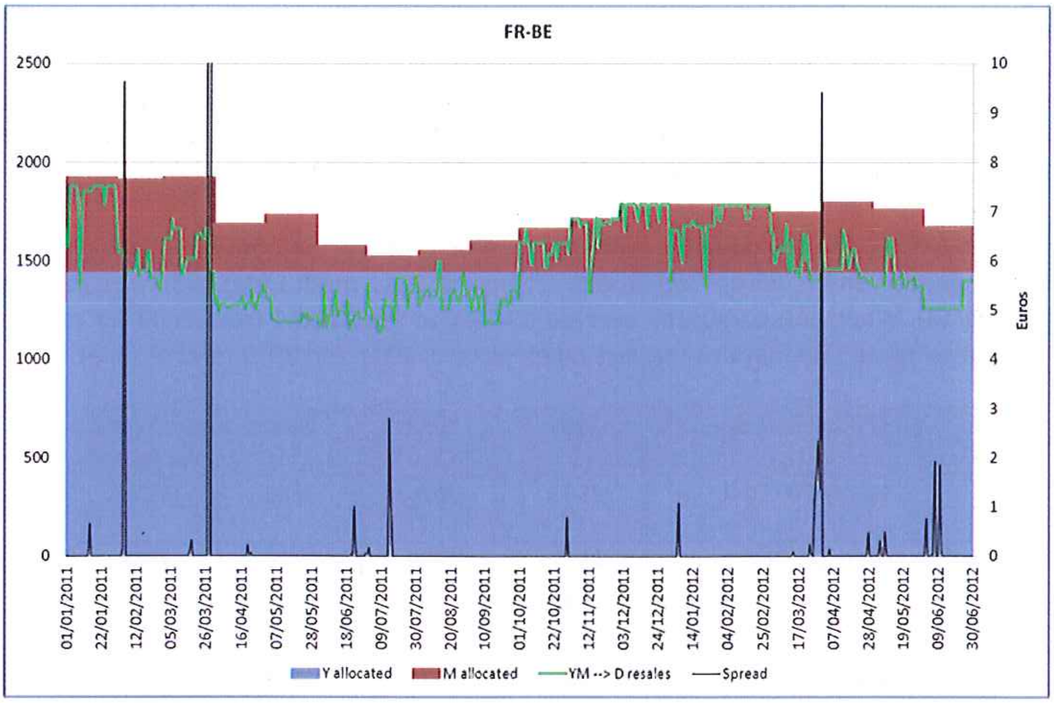

Figure 13: Month Allocated Capacity, Year Allocated Capacity, Resales From Year and Month to Daily Capacity and DA Market Spread in the Direction France to Belgium.

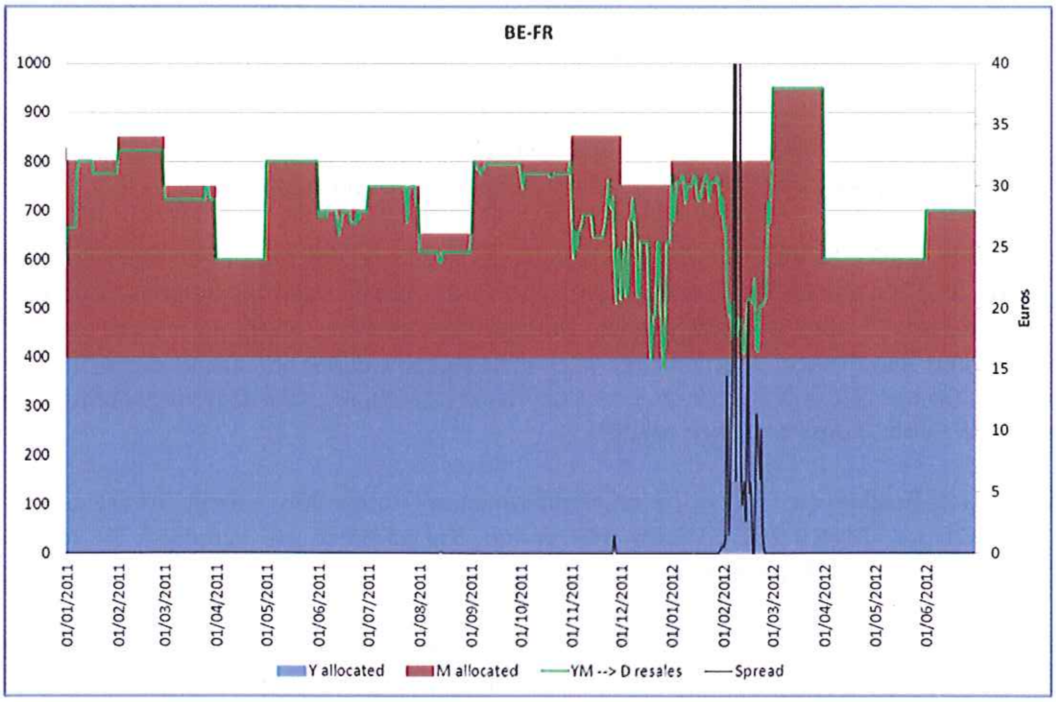

Figure 14: Month Allocated Capacity, Year Allocated Capacity, Resales From Year and Month to Daily Capacity and DA Market Spread in the Direction Belgium to France.

Table 7 displays the average resales volume for year 2009[7] till June 2012 and the percentage of resale volume compared to the amount of allocated capacity.

[7] Please notice the replacement of the UIOLI principle by the UIOSI one in November 2009.

For the direction France to Belgium, until 2012 (end of June) the resales level has remained stable in relative terms with respect to 2011, revealing a quasi-FTR-option use of the PTRs. In absolute terms, resales have very slightly increased from 2011 to 2012 (just 67 MW). With the directional switch as from March 2011, the resale volumes have decreased as more long term nominations occurred demonstrating the PTR use by some Market Parties.

For the direction Belgium to France, the resale volume remains more or less constant, around 72% in 2009 and 2010 till November and increasing to almost 93% in the last period due to the directional switch as from March 2011. 2012 has the same trend, with no significant differences.

	FR→BE		BE→FR	
Year	Average Daily MW Resales	In % Allocated LT Capacity	Average Daily MW Resales	In % Allocated LT Capacity
2009	986	64	467	73
2010 (until 9th of November)	1504	95	475	72
10th of November 2010 until 31 December 2011	1452	87	698	91
2012 (end of June)	1519	86	688	93

Table 7: Absolute And Relative Resale Volume

4.3 Explicit Auctions

4.3.1 Explicit Auction Results

The following Figures show the variation of prices and volumes within the allocation of monthly and yearly capacities for both directions of the French-Belgian interconnection. Data is displayed from January 2011 until June 2012.

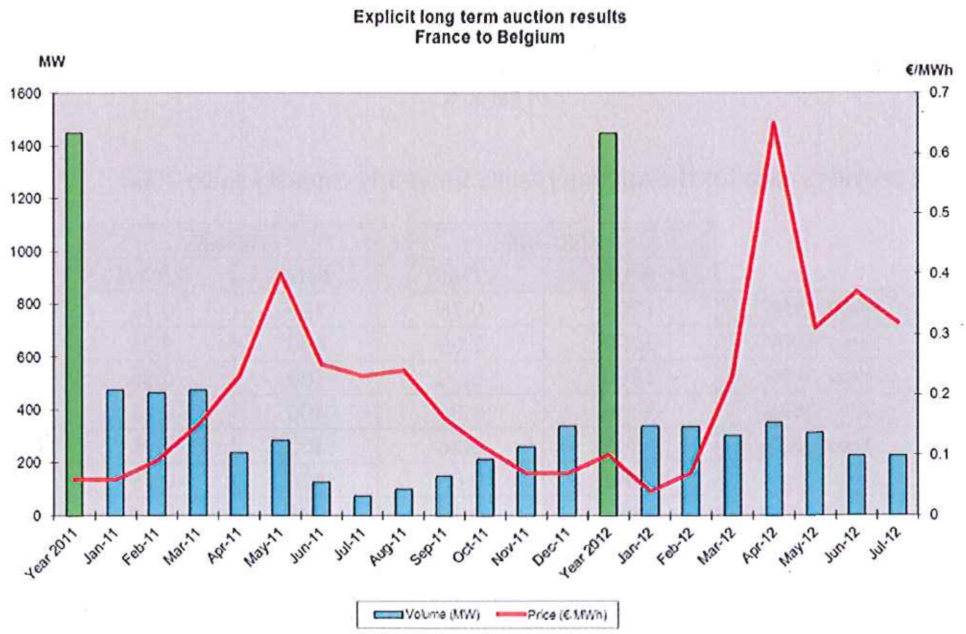

Figure 15: Month Allocated Capacity Volume and Price, Year Allocated Capacity Volume and Price in the Direction Belgium to France

In Figure 15, for the direction France to Belgium and specially during 2011, monthly auction allocated volumes for the winter were higher than those in the summer. Auction prices have increased during summer months of 2011 and 2012. Average auctioned monthly volume in 2011 was 266 MW (0,17 €/MWh) and 298 MW (0,28 €/MWh) in 2012 (end of June). Yearly auction prices seem to have increased slightly in 2012, thereby revealing a more economic appreciation of the market for this direction.

For the direction Belgium to France (Figure 16), The average auctioned monthly volume (price) in 2011 was 412 MW (0,24 €/MWh) and 335MW (0,19€/MWh) in 2012 (end of June). Yearly auction prices have remained more or less at the same level of around 0.15 €/MWh, except for the peak of 0.8 €/MWh registered in the average for December 2011 (probably reflecting the expectations of some market agents for the tightening of price conditions during the winter in this direction).

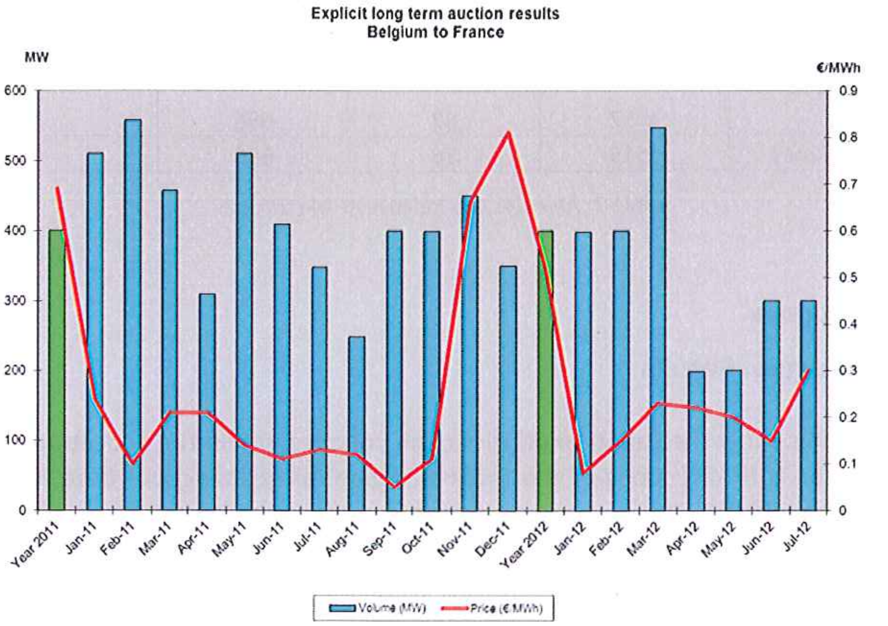

Figure 16: Month Allocated Capacity Volume and Price, Year Allocated Capacity Volume and Price in the Direction France to Belgium

Table 8 (below) provides data for the auction results for yearly capacity since 2006.

	FR→BE		BE→FR	
	MW	€/MW	MW	€/MW
Year 2006	1298	0.76	799	0.11
Year 2007	1299	2.06	400	0.25
Year 2008	1300	0.90	400	0.56
Year 2009	1300	0.88	400	0.81
Year 2010	1300	0.16	400	3.46
Year 2011	1449	0.06	400	0.69
Year 2012	1447	0.10	400	0.52

Table 8: Yearly Auction Results

In general it can be said that, whilst remaining cheap, yearly capacity volumes has increased in the direction France to Belgium between 2011 and 2012. Please notice that, for the direction FR→BE the auctioned volume was 1450 MW in 2011 and 2012, but the allocated amount (the one in Table 8) is sometimes not exactly 1450 MW due to the allocation rules (as described in article 5.01 of the document "Rules for Capacity Allocation by Explicit Auctions v1.0 within CWE, CSE and Switzerland").[8] The opposite direction Belgium to France is more expensive in 2011 and 2012. The price seems to be decreasing and the volume of yearly auctioned capacity remains at 400 MW. It has to be noticed that prices of the yearly auction remain highly dependent on the forward electricity prices on the day that the yearly auction takes place. This explains the few spikes detected in the previous Table (like the 2.06 €/MW for FR→BE in 2007 and the 3.46 €/MW for BE→FR in 2010).

Table 9 summarizes the average volume and price for the monthly capacities.

	FR→BE		BE→FR	
	MW	€/MW	MW	€/MW
Year 2006	667	4.29	152	0.17
Year 2007	253	1.86	227	0.38
Year 2008	167	1.64	179	0.57
Year 2009	215	0.22	245	3.65
Year 2010	292	0.16	290	1.72
Year 2011	266	0.17	412	0.24
2012 (end of June)	298	0.28	335	0.19

Table 9: Average Month Capacity Auction Results

When comparing averages for 2011 and 2012 (end of June) in Table 9, it has to be considered that the first one is a full year and 2012 is only half a year. Additionally, as shown in Table 10, monthly capacity prices in the direction France to Belgium tend to peak around spring-summer, whilst for the opposite direction this tends to happen during the winter period, coinciding with the higher seasonal demand typically registered during these months. There is also an additional drag effect of the levels of the forward prices at the time monthly auctions take place.

Table 10 displays the monthly auction prices and volumes for 2010 and 2011:

	2010				2011				2012			
	FR→BE		BE→FR		FR→BE		BE→FR		FR→BE		BE→FR	
	MW	€/MW	MW	€/MW	MW	€/MW	MW	€/MW	MW	€/MW	MW	€/MW
Jan	498	0.06	250	7.12	474	0.06	510	0.24	337	0.04	398	0.08
Feb	424	0.11	400	2.88	463	0.09	557	0.10	336	0.07	400	0.15
Mar	349	0.10	300	2.10	475	0.15	457	0.21	300	0.23	547	0.23
Apr	274	0.09	200	1.26	237	0.23	309	0.21	350	0.65	199	0.22
May	225	0.18	200	0.45	282	0.40	510	0.14	312	0.31	200	0.20
Jun	150	0.25	200	0.45	125	0.25	409	0.11	225	0.37	300	0.15
Jul	199	0.27	200	0.36	74	0.23	348	0.13				
Aug	125	0.50	200	0.17	100	0.24	249	0.12				
Sep	224	0.18	300	0.27	149	0.16	400	0.05				
Oct	325	0.10	350	1.16	213	0.11	399	0.11				
Nov	325	0.06	449	2.50	260	0.07	450	0.66				
Dec	386	0.03	425	1.87	337	0.07	350	0.81				

Table 10: Monthly Capacity Auction Results for 2010, 2011 and 2012 (end of June)

[8] *Pro rata* allocation of same price bids and rounding. The full document can be downloaded at the following link: http://www.elia.be/~/media/files/elia/products-and-services/crossborder2/rulesforcapacityallocationbyexplicitauctions_v10_cwe_cseandswitzerland.pdf

From April till August 2011 there has been an increase in the price for the monthly capacities in the direction from France to Belgium. The same trend can be observed in 2012 (till June). In November and December 2012, prices have increased for the monthly capacity in the direction from Belgium to France.

Finally, we look at the relationship between the long term nominations and the price of the monthly auctions. Figure 17 and Figure 18 display the day ahead market spread, the year and monthly nominations and the price of the monthly auctions for both directions at the French-Belgian Border. In the direction France to Belgium, an increase in the prices for the month capacities usually goes together with an increase in the year and month nominations.

For the direction Belgium to France, during the period from November 2011 until December 2011, the monthly auction prices increased together with monthly nominations. However, this trend is not observed during February 2012.

From Figure 17 we can derive a possible positive correlation between the monthly auction price and the month nominations.

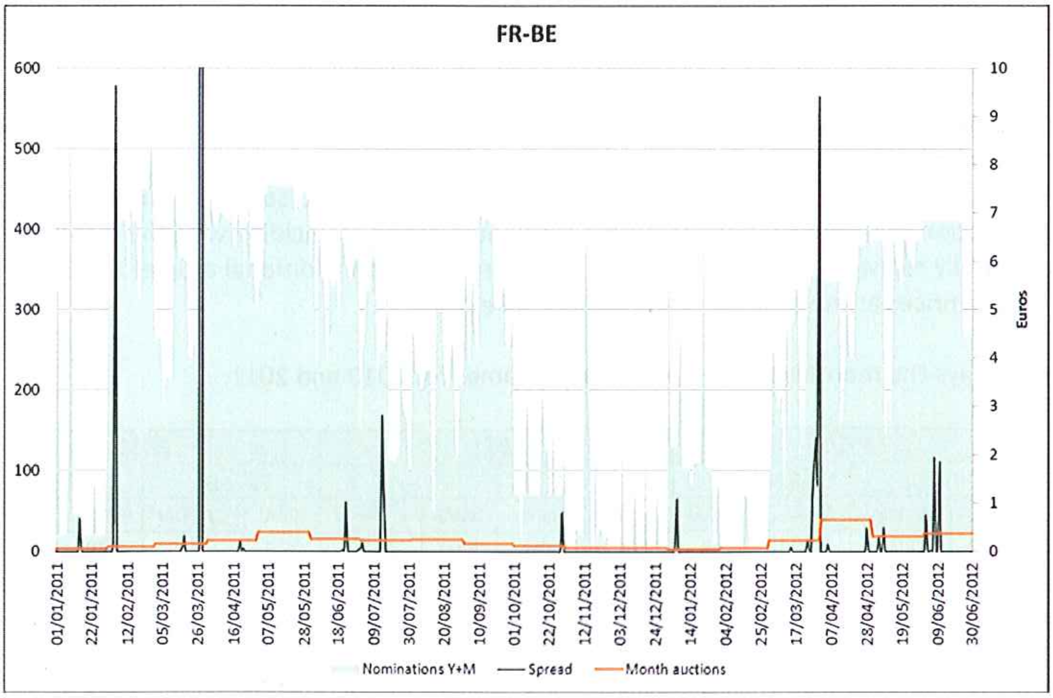

Figure 17: Day Ahead Market Spread, Year and Month Nominations and the Price of the Month Auction for the Direction France to Belgium

From Figure 18, this is less clear due to the fact that in February 2011 the monthly nominations increase without a very significant change in the monthly auction prices.

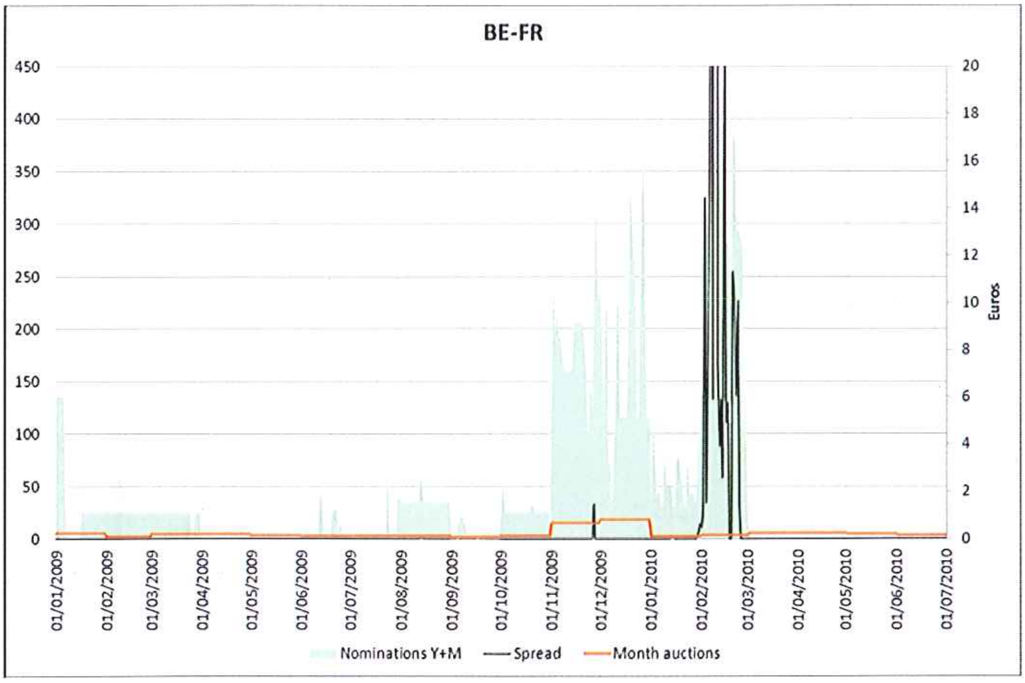

Figure 18: Day Ahead Market Spread, Year and Month Nominations and the Price of the Month Auction for the Direction France to Belgium

It can be inferred, however, that day-ahead market spreads cause uncertainty for market parties, this perception incorporates a memory effect and it usually gets translated into both higher prices in monthly capacity auctions and (with some delay) more long term nominations.

4.3.2 Use of Yearly and Monthly Capacities

First we will focus on the year and monthly nominations. Figure 19 and Figure 20 show the year and monthly nominations and the day-ahead market spread for, respectively, the direction France to Belgium and the direction Belgium to France.

As it can be deducted from both Figures for the period from January 2011 until June 2012, the congestion (and resulting spreads) remains being mainly in the direction France to Belgium (cf. Figure 9). There is less congestion in the other direction except for February 2012 (as an effect of the European Cold Wave and the high consumptions registered during that period in France, coupled with lower than usual nuclear availability).

For the direction France to Belgium, there are usually yearly and monthly nominations when there is also a positive spread. While sometimes the nomination behavior of the market parties follows with some delay a day ahead market spread (January and April 2011), in other periods (August 2011 till October 2011) the majority of the nominations occur in absence of a market spread. This is due to the market expectations of market parties, or in general to their commercial strategy in terms of risk management.

For the direction Belgium to France, for the period January 2011 until January 2012, the market parties have nominated capacity for a rather large amount, but there has been no (significant) day ahead market spread in that direction. In February 2012, the nomination behaviour of the market parties follows the day-ahead market spread.

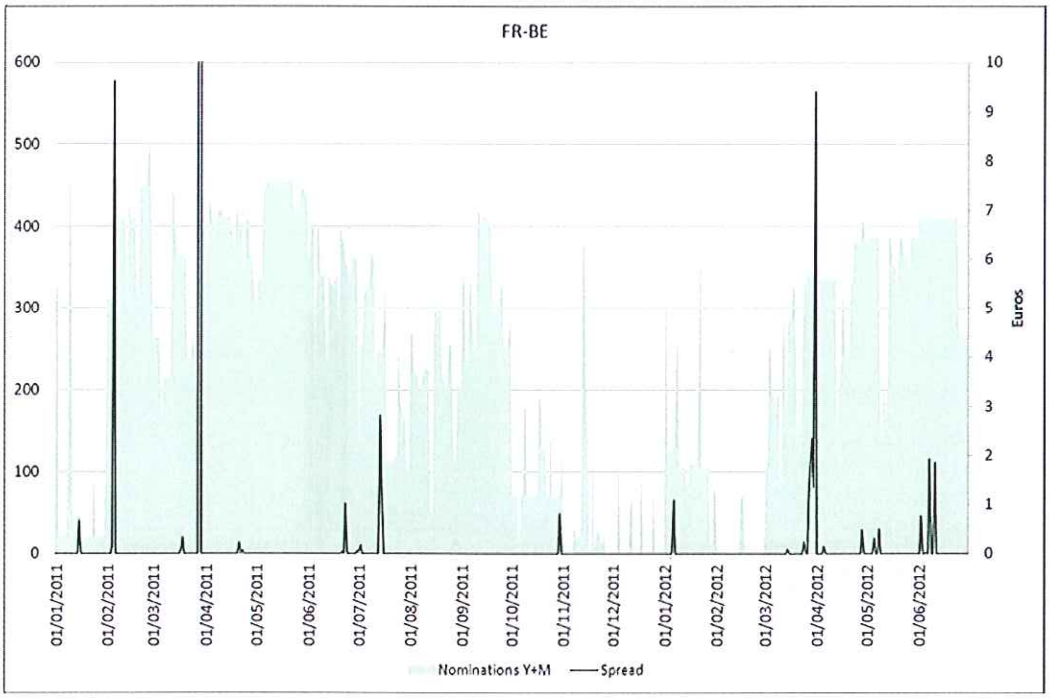

Figure 19: DA Market Spread and Year and Monthly Nominations in the Direction France to Belgium

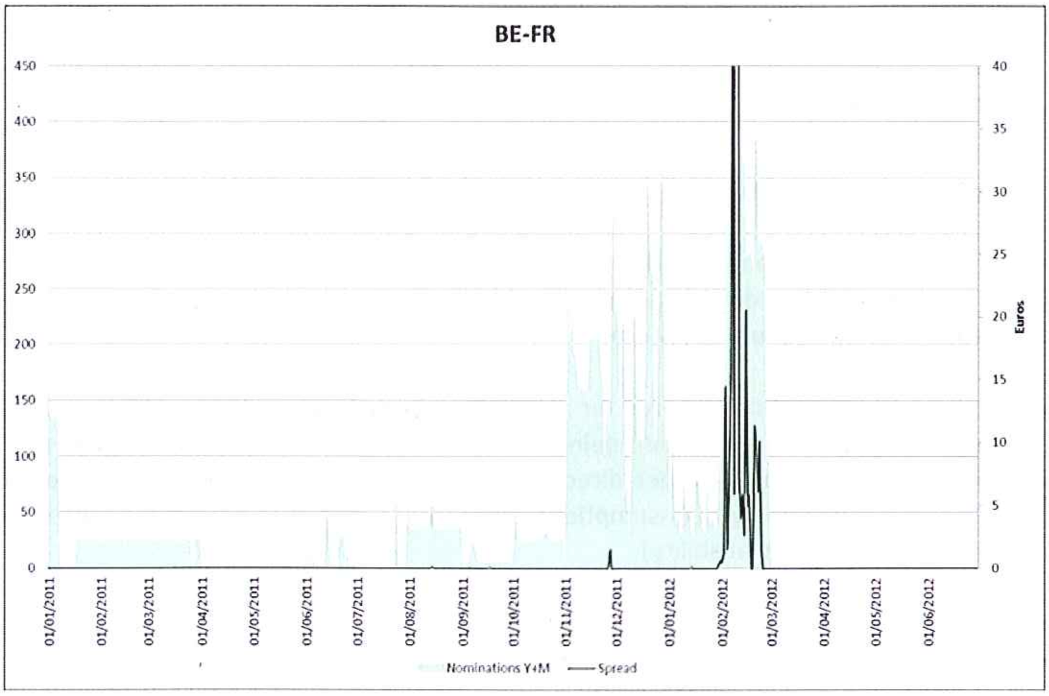

Figure 20: DA Market Spread and Year and Monthly Nominations in the Direction Belgium to France

Table 11 and Table 12 provide an overview of the nominations in both directions. We will define "economic nominations" as those in the direction of the spread, "non-economic nominations" will be nominations against the direction of the spread and neutral nominations will be those made when there was price convergence between France and Belgium. An overall social welfare loss can be associated with non-economic nominations.

For the last period (since CWE Market Coupling) and in both directions, non-economic nominations do seldom occur when nominations are performed (< 1%). Hence the welfare loss is almost negligible (9.5 K€ in 2011 and 3.3 K€ in 2012 by the end of June).

However, in 2009 non-economic nominations did occur quite often in the direction France to Belgium resulting in a welfare loss of more than 384 K€. This does not occur anymore since the launch of CWE Market Coupling.

	Economic Nominations [%]	Non – Economic Nominations [%]	Neutral Nominations [%]	Welfare Loss Due to Non-Economic Nominations [€]	Share of Nominations Compared to Total Hours [%]
2009	0.55	15.09	84.36	-384366	52
2010 (until Nov. 10th)	0.08	9.10	90.81	-38299	63
Nov. 10th 2010 until Dec. 31st 2011	0.73	0.07	99.19	-9530	82
2012 (end of June)	1.25	0.78	97.96	-33647	82

Table 11: Overview of the Nominations in the Direction France to Belgium

Please notice that the increase in welfare loss experienced in 2012 (end of June) is connected to the Cold Wave price spikes impact. Without the month of February 2012, the total welfare loss for 2012 (end of June) would have been of just 171 €, this is much lower than half of the amount registered during the previous period.

	Economic Nominations [%]	Non – Economic Nominations [%]	Neutral Nominations [%]	Welfare Loss Due to Non-Economic Nominations [€]	Share of Nominations Compared to Total Hours [%]
2009	29.66	0.31	70.03	-16236	100
2010 (until Nov. 10th)	15.15	0.05	84.94	-1425	99
Nov. 10th 2010 until Dec. 31st 2011	0.56	0.70	98.74	-103095	72
2012 (end of June)	2.03	0.00	97.97	-1431	33

Table 12: Overview of the Nominations in the Direction Belgium to France

In the direction France to Belgium, nominations have been made for 52% and 82% of the hours (depending on the year), whereas in the opposite direction close to every hour, some nominations were performed for the period 2009-2010. In 2011 and 2012, for this latter direction, the trend has changed and the share of presence of nominations compared to the total available hourly timestamps has decreased significantly to just 33%.

In Table 13, the average hourly nominated capacities and the ratio towards the respective average hourly allocated capacities are presented. The averages have been calculated only for those hours where nominations actually occurred.

	FR→ BE		BE → FR	
	Average Nominated Capacity [MW]	Average Ratio of Nominated Capacity to Allocated Capacity [%]	Average Nominated Capacity [MW]	Average Ratio of Nominated Capacity to Allocated Capacity [%]
2009	103	7.17	150	23.07
2010 (until Nov. 10th)	39	2.62	190	28.09
Nov. 10th 2010 until Dec. 31st 2011	210	12.35	69	8.52
2012 (end of June)	239	13.68	54	6.71

Table 13: Overview of Nominated Capacity

The capacity in the direction France to Belgium is relatively less used (3-14% of allocated capacity) compared to the direction Belgium to France (7-28% of allocated capacity). The latter was the main economic direction from April 2009 until February 2011 but had also less available capacity for allocation. Belgium to France was not the main economic direction for the period 2011-2012.

In 2010 (until November 2010), on average 190 MW were nominated during 99% of the time for the direction Belgium to France. As from March 2011, the economic direction was France to Belgium resulting in higher nomination ratios compared to 2010 for the direction France to Belgium, which can be appreciated in Table 13.

Figure 21 and Figure 22 display the split share of the nominations between yearly and monthly ones, plus the day-ahead market spread, for both directions. For both directions, when they nominate, market parties nominate both month and year capacity.

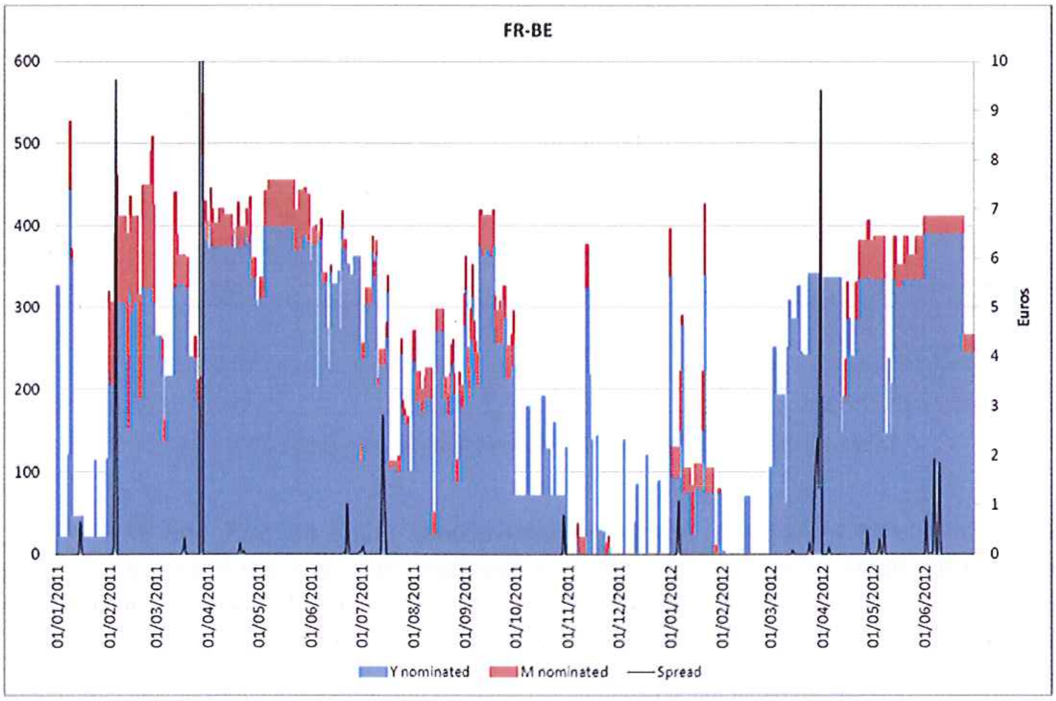

Figure 21: DA Market Spread, Month Nominations and Year Nominations for the Direction France to Belgium

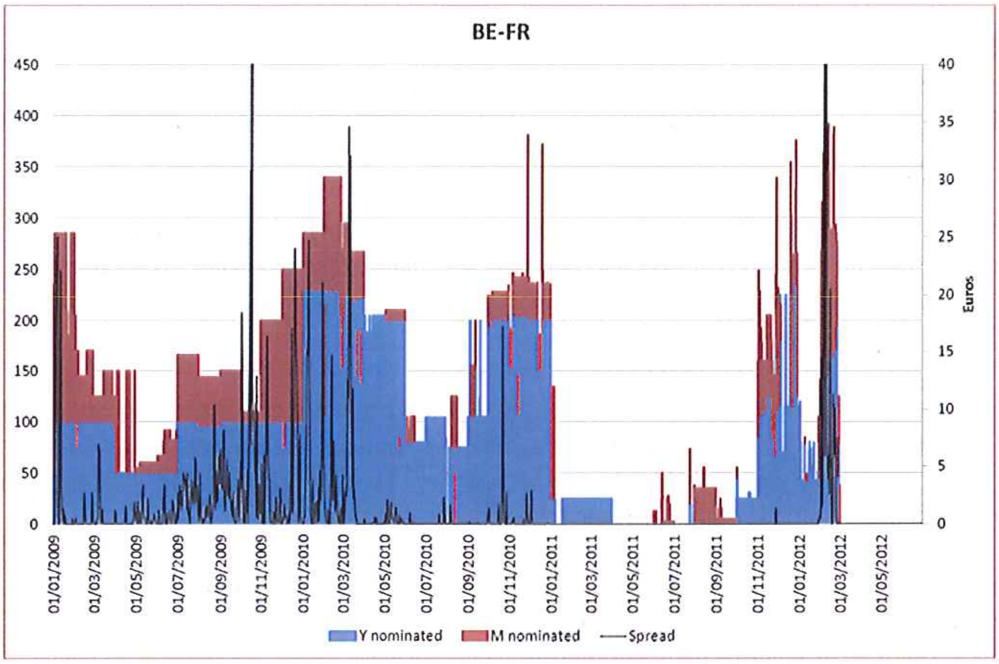

Figure 22: DA Market Spread, Month Nominations and Year Nominations for the Direction Belgium to France.

Table 14 and Table 15 present the average year and month nominations and the ratio with respect to the respective average year and month allocated capacity.

FR→BE *Averages have been calculated for all hours of the year (with nominations and without)*	Average Month Nominated Capacity [MW]	Average Year Nominated Capacity [MW]	Average Ratio of Month Nominated Capacity to Month Allocated Capacity [%]	Average Ratio of Year Nominated Capacity to Year Allocated Capacity [%]
2009	2	101	1.60	7.75
2010 (until 10th of November)	0	39	0.20	2.95
10th of November 2010 until 31st of December 2011	23	187	10.21	2.04
2012 (end of June)	18	220	5.95	15.23

Table 14: Year and Month Nominations and Ratio Nominations to Allocated Capacity in the Direction France to Belgium

BE→FR *Averages have been calculated for all hours of the year (with nominations and without)*	Average Month Nominated Capacity [MW]	Average Year Nominated Capacity [MW]	Average Ratio of Month Nominated Capacity to Month Allocated Capacity [%]	Average Ratio of Year Nominated Capacity to Year Allocated Capacity [%]
2009	63	87	27.43	21.73
2010 (until 10th of November)	28	162	9.20	40.46
10th of November 2010 until 31st of December 2011	19	50	5.03	12.41
2012 (end of June)	21	33	5.23	8.19

Table 15: Year and Month Nominations and Ratio Nominations to Allocated Capacity in the Direction Belgium to France

In both directions the average year nominated capacity in absolute terms is significantly higher (except for 2009) in the direction Belgium to France (which was then the economic direction). This holds until the direction switch that took place in 2011, as from then, the opposite tends to happen, especially with yearly capacity.

In 2010 (till November 10^{th}) the year nominations in the (mainly economic) direction Belgium to France amounted to 40% of the respective average allocated capacity. The share of month nominations reached 9% in 2010 for the same period. From then on, CWE Market Coupling has reduced these amounts considerably.

However, it can be concluded that some Market Parties still prefer to use their capacity rights, rather than reselling them, even considering that, (apparently) there is no economic rationale to do so. These practices are maybe motivated by some risk policies of market parties and the requirements of their internal portfolio management for their cross border positions.

In the direction France to Belgium, there was almost no month capacity nominated in 2010. In 2011 and 2012, both month and year nominations occur. These values are an indication of which percentage of the allocated capacity is nominated.

In Figure 23 to Figure 26, the relationship between hourly nominated capacity and the respective hourly allocated capacity is shown for both year and month capacity rights in both directions.

From December and more consistently as from February 2011, the ratio increased up to almost 30% of year allocated capacity in the direction France to Belgium.

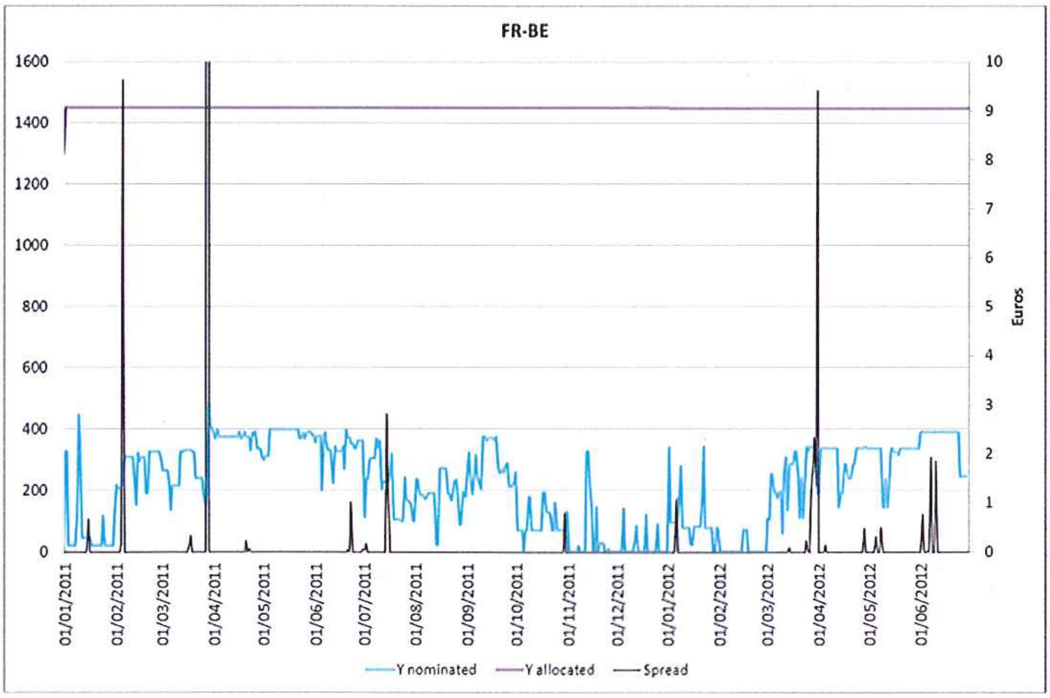

Figure 23: Year Allocated Capacity, Year Nominations and DA Market Spread in the Direction France to Belgium

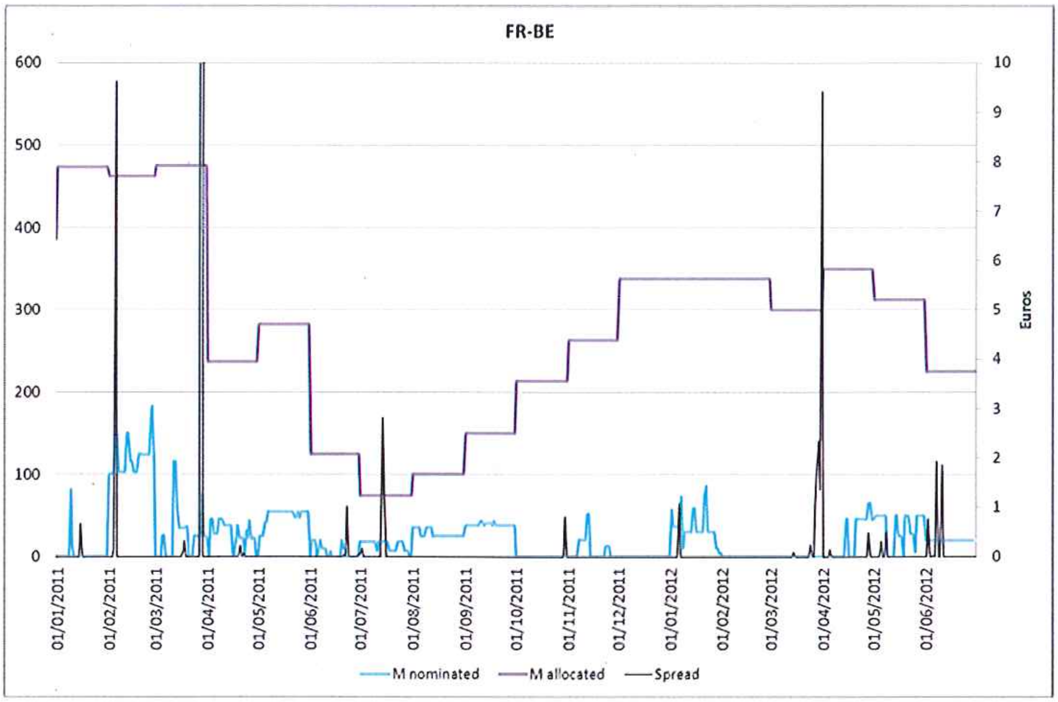

Figure 24: Month Allocated Capacity, Month Nominations and DA Market Spread in the Direction France to Belgium.

In the direction Belgium to France, there are almost no year nominations for the period from April 2011 until October 2011 (excepting some few in the summer) and for the period from March 2012 until June 2012. The same trend can be observed for the month nominations. This lack of nominations corresponds also to periods in which there has been a lack of spread between France and Belgium.

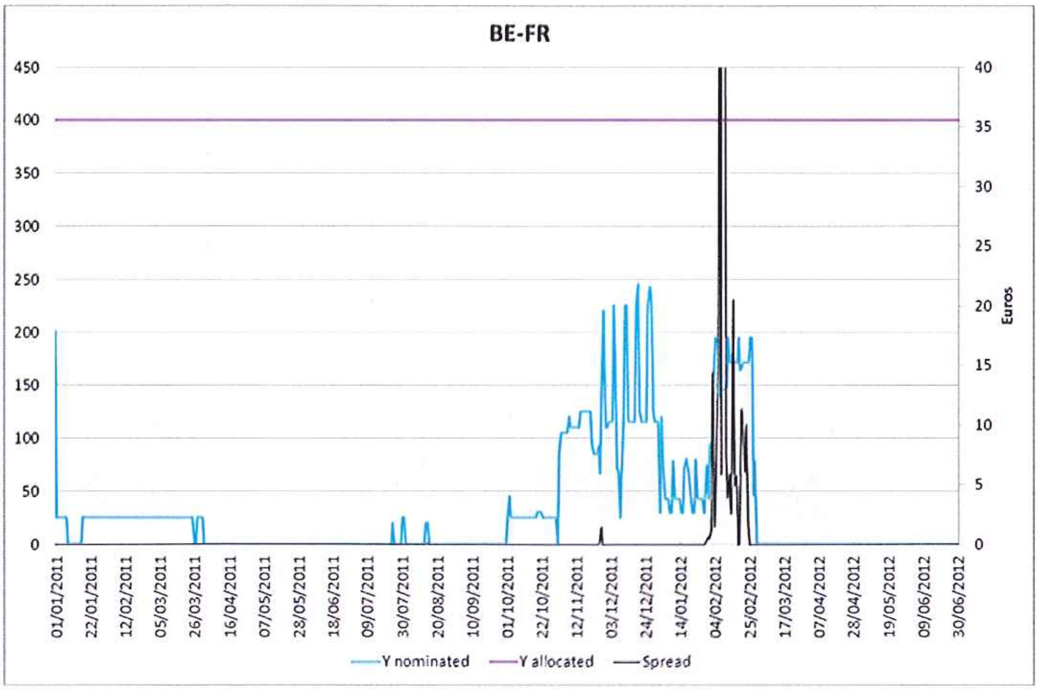

Figure 25: Year Allocated Capacity, Year Nominations and DA Market Spread in the Direction Belgium to France

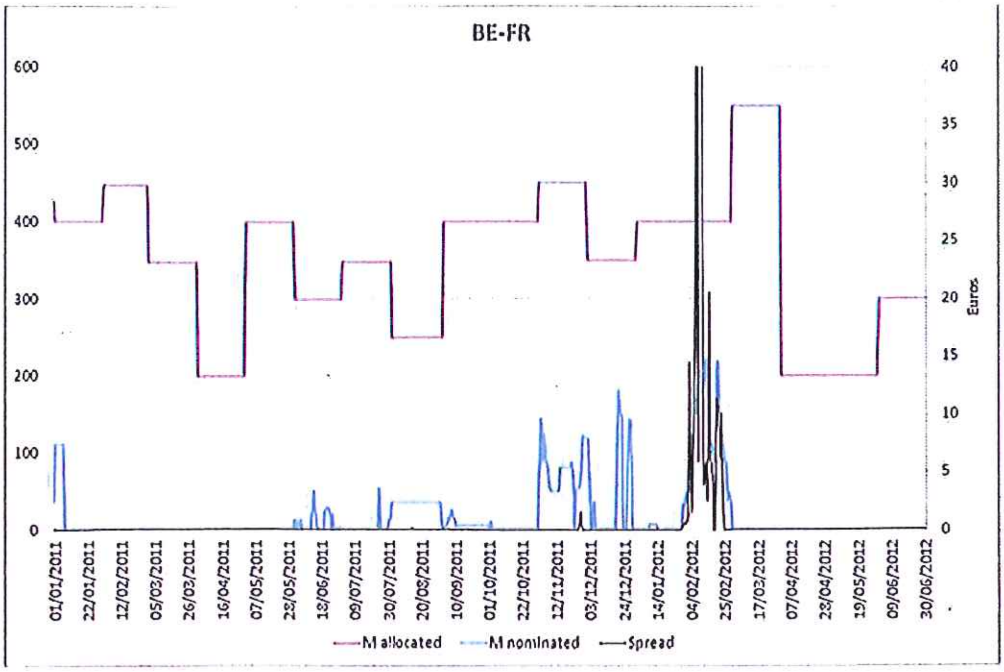

Figure 26: Month Allocated Capacity, Month Nominations and DA Market Spread in the Direction Belgium to France

4.3.3 Market Participants Nominating LT Capacities

4.4 Market Coupling

4.4.1 Market Coupling Results

As for Market Coupling (Figure 29), full CWE price-convergence has been achieved up to over 75% during Q1 2011. From April 2011, due to the nuclear moratorium in Germany, the full convergence has decreased to approximately 65% of the time with mainly Belgium and France being coupled in over 95% of the cases. In June 2011, the full price convergence dropped further to 40% and there is a de facto decoupling between Belgium and France on one side and Germany and the Netherlands on the other side. From July 2011 till November 2011, the full price convergence has increased up to more than 80%. As from December 2011, the full price convergence has decreased, with less than 20% in February 2012, due to the unprecedented conditions introduced by the European Cold Wave. From March 2012, the full price convergence has increased again. The decoupling between Belgium and France has decreased significantly during this period. In general, the price convergence between

France and Belgium was 69.95% in 2009, 86.71% in 2010, 99.18% in 2011 and 92.88% for 2012 (end of June).

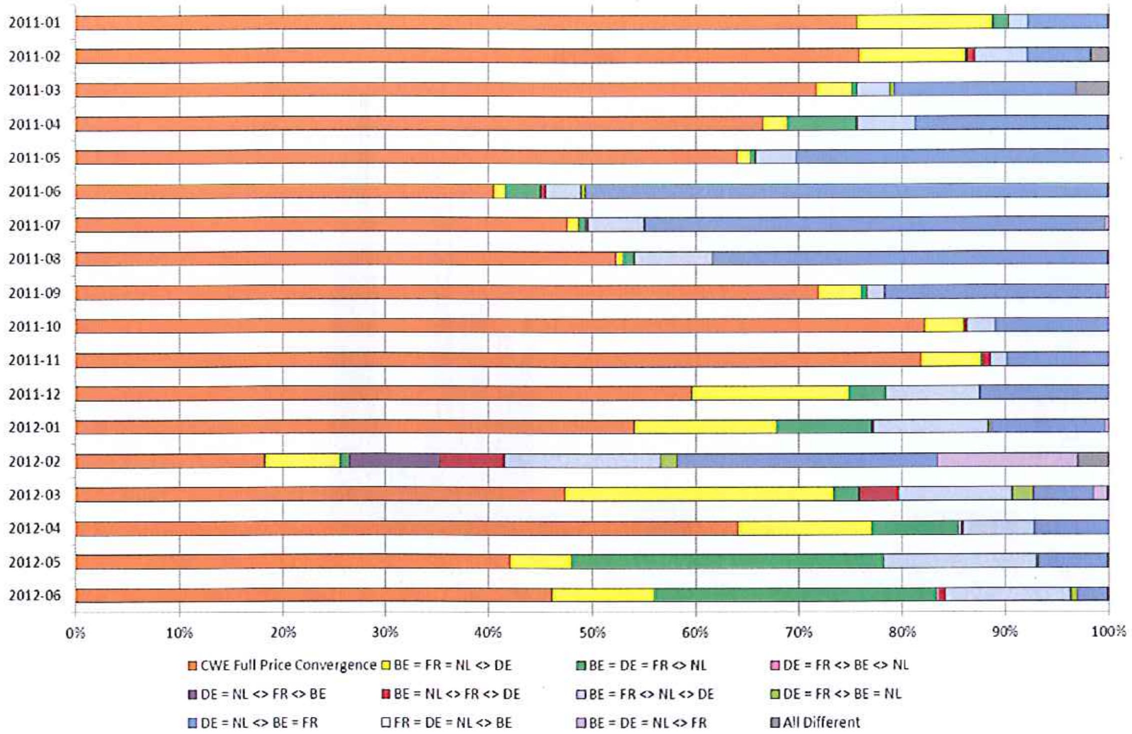

Figure 29 : Price Convergence in the CWE Region

Figure 30 and Figure 31 display the daily average price evolution and price convergence in CWE.

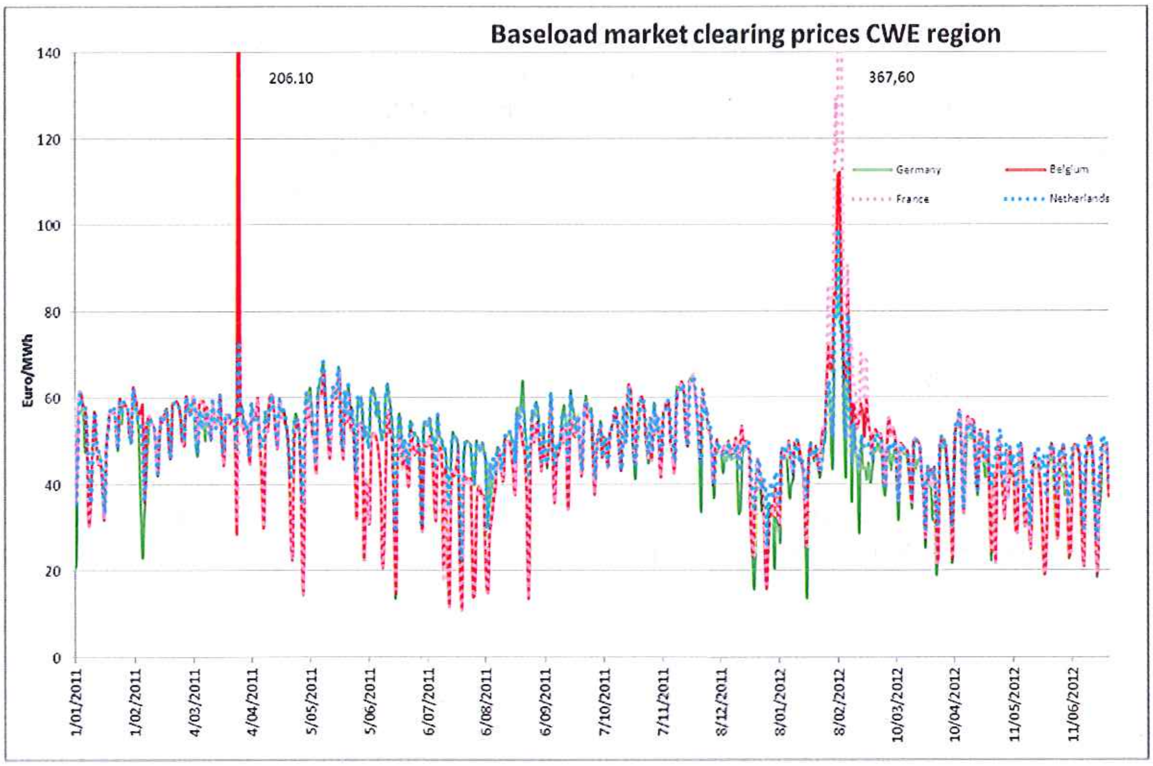

Figure 30: Daily Average Baseload Prices in the CWE Region

The peaks observed in Figure 30 during February 2012 correspond to the Cold Wave. The Belgian peak in March 28th 2011 was due to full decoupling.

There has been a decoupling between Germany and Netherlands (on one side) and Belgium and France (on the other), with the two former presenting the highest prices for the two sets during June and July 2011, this effect was produced by high gas prices in the Netherlands and Germany (and the different effect these have in these countries due to their particular fuel mix) combined with generally low RES outputs in Germany (off-peaking in June 2011 with just 2.5 TWh wind output for the month, which represented the minimum level for 2011).

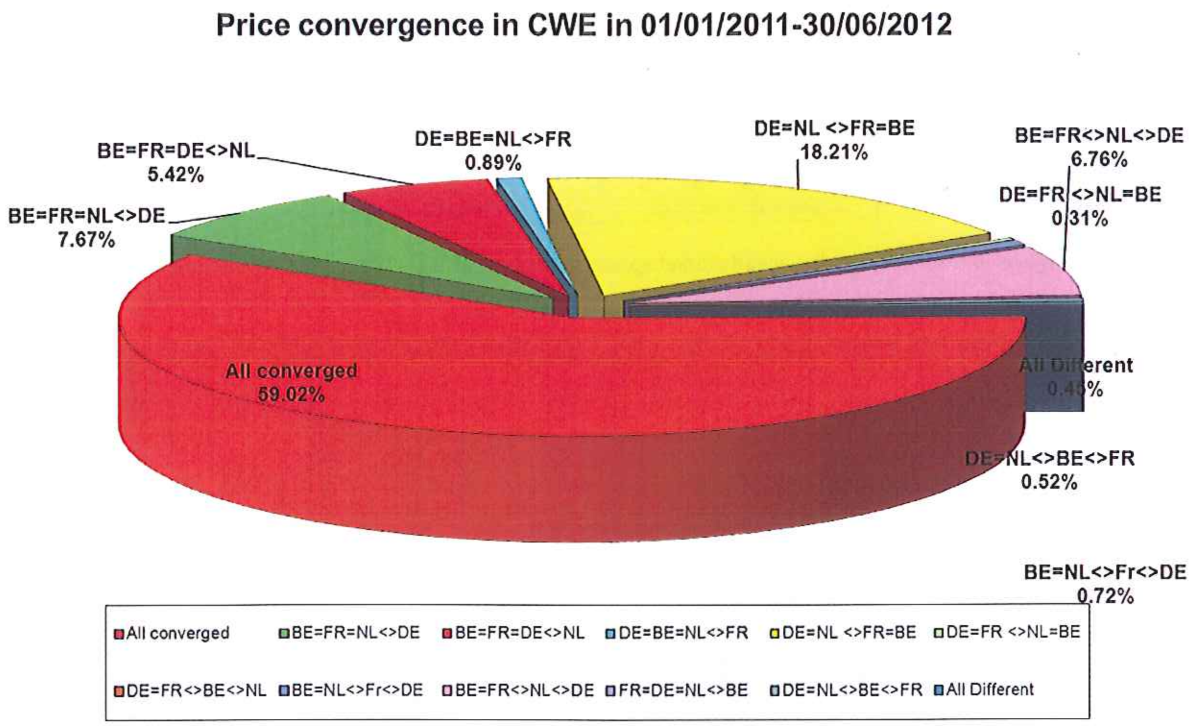

Figure 31: Price Convergence in the CWE Region

4.4.2 Use of Daily Capacities

In Figure 32 we examine the relationship between the available ATC for market coupling in both directions and the day-ahead market spread (negative market spreads indicate a lower price in Belgium than in France).

Lower NTC in summer months has usually the trend to push the ATCd-1 downwards. In the direction BE→FR, the long term nominations placed from November 2011 until March 2012 have resulted into a reduction of the ATCd-1 in this direction. The same occurs in the direction FR→BE as from January 2011. In Figure 33 we depict the DA nominations (used capacity) as well as the ATCd-1 in both directions.

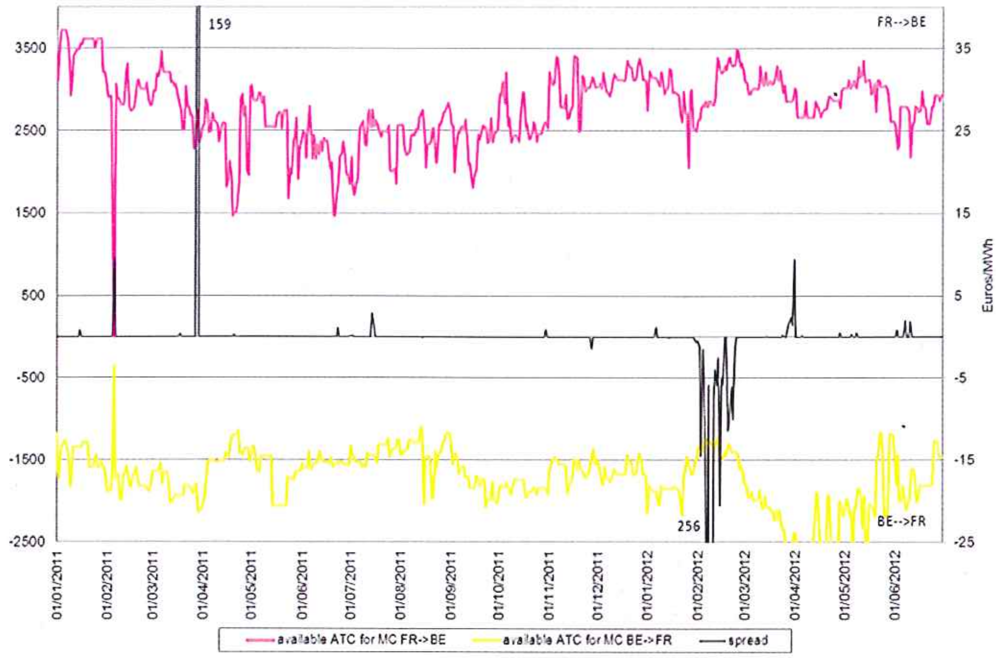

Figure 32: The average day-ahead market spread and the available ATC for MC for both directions

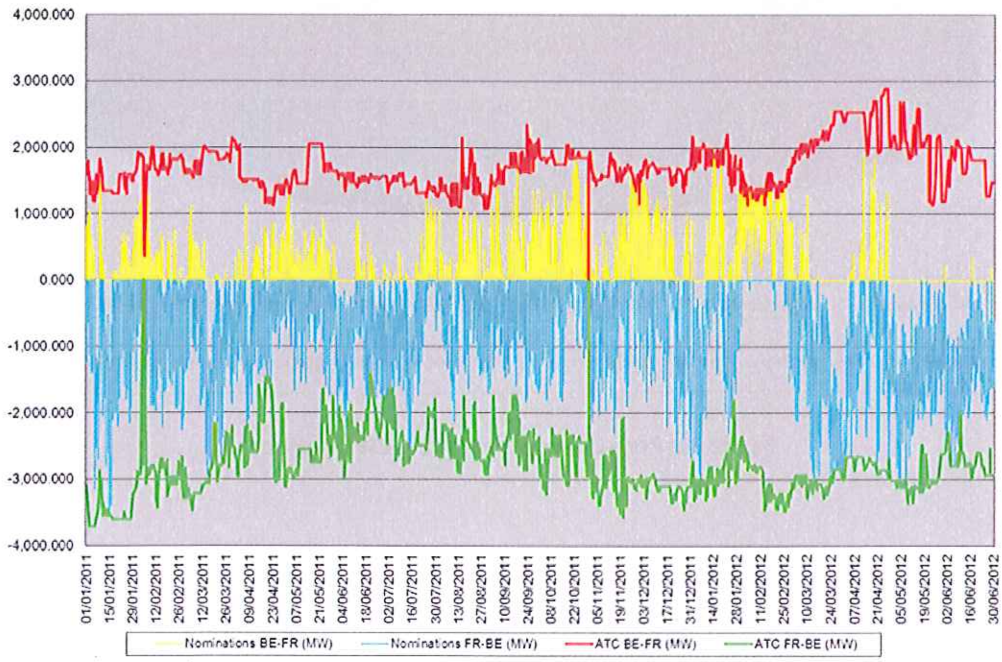

Figure 33: Market Coupling Flows and the Available ATC for Market Coupling in Both Directions.

Figure 33 shows that, generally, the FR→BE direction tends to be tighter than the BE→FR one. The Cold Wave reversed this situation temporarily, provoking congestion in the latter direction.

4.4.3 Market Resilience Indicator BELPEX

Market resilience, or market depth, indicates the price sensitivity due to an increase in offer or demand on the market. Resilience is calculated taking into account the ATCd-1 and the availability of block bids. Because of the importance of this indicator, the analysis recursively runs the fixing on the four CWE bidding zones based on historical order books from BELPEX, APX, EPEX France and EPEX Germany (since CWE Market Coupling from November 10th 2010) for 6 different scenarios:

- An increased offer of 50, 250 or 500 MW at any price for each hour
- An increased demand of 50, 250 or 500 MW at any price for each hour

Table 16 shows the resulting price difference for each scenario on the average base load price, compared to the historical prices on BELPEX, for each year since 2009.

For 2009

P. (€/MWh)	37.41	38.42	39.18	39.36	39.54	40.22	41.19
Delta	-1.95 €	-0.94 €	-0.18 €	0.00 €	0.18 €	0.86 €	1.83 €
Volume	-500 MW	-250 MW	-50 MW	0 MW	50 MW	250 MW	500 MW

For 2010

P. (€/MWh)	44.66	45.48	46.14	46.30	46.46	47.09	47.88
Delta	-1.64 €	-0.82 €	-0.16 €	0.00 €	0.16 €	0.79 €	1.57 €
Volume	-500 MW	-250 MW	-50 MW	0 MW	50 MW	250 MW	500 MW

For 2011

P. (€/MWh)	47.83	48.38	48.82	48.94	49.06	49.52	50.11
Delta	-1.11 €	-0.56 €	-0.11 €	0.00 €	0.12 €	0.58 €	1.17 €
Volume	-500 MW	-250 MW	-50 MW	0 MW	50 MW	250 MW	500 MW

For 2012 (till end of June)

P. (€/MWh)	44.47	45.18	45.75	45.92	46.02	46.81	47.93
Delta	-1.46€	-0.74€	-0.18€	0.00€	0.10€	0.89€	2.01€
Volume	-500 MW	-250 MW	-50 MW	0 MW	50 MW	250 MW	500 MW

Table 16: Price Diff. for each Scenario on the Average Base Load P., Compared to Historical P. on BELPEX

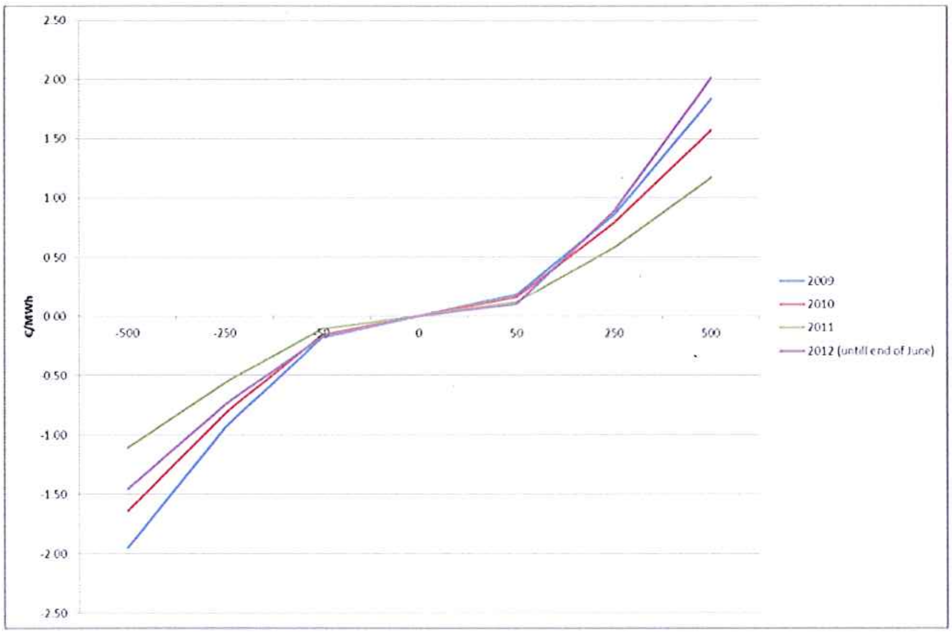

Figure 34: Average BELPEX Market Resilience since 2009

As it can be derived from Table 16 and from Figure 34, the resilience on BELPEX was getting more robust from 2009 to 2011 and, hence, liquidity was improving. For the results available for 2012 (until June), in spite of the presence of the Cold Wave (February 2012) and its associated impact in the order books used for the resilience calculation performed by BELPEX (which uses only the first six months); results seem more or less to be already in line with those from previous years.

Resilience levels of BELPEX, remain at a good overall level, in spite of the previously described effect.

5 Conditions for Implementing Financial Transmission Rights (FTR)

ELIA and RTE are referring to the ENTSOE answer on the draft Framework Guidelines on Capacity Allocation and Congestion Management from June 10th 2011, where the evolution towards FTR is presented as a possible next step after analysis of financial, regulatory and legal implications. Details on such analyses (conducted at CWE level) and on other ongoing initiatives related to FTR are treated in Chapter 6.

A potential evolution towards FTR should be subject to certain market preconditions, necessary to ensure the correct functioning of these products. Namely, these preconditions are:

- The existence of robust and liquid spot market prices at both sides of the border;
- Price market coupling in day-ahead;
- A proven interest of market participants in FTR (via market consultation directly, or suggested indirectly by sustained elevated resale percentages observed *de facto*);
- Revenue adequacy for TSOs should be guaranteed, with full recovery of all costs associated to ensuring payments for FTR holders. This would involve the definition of several risk-related concepts for the new products to be put in place;
- Related to the prior, in the case that the selected products were FTR obligations a clearing house would be needed in order to deal with counterparty risk. Netting policies would then have to be defined in a coordinated manner among TSOs and the clearing house (since these are linked to the risk profiles of these two);
- The clarification of the governance implications of the product, in particular, if a product linked to the physical capacity can be considered or not a mere financial instrument. In relation to this, the impact of financial regulation on FTR and on the entities auctioning and reselling them will also have to be assessed before the implementation of FTR. It is important to mention in this regard that there is still a legislative process in course for the revision and approval of the Markets in Financial Instruments Directive – MIFID. The final content of this directive, which is under review at this moment, may have important implications for entities issuing, auctioning and reselling FTR. Both the current version of MIFID and the one in preparation would need to be assessed in detail so as to discern how these products would be treated under them.

The upcoming Network Code on Forward Markets should detail the possible evolution from PTR with UIOSI towards FTR and the cases in which this would be either applicable or advisable. Moreover the regional approach with respect to the FTR study performed by the TSOs in early 2012 had also been put forward as a deliverable in the draft CWE Work Plan 2011-2014 of ACER, dated June 2011.[9] Section 6 details how all these concerns have been addressed.

For the time being there seems to be clear consensus at ENTSOE, NRAs and at the level of market parties[10] that if FTR are implemented, this should be done in a regionally coordinated way and under the predominant form of FTR options, which present several apparent advantages compared to FTR obligations. These advantages are more detailed in Chapter 6. One of the main ones is simplicity and implementation readiness due to similarity to existing products.

[9] Under Epigraph I.1 for Long Term deliverables. CWE TSOs should produce a study on FTRs implementation, including regulation issues by 2012. This has been done. The Final Version, dated November 2011 contains this request indirectly under Epigraph I.1 as a reference to the follow-up of the ACER Cross-Regional Roadmap for 2014, which includes this very same deliverable as an ENTSOE one for Q1-Q2 2012.

[10] Market Consultation of June 29th 2011 in France and Belgium, conclusions to be reconfirmed or rejected by results from the wider ACER market consultation on long term products (currently being performed and to be finished by end summer 2012).

6 Studies Performed On FTR

As mentioned in Epigraph 59 of CREG Decision (B) 111110-CDC-1123 of November 10th 2011, in its Decision (B) 101125-CDC-1018 of November 25th 2010; CREG had asked ELIA to perform a study about the potential implementation of FTR. This study should cover the proposed volumes, horizons and a recommendation on whether FTR obligations or options should be implemented. Given the fact that this analysis had also been included as a deliverable for CWE TSOs in 2012 within the ACER CWE Working Plan 2011-2014 of June 2011,[11] the study was carried out between January and April 2012. This Chapter elaborates on how CREG demands (in Epigraph 59) have been addressed by the study and other ongoing initiatives.

In fact, at a more general level than CWE, the ACER Cross-Regional Roadmap for Long Term Transmission Rights is based on four sets of actions (all of them to be performed before the European Target Model deadline):

- Harmonization of the auction rules
- Harmonization of the allocation platforms
- Harmonization of the nomination processes
- Possible implementation of FTRs

In order to follow up the development of all these tasks, ACER has constituted a Long Term Task Force in coordination with ENTSOE and all potential stakeholders (through the pertinent consultations). In relation to the last task above ("Possible implementation of FTRs"), the main deliverables for the Task Force were set as:

- EC Study on Long Term Transmission Rights (ACER in coordination with ENTSOE, Q4 2011): assessment of the legal consequences of moving towards FTR, MiFID exemption and potential consequences for allocation platforms if this latter was not to be granted. Several studies have been performed to this respect. Their main conclusion is that FTR issued by TSOs or third parties allocating such FTR on behalf of TSOs should not fall under MiFID. FTR are not the main activity of TSOs, do not generate corporate profit, are linked to a regulated activity and to the physical transmission capacity (in their volume determination). This exemption is probably easier to achieve for FTR options than for obligations due to the closer nature of these former to the current PTR and also to capacity in volume determination (no netting). The regulatory process is still ongoing, though (thereby, please find this item in Chapter 5, mentioned as the last of FTR implementation preconditions)

- Analysis on the possible design and implementation of FTR (ENTSOE in cooperation with ACER and based on the prior deliverable, Q1-Q2 2012): this deliverable is mainly covered for ENTSOE with the Long Term Products Educational Paper[12] (centred into design issues) and for CWE with the study on implementation (more focused on procedures)

- Stakeholders consultation on potential FTR design (ACER, started on August 29th 2012, with completion foreseen on October 28th 2012): the consultation is now wider than just FTR and refers to long term products, market design choices and harmonisation issues in general, it is planned and executed by ACER[13]

[11] And also within ACER Cross Regional Roadmap for Long Term Transmission Rights as an ENTSOE deliverable for Q1-Q2 2012.

[12] ENTSOE Educational Paper on Transmission Risk Hedging Products. This document can be downloaded following the link in Footnote 2.

[13] The documents for this consultation can be downloaded following the link in Footnote 1.

- Elaboration of a pan-European-coordinated implementation planning to move towards FTR (regionally) (ENTSOE and ACER, in close consultation with all involved stakeholders, Q3-Q4 2012): subject to the results of all the previous steps and, therefore, still to be carried out. If necessary, the work on common allocation rules should also be adapted accordingly. As for the general planning and possible timings a very high-level initial blueprint estimation of deadlines has been produced for CWE within the studies described below

During March 2012, under the previously described framework, CWE TSOs launched a study on the implementation aspects of FTR options within the CWE region, including regulatory aspects. The study was focused on FTR options exclusively, following recommendations stemming from a previous study performed at ENTSOE level on FTR products by late 2011 until February 2012.[14] Though this paper contains no ENTSOE position with respect to which long term products should be chosen (this corresponds more to market parties through the ongoing ACER market consultation); the document focuses on design issues and makes it clear that FTR obligations are more complex than FTR options and would be less straightforward to implement, at least as a first step and by 2014. This would be due to the following reasons.

Contrary to FTR options, FTR obligations require the establishment of a clearing house (to prevent counterparty risk). Additionally, they imply the elaboration of coordinated netting policies among TSOs and the clearing house (the risk profile of this latter would be affected by the netting policies of the TSOs). It remains unclear whether market parties would actually purchase capacity against the prevailing market direction (the main trigger for the netting of the obligations), or whether negative prices should be enabled for these auctions (and the potential impact of this). Being the main interest of FTR obligations with respect to options the one that they enable netting (and, thus, the issuing of more capacity rights), but this latter aspect not being yet fully operationally guaranteed in the case of CWE (due to the previous reasons) it was decided to start by focusing provisionally on the introduction of FTR options, whilst waiting for the results from ACER market consultation.

Besides, FTR obligations have many common aspects with FTR options in terms of product characteristics and, additionally, obligations and options can co-exist at the same border if so wished as a market design option (although this is only possible through fundamental algorithm modifications). In the hypothetical case FTR obligations are requested by market parties, these can always be introduced as a second step, or even on top of FTR options.

Therefore, the CWE study started with a workshop on March 1st focused on the operational (procedural) and regulatory impact of the implementation of FTR options. After performing the assessment, the following was agreed among TSOs (these preliminary conclusions were presented to CWE NRAs afterwards). After examining procedural impact changes for TSOs and product characteristics for all parties, FTR seem to have both advantages and disadvantages.
The main advantages of FTRs would be the following ones:

- FTR enable a higher liquidity in the day-ahead market leading to potentially better price formation and more robust market results (since all capacity is sent to the spot)
- Possible competition increase in Transmission Right markets, since the market would become easier to enter (no Balancing Responsible Party contracts needed anymore)
- FTR are fully compliant with the Framework Guidelines for Capacity Allocation and Congestion Management

[14] This study is the ENTSOE Transmission Risk Hedging Products Educational Paper, which is publically available. Please find the download link at Footnote 2 of this document.

- Simplified processes for TSOs since the nomination stage becomes obsolete (saves time for other procedures) and eliminates the need to harmonise nomination procedures (avoiding market parties having to go through the waiting time of this phase)
- Similarity of FTR to current products (PTRs with UIOSI), which would mean extremely limited IT developments and the possibility to keep CASC as auctioning entity

FTR present however the following possible disadvantages:

- No more nominations possible (physical exchanges may still be wished by some market participants, even if under the current CWE market coupling conditions they are becoming more and more irrelevant with respect to the purely financial transactions) – this has triggered the TSO request to hold a consultation with market participants as a pre-requisite for implementation of FTRs
- Related to the prior. Obligation to go through PXs to realise cross border exchanges, with the consequent obligation to pay the associated fees
- Unclear whether MIFID may apply

One conclusion (in reference to CREG Epigraph 59) is that in terms of issued capacity volumes and involved mechanisms, not much would change with FTR options. These have a market functioning that is rather similar to the one of PTRs with UIOSI (with the exception that we would skip all the nomination steps). From a market perspective it has to be mentioned that nomination levels remain low in the CWE area with an average of around 10-15% at most borders. This means that, currently, most PTRs already work financially. It is also relevant to recall that almost all CWE nominations are usually performed either in the neutral market direction (with coupled bidding zones –these are the most with more than 96%), or in the market direction (a much lower proportion) and almost never in the wrong market direction, contrary to the market spread (Table 11 and Table 12 in this document). This adds some evidence for the potential interest of FTR options.

Apart from several technical recommendations and conclusions, the study concretised itself into three possible scenarios for an eventual introduction of FTR options in CWE if these were to be requested by market parties and approved for introduction by NRAs. These scenarios are explained in Figure 35 (next Page).

Scenario 1 and 2 were not possible by design, since they were not compliant with the timings for ACER Market Consultation and CWE Work Plan Roadmap. Additionally, Scenario 2 was also intrinsically unfeasible since it would not have delivered on time for first auctions at the Netherlands border with the new set of rules (Dutch local Law needs to be modified). This places the current status directly under a potential Scenario 3, depending on: feedback from NRAs, opinions from market Parties about FTR during ACER Market Consultation and multiple decisions to be taken on FTR by early October 2012 as the latest, for an implementation in CWE by early 2014 at the earliest (if this implementation is finally requested).

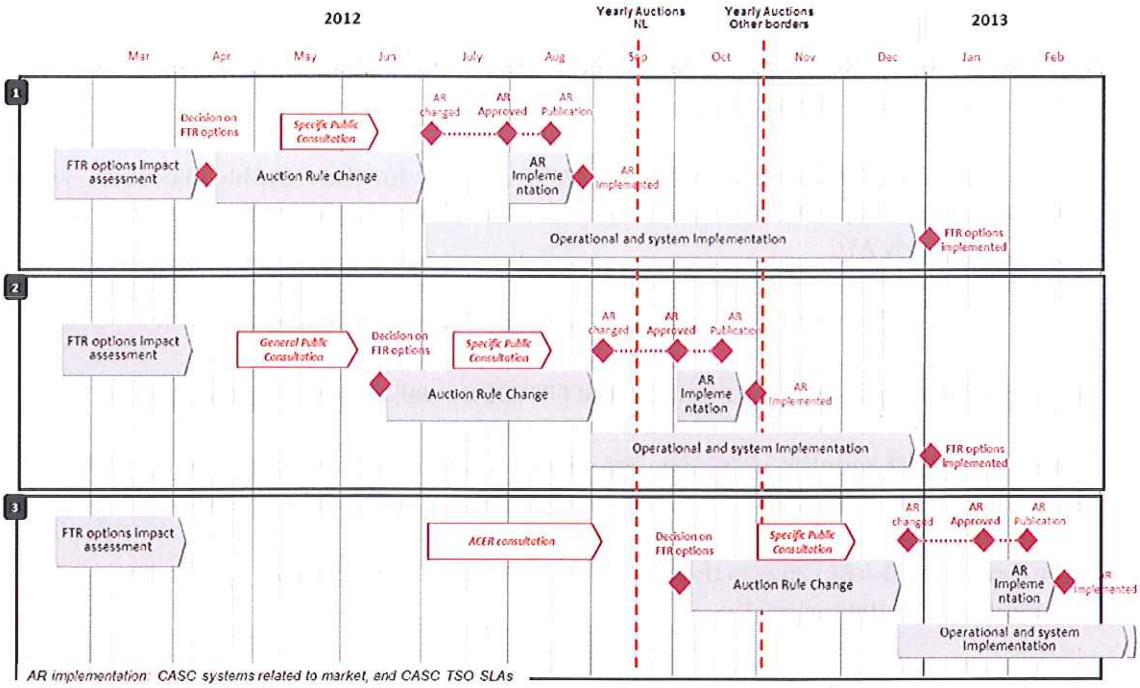

Figure 35 – Possible Scenarios for a Potential Introduction of FTRs in the CWE Area

Within the context already explained, ACER has launched a market consultation on long term products and their design options on August 29th 2012. Replies from market parties are expected by the third quarter of 2012 (the consultation will be closed on October 28th). This market consultation has been accompanied by the distribution to market parties of ENTSOE Educational Paper on Transmission Risk Hedging Products by the ACER Long Term Task Force. This market consultation covers the remaining items of CREG requests (in Epigraph 59 of Decision (B) 111110-CDC-1123), for the parts not contemplated in the FTR study mentioned before in this Chapter.

Additionally, exclusively for ELIA and RTE, all the previous is also meant to complete the very similar questions on FTR placed during the market consultation process held for Split Rules in the French-Belgian Border during 2011. The main conclusion of this consultation was that there seemed to be no consensus among market parties (at the time) on whether FTR should be implemented, nor when this should be done. However, it came out clear from questionnaire replies, that when choosing among FTR products market parties seemed to prefer FTR options (lower risk) and a regional approach for implementation (rather than a local one border-by-border). In general, when asked about the priority of FTR introduction, most respondents to the 2011 French-Belgian consultation placed this under a lower priority level than the one conferred to the implementation of CWE Flow Based, NWE Day Ahead market coupling and NWE Intraday market integration or the harmonization of the CWE/CSE auction rules.

Meanwhile, away from the French and Belgian borders, the German TSOs 50HZ and TENNET GMBH, together with the Danish TSO ENERGINET.DK, under the supervision of DERA (Danish NRA) and BENETZA (German NRA) are studying the possibility of whether to launch a market consultation on some Draft Auction Rules that would propose the introduction of Yearly and Monthly FTR at the German-Danish border (also including its DC part) already by the end of 2012 (December as the earliest) or early 2013.

7 Efficiency of Proposed Split Rules

Taking into account the findings of the analyses presented in this document, it was proposed to keep the Split Rules at the French-Belgian border as:

1. From the yearly NTC, reservation of 200 MW capacity for the monthly allocation (MAmin) and 200 MW of capacity for the daily allocation (DAmin), the remaining capacity being allocated as yearly ATC

   - ATCy =NTCy –MAmin –DAmin with MAmin =200 MW and DAmin =200 MW

   Aforementioned split rule holds for both the FR→BE as well as the BE→FR direction.

2. The remaining monthly NTC (i.e. the NTCm after deduction of the ATCy and capacity reservations for month (MAmin) and day allocation (DAmin)) is split as follows

   In the direction FR→BE: 25% to the monthly capacity and 75% to the daily capacity
   The month ATC is then equal to:

   - ATCm =MAmin +0,25 (NTCm –ATCy –MAmin –DAmin)

   In the direction BE→FR: 50% to the monthly capacity and 50% to the daily capacity
   The month ATC is then equal to:

   - ATCm =MAmin +0,50 (NTCm –ATCy –MAmin –DAmin)

In case the reserved capacities for month and day ahead are not available when determining the capacity to allocate at the monthly auction the available capacity will be equally allocated to the month and daily capacity.

All the mentioned split rules must be considered independent of any capacity resales from year to month (any capacity resale from year to month will be added to the ATCm).

Market parties have expressed in the past that whichever change Elia and RTE would introduce, it should not proof disruptive compared to the current market outcomes which have been generally recognized.

To assess the robustness of the proposed Split Rules ELIA and RTE have rerun the market coupling based on historical data (order books and NTCs) but taking into account the proposed Split Rules for 2011 as well as some more conservative assumptions regarding nominations behavior for both 2011 and 2012 (respectively 0%, 30% and 50% nominated year and month capacities).[15] The year ahead allocations are not changed as the sum of both day and month ahead reservations in the proposal is equal to the 400 MW reservation in past and current split rules.

Finally, we assume that non-economic nominations do not occur, which is motivated by the less than 1% occurrence ratios shown in Table 11 and Table 12. The assumed nomination levels of 30% and 50% are more conservative than the current nomination levels. These are depicted in Table 17. During the CWE Market Coupling period, in 2011, on average 12,35% of allocated capacity was

[15] It needs to be highlighted that these conservative nomination behavior has only been assumed for the BE-FR border and not for the other CWE borders.

nominated with respect to 13,68% in 2012. In the direction BE→FR, this ratio was 8,52% in 2011 and 6,71% in 2012. However at some moments the nomination level peaked at 29,2% in the direction France to Belgium (2011) and to 50,1% in the direction Belgium to France (also in 2011). These nomination peaks have been slightly lower in 2012 (with 24.6% for FR→BE and 49.1% for BE→FR, respectively). Hence, this confirms the choice of running the simulation also with conservative nomination levels to check the robustness of the proposed Split Rules also in stressed situations (which do sometimes occur) at the French-Belgian border. These increased nomination levels are maintained during the whole hours of the study period (which makes the test more strict).

The simulation with 0% nominations is made in order to roughly estimate the effect that cancelling all nominations would have, as with a potential introduction of FTR options. Notice, however, that the introduction of FTRs would probably have additional effects on market liquidity and other aspects (e.g. use of orders on both spot markets in combination of the FTRs to trade cross-border), that are not part of this simulation. Some of these impacts have been addressed by the studies referred to in the FTR Section of this document.

	FR→BE		BE→FR	
	Average Nominated Capacity [MW]	Average Ratio of Nominated Capacity to Allocated Capacity [%]	Average Nominated Capacity [MW]	Average Ratio of Nominated Capacity to Allocated Capacity [%]
2009	103	7.17	150	23.07
2010 (Nov. 10th)	39	2.62	190	28.09
Nov. 10th 2010 to Dec. 31st 2011	210	12.35	69	8.52
2012 (end of June)	239	13.68	54	6.71

Table 17: Overview of Total Nominated Capacities and Ratio to Total Allocated Capacity

Table 18 describes the impact of these 3 scenarios on CWE-price convergence for the CWE MC period (from January 1st 2011 until June 30th 2012).

Please notice that the overall price convergence is significantly reduced in 2012 with respect to 2011, due to the following facts. Year 2012 only uses 6 months and one of them (February) included the European Cold Wave, which produced significant decoupling and price spikes. There has been a significant increase in the lack of convergence of Germany and the Netherlands, with respect to the rest of the CWE area, in relation to the prior year. These two effects added together produce the reduction we observe in the figures, which is much less relevant for the case of Belgium and France as Table 19 demonstrates. In order to partially isolate one of these two effects a third row has been included for 2012 in which February is excluded from the first semester.

Price Convergence [%]	Sc1: @ 0% Nominations	Sc2: @ 30% Nominations	Sc3: @ 50% Nominations	Historical Price Convergence
2011	66.38%	66.07%	65.23%	65.75%
2012 (end of June)	46.02%	45.56%	44.18%	45.52%
2012 (end of June, without February)	50.93%	50.54%	49.16%	50.69%

Table 18: CWE-Price Convergence with Different Levels of Nominations

As it can be derived from the table above, under the proposed Split Rules, nomination patterns have a minor impact on price convergence in all scenarios. When looking at the price convergence between France and Belgium in Table 19, we again observe no significant change versus the historical convergence.

FR = BE [%]	Sc1: @ 0% Nominations	Sc2: @ 30% Nominations	Sc3: @ 50% Nominations	Historical Price Convergence
2011	99.84%	98.85%	96.42%	99.18%
2012 (end of June)	95.95%	91.53%	86.54%	92.88%
2012 (end of June, without February)	99.07%	95.97%	91.53%	97.82%

Table 19: Price Convergence between France and Belgium with Different Levels of Nominations

These simulations indicate that the available day ahead capacity for market coupling (ATCd-1) with the proposed Split Rules would still be high enough so as to guarantee a good level of price convergence under the most extreme cases of nomination observed during the study period, even if these are maintained for the whole hours of the year (whilst in reality more than 30% and more than 50% nominations have only occurred during 23% and 0.09% of the studied hours for the study period between January 2011 and June 2012) in the direction France to Belgium and even not occurred in the direction Belgium to France.

In Table 20, the ATCd-1 in the direction France to Belgium is shown. In this direction, the proposed Split Rules result on average in 335 MW in 2011 and 343 MW in 2012 less resales and resulting DA capacity for Scenario 2. For scenario 3, this results on average in 718 MW in 2011 and 695 MW in 2012 less resales and resulting DA capacity. Both results have not a significant impact on the expected price convergence for 2011 and 2012. It can be also observed, that a potential introduction of FTRs in this direction would have increased the ATC in 193 MW during 2011 and 185 MW during 2012.

ATC FR→BE (in MW)	Sc1: @ 0% Nominations	Sc2: @ 30% Nominations	Sc3: @ 50% Nominations	Historical ATC FR→BE
2011	2890 MW	2344 MW	1979 MW	2697 MW
2012(end of June)	3118 MW	2590 MW	2238 MW	2933 MW

Table 20: Average ATCd-1 in the Direction France to Belgium with Different Levels of Nominations

Also the direction BE→FR, the new split rules result on average in 419 MW in 2011 and 408 MW in 2012 for scenario 2 and 571 MW in 2011 and 557 MW in 2012 for scenario 3 less resales and resulting DA capacity without a significant impact on the expected price convergence for 2011 with respect to 2012. In this case the introduction of FTR options would have freed 192 MW of additional ATC in 2011 and reduced 186 MW in 2012, due to the impossibility of performing netting using the nominations in the opposite direction.

ATC BE→FR (in MW)	Sc1: @ 0% Nominations	Sc2: @ 30% Nominations	Sc3: @ 50% Nominations	Historical ATC FR→BE
2011	1424 MW	1197 MW	1045 MW	1616 MW
2012(end of June)	1728 MW	1506 MW	1357 MW	1914 MW

Table 21: Average ATCd-1 in the Direction Belgium to France with Different Levels of Nominations

When looking at the market prices for these Scenarios, in Table 22 we observe that the delta between the historical and the simulated prices does not result in a significant occurrence of price peaks for the CWE period (January 1st 2011 until June 30th 2012). However, the price peaks are for some hours significant (> 10€/MWh). Please notice that there is a clear impact on these figures (especially in the maximums and on the peak prices) due to the changes in the shared order book introduced because of the Cold Wave in February 2012 (during which 20-year-long, minimums in temperature were hit) which boosted energy demand (to an all-time record in France during this month reaching 102100 MW on the 8th of February 2012). This effect has consequences on the results of the values observed in the Tables. In order to try to isolate this effect, additional tables are included in which February 2012 is not taken into consideration.

For Scenario 1: @ 0% nominations

Delta In €/MWh	Delta BE	Delta DE	Delta FR	Delta NL
<-2	0.50%	0.08%	1.00%	0.19%
>2	1.12%	0.18%	0.08%	0.38%
<-5	0.25%	0.03%	0.39%	0.05%
>5	0.77%	0.04%	0.02%	0.15%
<-10	0.11%	0.00%	0.18%	0.01%
>10	0.47%	0.01%	0.00%	0.04%
Max Price Increase	170.00 €	13.48 €	7.75 €	23.86 €
Max Price Decrease	34.67 €	7.14 €	593.09 €	12.12 €

Table 22: Delta between Simulated Market Prices and Historical Market Prices in Scenario 1 with 0% Nomination (January 2011 to June 2012)

In the first scenario, with no nominations, the price in Belgium increased in more than 2 €/MWh in 2.30% of the concerned 10355[16] hours, i.e. 146 hours with respect to the historical price. For 62 hours, the price increase was more than 10€/MWh. The maximum increase of 170€/MWh occurred on the 9th of February. On that day, the largest price increases were recorded. The maximum price decrease was 593.09 €/MWh and took place on the 9th of February 2012. The largest price decreases are also recorded on that day and on the 10th of February 2012. This is due to the change in the ATC that the change in the nomination behavior would have brought forward under the conditions presented by the shared order book for the study period (which include the extreme conditions caused by the Cold Wave). It has to be noted, that without including February 2012, the 170 € price increase in Belgium would have been just 6 € and the 593 € price decrease in France would have amounted to just 1.8 €.

Delta In €/MWh	Delta BE	Delta DE	Delta FR	Delta NL
<-2	0.41%	0.01%	0.00%	0.17%
>2	0.03%	0.01%	0.05%	0.05%
<-5	0.24%	0.00%	0.00%	0.04%
>5	0.02%	0.00%	0.02%	0.02%
<-10	0.11%	0.00%	0.00%	0.00%
>10	0.00%	0.00%	0.00%	0.00%
Max Price Increase	€ 6.10	€ 2.01	€ 7.75	€ 6.09
Max Price Decrease	€ 34.67	€ 2.18	€ 1.83	€ 7.69

Table 23: Delta between Simulated Market Prices and Historical Market Prices in Scenario 1 with 0% Nomination (January 2011 to June 2012 with February 2012 excluded)

[16] February 4th 5th and March 28th are not included

Table 23 presents the same simulation for Scenario 1 without including February 2012 in the analysis. Results improve considerably in terms of price peaks thanks to the exclusion of the Cold Wave.

For Scenario 2 : @ 30% nominations

Delta In €/MWh	Delta BE	Delta DE	Delta FR	Delta NL
<-2	0.30%	0.09%	0.46%	0.18%
>2	1.18%	0.11%	0.07%	0.51%
<-5	0.11%	0.02%	0.15%	0.05%
>5	0.72%	0.02%	0.02%	0.21%
<-10	0.03%	0.00%	0.08%	0.01%
>10	0.37%	0.00%	0.00%	0.08%
Max Price Increase	43.84 €	9.07 €	7.75 €	17.06 €
Max Price Decrease	103.69 €	7.98 €	477.78 €	11.48 €

Table 24: Delta between Simulated Market Prices and Historical Market Prices in Scenario 2 with 30% Nomination (January 2011 to June 2012)

In the second scenario, the price increased only in 1,18% of the concerned hours (i.e. 154 hours) for more than 2 €/MWh versus the historical price. In 48 hours, the price increased in more than 10 €/MWh. The highest prices are mainly observed on July 14th 2011 (top 6 hours of the 48) with a maximum increase of 43,84 €/MWh. On July 14th 2011, Belgium was bilaterally coupled with France and Germany and the Netherlands are bilaterally coupled as well. Due to increased flows with France, Belgium is experiencing congestion at the border with France and sees either price increases, or is also coupling with high priced Germany and the Netherlands. The largest price decreases are mainly recorded the 9th and 10th of February 2012 (peak of the Cold Wave 2012 in France) and, thus, disappear from Table 25. The price increase situation improves in general (in Table 25), but the highest peaks are maintained due to July 14th 2011, as explained above.

Delta In €/MWh	Delta BE	Delta DE	Delta FR	Delta NL
<-2	0.14%	0.02%	0.06%	0.14%
>2	0.75%	0.02%	0.02%	0.34%
<-5	0.05%	0.00%	0.00%	0.03%
>5	0.50%	0.00%	0.02%	0.15%
<-10	0.00%	0.00%	0.00%	0.01%
>10	0.23%	0.00%	0.00%	0.06%
Max Price Increase	43.84 €	3.10 €	7.75 €	15.20 €
Max Price Decrease	8.96 €	2.53 €	2.99 €	11.48 €

Table 25: Delta between Simulated Market Prices and Historical Market Prices in Scenario 2 with 30% Nomination (January 2011 to June 2012 with February 2012 excluded)

For scenario 3: @ 50% nominations

Delta In €/MWh	Delta BE	Delta DE	Delta FR	Delta NL
<-2	0.94%	0.18%	0.66%	0.41%
>2	2.83%	0.15%	0.47%	1.38%
<-5	0.44%	0.02%	0.07%	0.05%
>5	1.82%	0.02%	0.11%	0.48%
<-10	0.21%	0.00%	0.01%	0.01%
>10	1.01%	0.00%	0.07%	0.25%
Max Price Increase	45.90€	6.67€	95.09€	27.73€
Max Price Decrease	103.69€	7.98€	11.59€	15.72€

Table 26: Delta between Simulated Market Prices and Historical Market Prices in Scenario 3 with 50% Nomination (January 2011 to June 2012)

In the 3rd Scenario shown in Table 26, the price increased in 2,83% of the concerned hours (i.e. 370 hours) in more than 2 €/MWh versus the historical price. In 53 hours (1,01%), the price increased in more than 10 €/MWh. In 27 hours, the price decreased with more than 10 €/MWh. The highest price peaks are mainly observed for on the 9th and 10th of February 2012 for France and on the 14th of July 2011 for Belgium. The Belgian situation on July 14th 2011 was due to high transits from France through Belgium, headed towards the Netherlands and Germany (since France had a lower price during the period), this caused congestion at the French-Belgian border and higher prices within Belgium. On this date, between 10h00 and 11h00, Belgium (at 51.10 €/MW) was decoupled from France (18.40 €/MW) and from the coupled Netherlands-Germany (at 58.56 €/MW). Between 18h00 and 19h00, Belgium was coupled with the Netherlands and Germany (at 49.49 €/MW) and all were decoupled from France (at 14.80 €/MW). The largest price decreases are observed on the 9th February 2012 (Cold Wave), therefore, these disappear from Table 27 (which does not consider February) together with the highest spike in France. The rest of the effects, due to the other reasons explained above, remain present.

Delta In €/MWh	Delta BE	Delta DE	Delta FR	Delta NL
<-2	0.40%	0.11%	0.66%	0.30%
>2	2.78%	0.08%	0.05%	1.34%
<-5	0.22%	0.00%	0.07%	0.02%
>5	1.83%	0.00%	0.02%	0.48%
<-10	0.04%	0.00%	0.01%	0.01%
>10	1.04%	0.00%	0.00%	0.27%
Max Price Increase	45.90 €	4.03 €	7.75 €	27.73 €
Max Price Decrease	15.13 €	3.94 €	11.59 €	15.72 €

Table 27: Delta between Simulated Market Prices and Historical Market Prices in Scenario 3 with 50% Nomination (January 2011 to June 2012 with February 2012 excluded)

As a conclusion, the simulations taking into account the proposed Split Rules and very conservative assumptions regarding the nomination behavior of market participants at the French-Belgian border, help to show that the proposed Split Rules are robust and do not significantly interfere in a negative manner with the average price convergence processes in the CWE-region, even when placed under stress conditions. These stress test conditions encompassed high level nominations in both directions on all hours of the year and the influence of the current shared order book, which contains only six months for 2012 and the full impact of the Cold Wave in France and its neighboring countries during February 2012.

It has to be clarified that the Split Rules 2010 were applied along the year 2011 and that the new proposed Split Rules have already been applied in 2012 (since they imply no changes with respect to their prior version, introduced in 2011). So for these comparative simulations of 2012 (end of June), the Split Rules set has not changed, only the nomination levels used.

Based on these results and considering the (by definition) approximate and imperfect character of any simulation, ELIA and RTE believe that the proposed Split Rules are robust and should not be disruptive compared to current market outcomes.

8 Proposed Capacity Split Rules

In line with the findings of the analyses presented in this document and the fact that there have been no significant changes in the main market fundamentals, we submit the following capacity Split Rules at the French-Belgian border to the CREG and CRE for approval:

1. From the year NTC, reservation of 200 MW capacity for the monthly allocation (MAmin) and 200 MW of capacity for the daily allocation (DAmin) (through market coupling), the remaining capacity being allocated as year ATC

   - ATCy =NTCy –MAmin –DAmin with MAmin =200 MW and DAmin =200 MW

The aforementioned Split Rule holds for both the FR→BE as well as the BE→FR direction.

2. The remaining month NTC (i.e. the NTCm after deduction of the ATCy and capacity reservations for month (MAmin) and day allocation (DAmin)) is split as follows

In the direction FR→BE: 25% to the monthly capacity and 75% to the daily capacity
The month ATC is then equal to:

   - ATCm =MAmin +0,25 (NTCm –ATCy –MAmin –DAmin)

In the direction BE→FR: 50% to the monthly capacity and 50% to the daily capacity
The month ATC is then equal to:

   - ATCm =MAmin +0,50 (NTCm –ATCy –MAmin –DAmin)

In case the reserved capacities for month and day ahead are not available when determining the capacity to allocate at the monthly auction, the available capacity will be equally allocated to the month and daily capacity.

All aforementioned split rules must be considered independent from any capacity resale from year to month (any capacity resale from year to month is to be added to the ATCm).

Concretely, this repartition between year, month and day ahead capacity gives the following results for different values of NTCy and NTCm in the direction France to Belgium as shown in Table 28 and Belgium to France as shown in Table 29.

In the direction France to Belgium

NTC y	NTC m	ATCy	ATCm	DA	Capacity ATCy+ATCm	Capacity DA
1600	1600	1200	200	200	88%	13%
	1700	1200	225	275	84%	16%
	1850	1200	262,5	387,5	79%	21%
	1950	1200	287,5	462,5	76%	24%
	2150	1200	337,5	612,5	72%	28%
	2350	1200	387,5	762,5	68%	32%

NTC y	NTC m	ATCy	ATCm	DA	Capacity ATCy+ATCm	Capacity DA
1700	1700	1300	200	200	88%	12%
	1850	1300	237,5	312,5	83%	17%
	1950	1300	262,5	387,5	80%	20%
	2150	1300	312,5	537,5	75%	25%
	2350	1300	362,5	687,5	71%	29%

NTC y	NTC m	ATCy	ATCm	DA	Capacity ATCy+ATCm	Capacity DA
1850	1850	1450	200	200	89%	11%
	1950	1450	225	275	86%	14%
	2150	1450	275	425	80%	20%
	2350	1450	325	575	76%	24%

NTC y	NTC m	ATCy	ATCm	DA	Capacity ATCy+ATCm	Capacity DA
1950	1950	1550	200	200	90%	10%
	2150	1550	250	350	84%	16%
	2350	1550	300	500	79%	21%

NTC y	NTC m	ATCy	ATCm	DA	Capacity ATCy+ATCm	Capacity DA
2150	2150	1750	200	200	91%	9%
	2350		250	350	85%	15%

NTC y	NTC m	ATCy	ATCm	DA	Capacity ATCy+ATCm	Capacity DA
2350	2350	1950	200	200	91%	9%

Table 28: Year Ahead, Month Ahead and Day Ahead Reserved Capacities with Proposed Split Rule for the Different Values of NTCy and NTCm in the Direction France to Belgium

In the direction Belgium to France

NTC y	NTC m	ATCy	ATCm	DA	Capacity ATCy+ATCm	Capacity DA
600	600	200	200	200	67%	33%
	700		250	250	64%	36%
	800		300	300	63%	38%
	900		350	350	61%	39%
	1000		400	400	60%	40%
	1200		500	500	58%	42%

NTC y	NTC m	ATCy	ATCm	DA	Capacity ATCy+ATCm	Capacity DA
700	700	300	200	200	71%	29%
	800		250	250	69%	31%
	900		300	300	67%	33%
	1000		350	350	65%	35%
	1200		450	450	63%	38%

NTC y	NTC m	ATCy	ATCm	DA	Capacity ATCy+ATCm	Capacity DA
800	800	400	200	200	75%	25%
	900		250	250	72%	28%
	1000		300	300	70%	30%
	1200		400	400	67%	33%

NTC y	NTC m	ATCy	ATCm	DA	Capacity ATCy+ATCm	Capacity DA
900	900	500	200	200	78%	22%
	1000		250	250	75%	25%
	1200		350	350	71%	29%

NTC y	NTC m	ATCy	ATCm	DA	Capacity ATCy+ATCm	Capacity DA
1000	1000	600	200	200	80%	20%
	1200		300	300	75%	25%

NTC y	NTC m	ATCy	ATCm	DA	Capacity ATCy+ATCm	Capacity DA
1200	1200	800	200	200	83%	17%

Table 29: Year Ahead, Month Ahead and Day Ahead Reserved Capacities with Proposed Split Rule for Different Values of NTCy And NTCm in the Direction Belgium to France

ELIA and RTE believe that the Proposed Split Rules:

- Introduce enough symmetry between import and export
- Allocate an adequate share of capacity to the long term horizon
- Prove to be robust and non-disruptive when tested with current market outcomes
- Comply with the last available feedback from market parties
- Make due consideration of the observations made by the CREG regarding the functioning of the auctioning of monthly capacity rights for the French-Belgian border

The proposal for capacity split is independent from the available NTCy at the BE-FR border as this latter will be determined following a coordinated process between all CWE TSOs early November 2012.

BIJLAGE 3

REGELS TOT VERDELING VAN DE CAPACITEIT TUSSEN VERSCHILLENDE PRODUCTEN OP GRENSVERBINDINGEN BELGIË-NEDERLAND

De toewijzing van de capaciteit op de grens België-Nederland gebeurt door toepassing van de bepalingen uit de Nederlandse grid code, met name artikel 5.6.6.1 en artikel 5.6.6.2.

"Art 5.6.6.1 Bij het veilen van de beschikbare landgrensoverschrijdende transportcapaciteit van de verbindingen Meeden-Duitsland, Hengelo-Duitsland, Maasbracht-Duitsland, Borssele-België, Geertruidenberg-België en Maasbracht-België worden de volgende categorieën transporten onderscheiden:
a. jaartransporten, te weten transporten met een looptijd van 1 januari tot en met 31 december;
b. maandtransporten, te weten transporten met een looptijd van 1 kalendermaand, te beginnen op de eerste dag van die maand;
c. spottransporten, met een looptijd van tenminste één klokuur en maximaal één kalenderdag.

Art. 5.6.6.2 Bij de toewijzing van de onder artikel 5.6.6.1 genoemde categorieën transporten worden de volgende uitgangspunten gehanteerd:
a. 1300 MW komt ter beschikking van de jaartransporten;
b. tenminste 400 MW en ten hoogste 850 MW komt ter beschikking van maandtransporten;
c. het restant van de voor de veiling gereserveerde landgrensoverschrijdende transportcapaciteit komt ter beschikking van spottransporten, met een minimum van 100 MW.
Alle landgrensoverschrijdende transportcapaciteit die niet conform artikel 5.6.11.1 is genomineerd, alsmede genomineerde capaciteit die het in artikel 5.6.11.3 genoemde maximum overschrijdt, komt eveneens ter beschikking van spottransporten."

In uitvoering van deze bepalingen hebben de betrokken TSO's op 1 november 2000 naar aanleiding van de start van de veilingen van capaciteiten op interconnecties van Nederland een akkoord gesloten over de verdeling van de capaciteit over de verschillende Nederlandse grenzen. Het betreft een akkoord tussen Elia, TenneT TSO B.V., TenneT TSO GmbH en Amprion.

Dit akkoord[1] voorziet volgende opdeling:

	Jaar (MW)	**Maand (MW)**	**Dag (MW)**	**% totaal aandeel**
Amprion – TenneT	522	377(*)	= Totaal **Amprion** -522-377(*)	Totaal Amprion = 39,6% van Totaal Nederlandse Grenzen
Elia – TenneT	468	313(*)	= Totaal ELIA-468-313(*)	Totaal ELIA = 36,4% van Totaal Nederlandse Grenzen
TenneT TSO GmbH – TenneT TSO B.V.	310	159(*)	= Totaal TenneT TSO GmbH -310–159(*)	Totaal TenneT TSO GmbH = 24,0% van Totaal Nederlandse Grenzen
Totaal Nederlandse Grenzen	1300	849(*)		

De capaciteiten gelden in beide richtingen.

(*) Dit betreffen de maximale waarden

[1] Het oorspronkelijke akkoord werd in 2007 aangepast naar aanleiding van het opheffen van de voorrang voor de SEP-contracten.