UNIVERSITÉ PARIS-DAUPHINE
ÉCOLE DOCTORALE DE DAUPHINE

THÈSE

Pour obtenir le grade de

Docteur de l'Université Paris-Dauphine

Discipline : Sciences Économiques

Présentée et soutenue publiquement par

Morgan HERVÉ (HERVÉ-MIGNUCCI)

le 13 décembre 2011

Titre :

RÔLE DU SIGNAL PRIX DU CARBONE SUR LES DÉCISIONS D'INVESTISSEMENT DES ENTREPRISES

sous la direction du Professeur Jan-Horst KEPPLER

JURY:

Directeur de thèse	**M. Jan-Horst KEPPLER**, Professeur des universités Université Paris-Dauphine
Rapporteurs	**M. Pierre-André JOUVET**, Professeur des universités Université Paris Ouest Nanterre La Défense
	M. Dominique FINON, Directeur de Recherche CNRS CIRED
Suffragant	**M. Christian de PERTHUIS**, Professeur associé Université Paris-Dauphine

Remerciements

Au terme de ces années de travail de thèse, je suis redevable à de nombreuses personnes pour m'avoir aidé et soutenu dans cette entreprise. Je tiens tout d'abord à remercier mon directeur de thèse, M. le Professeur Jan H. Keppler, pour la confiance qu'il m'a accordée et pour ses nombreux conseils. Je remercie également MM. les Professeurs Christian de Perthuis et Jean-Marie Chevalier pour m'avoir encouragé dans cette aventure.

Je remercie MM. les Professeurs Pierre-André Jouvet et Dominique Finon d'avoir accepté d'être les rapporteurs de cette thèse et pour leur participation au jury. Je remercie de nouveau M. le Professeur Christian de Perthuis pour m'avoir fait l'honneur de participer au Jury de soutenance.

J'ai eu également le plaisir de collaborer avec les équipes de CDC Climat Recherche et de la Chaire Economie du Climat. Je les remercie pour avoir eu la chance de partager avec eux ces dernières années pleines de brainstormings, de clubs Tendances Carbone et de bonne humeur. Je pense ici, plus particulièrement, à Benoit Leguet, Emilie Alberola, Valentin Bellassen, Malika Boumaza, Henri Casella, Ian Cochran, Mariana Deheza, Anaïs Delbosc, Jeremy Elbeze, Cécile Goubet, Jessica Lecolas, Alexia Leseur, Maria Mansanet-Bataller, Oliver Sartor, Suzanne Shaw, Boris Solier, Nicolas Stephan, Dorothée Teichmann et Raphael Trotignon.
La réalisation de cette thèse à été rendue possible grâce au soutien financier de la Caisse des Dépôts, de l'Institut CDC pour la Recherche et de l'ADEME. Je remercie en particulier Pierre Ducret, Jean-Pierre Sicard et Isabelle Laudier de la Caisse des Dépôts ainsi qu'Aude Bodiguel de l'ADEME pour leur confiance et leur soutien.
Je tiens à exprimer ma gratitude à l'équipe du Centre de Géopolitique de l'Energie et des Matières Premières (CGEMP/LEDa) de l'Université Paris-Dauphine et tout particulièrement Julien Chevallier et Sophie Meritet, Maîtres de Conférences au CGEMP, ainsi que Dominique Charbit et Iva Hristova.

Je remercie deux amis qui ont joué un rôle fondamental dans ma formation, Julien Mendoza et Stéphane Rouhier, pour m'avoir incité à faire cette thèse, pour les relectures et surtout pour le service après-vente.

Je pense très fort à Ingrid, ma compagne, et mes enfants, Garance et Calliste, pour avoir été à mes côtés ces dernières années et pour leur soutien infaillible. Je remercie Lancelot, Cécil et mes amis en dehors de la recherche pour leur compréhension sur mon léger manque de disponibilité ces dernières

années. Enfin, je dédie cette thèse à la mémoire de mes parents.

Abstract

This PhD thesis focuses on the impact of the European Union Emissions Trading Scheme (EU ETS) on investment decisions in the European power sector. We provide the policy background on the EU ETS and contemporary policy and economic developments. We discuss the main types of compliance buyers' responses to the EU ETS constraint: emissions reductions, acquisitions of additional compliance assets, and other responses. We present the results of an empirical survey of the most carbon constrained European utilities. We show that strategic and economic considerations prevailed over the introduction of the carbon price. We discuss the impact of those investments on European utilities' EU ETS profile by looking at the potentially locked-in emissions, changes in the compliance perimeter and some specific developments relative to carbon leakage and Kyoto offsets. We offer a review of the investment decision-making approaches. Exploring the impact of carbon price scenarios on generation investment portfolios, we are able to identify that: the EU ETS has a moderate but central reallocation role in power generation investment portfolios; insights into the long-term carbon price trend are particularly helpful to unlock investment; some much discussed policy provisions only have a relatively small impact on investment portfolios; carbon price expectations impact decisions relative to power generation investment portfolios; while the EU ETS has a central role, the climate and non-climate policy mix matters most.

Résumé court

Cette thèse porte sur l'impact du système communautaire d'échange de quotas d'émission (SCEQE) sur les décisions d'investissement dans le secteur électrique européen. Après une description du SCEQE et autres développements majeurs, nous discutons des principaux moyens qu'ont les acteurs de conformité pour faire face à la contrainte du SCEQE : réductions d'émissions, acquisition d'actifs carbone et autres types de réactions. Nous présentons les résultats d'une revue empirique des investissements par les producteurs d'électricité européens les plus contraints par le SCEQE. Les décisions d'investissement ont été davantage motivées par des considérations stratégiques et économiques que par l'introduction d'un prix du CO2. Nous discutons des impacts de ces investissements sur la conformité carbone des producteurs d'électricité européens : tonnes de CO2 potentiellement fixées par les investissements, changements de périmètres de conformité, mais également les fuites de carbone et recours aux mécanismes de projets. Enfin, nous explorons l'impact de scenarios de prix pour les quotas sur les portefeuilles d'investissement en capacité de production électrique. Nous montrons que : le SCEQE a un rôle modeste mais central dans la réallocation des portefeuilles d'investissement ; toute indication sur la tendance de prix de long terme du carbone est très utile ; certains éléments du SCEQE n'ont qu'un effet faible sur les investissements ; les anticipations de prix du carbone influencent les décisions liées aux portefeuilles d'investissement ; si le SCEQE joue un rôle central, c'est la combinaison de politiques de réduction des émissions et autres politiques qui compte le plus.

Résumé long

Cette thèse porte sur l'impact du système communautaire d'échange de quotas d'émission (SCEQE) sur les décisions d'investissement dans le secteur électrique européen. Nous explorons comment le secteur a fait face à l'introduction d'un prix du carbone. Nous fournissons une revue empirique des investissements dans le secteur depuis l'introduction du marché de quotas. Enfin, nous explorons l'impact de scénarios de prix pour les quotas sur les portefeuilles d'investissement en capacité de production électrique. Cette thèse se compose de trois chapitres.

Impact du marché européen de quotas sur les producteurs d'électricité européens

Le premier chapitre fournit une description du système communautaire d'échange de quotas d'émission (SCEQE) et explore les autres développements économiques et règlementaires majeurs. Le chapitre discute des trois principaux moyens qu'ont les acteurs de conformité pour faire face à la contrainte du SCEQE : des réductions d'émissions à court terme mais également à plus long terme, l'acquisition d'actifs de conformité supplémentaires et des réponses plus originales comme le lobbying ou l'ingénierie commerciale.

Le Groupe d'Experts Intergouvernemental sur l'Evolution du Climat (GIEC) a mis en lumière dans ses travaux la menace du changement climatique et son origine anthropogénique. Le protocole de Kyoto, adopté en 1997, est un accord international visant à réduire les émissions de gaz à effet de serre (GES), responsables du changement climatique. Les pays développés sont soumis à des objectifs de réduction de GES sur la période 2008-2012. Le protocole de Kyoto met en place un marché de quotas au niveau gouvernemental. Les états peuvent ainsi soit réduire leurs émissions soit obtenir davantage de quotas ou actifs provenant des mécanismes de projets (mise en oeuvre conjointe ou MOC et mécanisme pour un développement propre ou MDP). Ces mécanismes de projet permettent aux pays soumis à des objectifs de réduction de GES d'acquérir les tonnes de GES évitées (des crédits Kyoto) par la mise en place de projets de réduction de GES dans d'autres pays.

En 1998, les pays européens ont regroupé leurs objectifs de réduction de GES au niveau communautaire et organisé le transfert d'un grande portion de cet objectif (environ 40%) aux installations européennes de combustion de plus de 20 MW. C'est le système communautaire d'échange de quotas d'émissions (SCEQE ou EU ETS en anglais). Le SCEQE est également un marché de

quotas mais cette fois-ci au niveau des installations européennes émettant du dioxyde de carbone (centrales électriques, aciéries, cimenteries, raffineries, etc.). Ces installations pour être en conformité avec le SCEQE doivent soit réduire leurs émissions ou obtenir des actifs de conformité pour toute tonne de CO2 émise au-delà du plafond d'émissions propre à l'installation. Le SCEQE comporte trois phases de négoce : une phase pilote entre 2005 et 2007 (phase I), une phase coïncidant avec le protocole de Kyoto de 2008 et 2012 (phase II) et une phase post-Kyoto de 2013 à 2020 (phase III).

La méthode de détermination du plafond d'allocation européen (la contrainte carbone sur les installations de combustion) est commune à la phase I et II du SCEQE. Après avoir collecté des données techniques sur les installations de combustion tombant dans le champ d'application de la Directive européenne, les Etats membres européens préparent un plan national d'allocation de quotas (ou PNAQ) pour la Commission européenne. Cette dernière est chargée de valider l'allocation aux yeux de la conformité Kyoto des Etats membres. Le marché de quotas est ouvert aux installations soumises au SCEQE ainsi qu'aux intermédiaires financiers qui fournissent de la liquidité au marché. Lors de la phase I du SCEQE, la quasi-totalité des quotas a été allouée à titre gratuit aux installations sur la base de leurs émissions historiques. Le démarrage du marché prévu début 2005 a été plus lent que prévu, certains Etats membres ayant mis beaucoup plus de temps que prévu pour allouer leurs quotas. En avril-mai 2006, le marché européen de quotas a subi son premier choc informationnel avec la diffusion officielle des données sur les émissions de 2005. Le plafond d'émissions, auparavant perçu comme suffisamment bas, s'est avéré plus clément que prévu. Le prix du quota pour la phase I s'en est retrouvé divisé par trois dans la foulée. Etant données les difficultés techniques et institutionnelles pour la connexion entre le registre ONU des crédits Kyoto et le registre européen de quotas (CITL), l'utilisation de crédits Kyoto pour la conformité des installations n'a pu avoir lieu lors de la phase I.

La phase II du marché européen de quotas (2008-2012) a vu un resserrement de la contrainte qui pèse sur les installations mais également un élargissement de son champ d'application aux nouveaux Etats membres et pays de la zone AELE (Norvège, Lichtenstein et Islande) et à des GES autres que le CO2. L'étape de validation des PNAQ pour la phase II a vu la Commission européenne retoquer plus d'un projet d'allocation. Au final, les allocations prévues par les PNAQ soumis ont été réduites de plus de 10% lors des révisions de la Commission. Cette étape de révision plus longue que prévue et la contestation des révisions par certains Etats membres (allant jusqu'à saisir la Cour de justice de l'Union européenne) a de nouveau causé des délais dans les allocations de quotas aux installations. L'utilisation de crédits Kyoto pour la conformité des installations s'est concrétisée lors de cette phase avec l'apparition d'un signal prix pour les crédits Kyoto secondaires issus du MDP (CERs secondaires). Le prix des CERs secondaires est en décote par rapport à celui des quotas européen. En revanche, le recours aux crédits Kyoto pour la conformité des installations est limité par des plafonds propres à chaque Etat membre (entre 0 et 20% des actifs de conformité restitués pour 13,5% en moyenne). Le prix des quotas lors de la phase II du marché européen a été plus stable que lors de la phase pilote du marché et a oscillé entre 10 et 25 euros. Le prix, bien que sensible aux annonces institutionnelles (PNAQ et éléments concernant la phase III), s'est montré bien plus réactifs aux fondamentaux du marché (météorologie, prix relatifs des énergies et demande aux industriels). La phase II du marché a également vu un recours légèrement plus important aux enchères de quotas.

La phase III du marché (2013-2020) est marquée par des changements majeurs par rapport aux précédentes phases de négoce de quotas. Premièrement, le processus d'allocation ne commence plus au niveau des Etats membres mais au niveau communautaire pour être ensuite translaté au niveau des installations. Deuxièmement, l'allocation de quotas ne se fera plus majoritairement à titre gratuit. Il est en effet prévu une montée en puissance progressive du recours aux enchères de quotas avec comme objectif 100% d'enchères en 2020. Les allocations à titre gratuit se concentrent sur les installations industrielles les plus exposées à la concurrence internationale et aux potentielles fuites de carbone. Pour celles-ci, des benchmarks spécifiques plutôt que les émissions historiques sont utilisés pour allouer les quotas. Troisièmement, l'objectif de réduction de GES à horizon 2020 est passé à 20% par rapport à 2005. Le relèvement de cet objectif à 25% ou 30% a fait et fait toujours l'objet de discussion. Quatrièmement, l'utilisation des crédits Kyoto obtenus lors de la phase II est autorisée pour la conformité des installations en phase III.

En parallèle du marché européen de quotas, plusieurs mécanismes incitatifs aux réductions de GES dans le secteur électrique européen ont vu le jour. Un premier groupe de politiques cible les premières étapes du cycle de vie des technologies de production d'électricité peu ou pas carbonée. Il s'agit de l'ensemble des mécanismes de soutien à la recherche et au développement ou au soutien direct à la capture et séquestration du carbone (CSC) et aux renouvelables les moins matures (projets pilote notamment). Un deuxième groupe de politiques s'attache à favoriser le déploiement des énergies renouvelables plus ou moins matures (éolien terrestre et maritime, photovoltaïque, géothermie, etc.) à l'aide de tarifs de rachat ou de certificats verts. L'objectif de ces politiques est de tirer les coûts de production de ces technologies vers les prix de marché de l'électricité afin de les rendre compétitives avec notamment les technologies à base de carburants fossiles.

Une autre tendance de fond sur les premières années de la phase II du marché européen de quotas a été l'émergence d'une crise économique et financière sans précédent fin 2008. Au-delà des impacts généraux sur l'économie (institutions bancaires sous pression, effets des politiques monétaires, etc.), la crise a affecté les déterminants des choix d'investissement dans les capacités de production électrique mais aussi le fonctionnement du marché européen de quotas. Concernant les choix d'investissement, les conditions de financement de centrale électriques se sont détériorées sur fond de primes de risque accrues tant pour les investisseurs que pour les banques prêtant des capitaux. Les rendements attendus sur les centrales ont été revus à la baisse tant la crise semble s'être installée dans la durée. Enfin, la demande même pour de nouvelles capacités de production électrique a été remise en question étant données les perspectives de demande aux industriels. En ce qui concerne le marché européen de quotas, la crise a provoqué une baisse de la demande pour les quotas. Le prix du quota s'est donc ajusté à la baisse sur la période facilitant la conformité des installations émettrices de dioxyde de carbone. Par ailleurs, les installations européennes sous pression à cause de la détérioration du climat économique et commercial ont monétisé leurs allocations de quotas obtenus à titre gratuit afin de dégager des liquidités supplémentaires.

La prise en compte de la contrainte carbone par les producteurs d'électricité européens commence par une évaluation de l'exposition du groupe (de ses unités de production électrique) aux prix du carbone. Les premières tâches consistent à faire l'inventaire des installations soumises au SCEQE, à obtenir un historique des émissions de CO2 et les caractéristiques techniques de ces installations. Sur la base de projections de production électrique sur la durée du SCEQE et de son allocation de quotas, le groupe énergétique est en mesure de prévoir ses émissions de CO2 mais surtout la part d'entre elles qui ne sera pas couverte par l'allocation initiale de quotas. L'étape suivante consiste à chiffrer cette exposition en fonction de scénarios de prix. Enfin, le groupe énergétique élabore des courbes de coûts marginaux d'abattement pour le CO2 afin de guider sa stratégie de conformité entre réduction des émissions et acquisition d'actifs de conformité supplémentaires. En effet, chaque année et pour toutes les installations soumises au SCEQE, il doit y avoir une égalité entre émissions vérifiées et actifs de conformité restitués.

Tout d'abord, les électriciens européens ont souvent eu recours à des réponses au SCEQE qui s'inscrivaient dans une courte durée. Un premier levier a consisté à incorporer le prix du carbone dans les processus d'optimisation des opérations au niveau de la production d'électricité. Le principal impact a été le changement de l'ordre d'appel des carburants pour la production d'électricité - si bien que le prix de bascule du CO2 (prix théorique du carbone pour lequel la marge de production à partir du charbon équivaut à celle à partir de gaz naturel) a joué un rôle central dans la détermination du prix de marché pour le carbone. Certaines centrales capables de brûler différents types de carburants fossiles ont pu réduire leurs émissions de carbone de la sorte. Un second levier a consisté à acquérir d'autres actifs de conformité et à déployer une réelle stratégie de gestion du risque carbone. Le principal moyen de se fournir des quotas hors allocation initiale a été d'en faire l'acquisition sur des bourses carbone, via des courtiers ou dans le cadre de transactions directes avec d'autres acteurs de conformité. Ces acquisitions se sont faites au comptant mais surtout à terme en ayant recours à des contrats de gré à gré ou standardisés sur les places de marché carbone. L'avantage est d'assurer la conformité carbone dans la durée plutôt que d'année en année. En dehors des quotas, certains acteurs de conformité ont fait l'acquisition de CERs secondaires dans les limites fixées par les PNAQs. Enfin, certains acteurs de conformité ont fait usage des quotas attribués pour des années antérieures ou ultérieures. Un dernier levier qui s'inscrit un peu moins dans le court terme a consisté à acquérir des portefeuilles de crédits Kyoto (CERs primaires principalement) adossés à des projets de réductions de GES dans les pays en développement. Trois types de projets ont vu la participation des électriciens européens : les projets MDP correspondant à leur coeur d'activité (production d'électricité décentralisée et renouvelables), les projets MDP à bas coût et haut rendement en termes de crédits (HFC-23 et N20) et les projets s'assurant des impacts en terme de développement.

Le deuxième groupe de leviers d'action correspond aux réponses en termes d'investissements. La première possibilité est l'investissement dans les centrales électriques existantes : augmentation de la capacité des centrales (en changeant ou non le carburant utilisé), remplacement d'une technologie par une autre (gaz naturel au lieu de pétrole), modification des caractéristiques des centrales (installation d'un module de capture du CO2, amélioration du rendement thermique ou chaudière permettant l'utilisation de plusieurs carburants), prolongement de la durée de vie des centrales ou fermeture temporaire ou définitive des centrales. La deuxième possibilité consiste à investir dans de nouvelles centrales qui seraient mieux à même de supporter la contrainte carbone. La troisième possibilité plus dans le long terme correspond à tous les investissements en recherche et développement (amélioration du rendement des centrales, CSC, renouvelables, mini-cogénération, etc.).

Le dernier levier d'action employé par les électriciens européens pour faire face au SCEQE a été de recourir à des stratégies en dehors des ajustements opérationnels, du négoce de quotas et des investissements. Le SCEQE a en effet entrainé la constitutions d'équipes dédiées à la conformité carbone au sein des électriciens européens. Cette action s'est articulée autour des activités des desks de trading et d'entités centrées sur les projets MDP et MOC. Cette stratégie a donné aux électriciens une meilleure maîtrise du risque carbone. Une autre stratégie a consisté à incorporer le risque carbone dans l'ingénierie commerciale de ces groupes (contrats de long terme, échange de capacité de production électrique, etc.). Enfin, une dernière stratégie à consisté à déployer des efforts de lobbying et juridiques afin d'essayer de réduire le niveau de la contrainte.

Investissements en capacité et prises de participation par les électriciens européens entre 2004 et 2009 : quelle rôle pour les politiques climatique européennes ?

Le deuxième chapitre présente les résultats d'une revue empirique des investissements physiques et financiers par les cinq producteurs d'électricité européens les plus contraints par le marché de quotas. Nous montrons qu'en dehors des années les plus récentes, les décisions d'investissement ont davantage été motivées par des considérations stratégiques et économiques que par l'introduction d'un prix du carbone. Nous discutons des impacts de ces investissements sur la conformité carbone des producteurs d'électricité européens : tonnes de carbone potentiellement fixées par les investissements dans de nouvelles centrales mais aussi dans les centrales existantes ; changements de périmètres de conformité causés par les prises de participations de ces groupes ; mais également des éléments liés aux fuites de carbone, aux recours aux mécanismes de projets Kyoto, et aux retards et annulations de projets de centrales.

L'introduction d'un prix du carbone a causé de nombreuses transformations dans le secteur électrique européen. Néanmoins, les premières évaluations semblent indiquer que les impacts en termes d'investissements aient été plus limités. Ce chapitre s'intéresse donc au rôle qu'a pu jouer le SCEQE dans les décisions d'investissement des électriciens européens à travers la revue empirique des investissements des cinq électriciens européens les plus contraints par le SCEQE (RWE, E.ON, Vattenfall, Enel et EDF) sur la période 2004-2009. Ces cinq groupes ont à eux seuls, un plafond d'émissions de CO2, équivalent au quart du plafond européen du SCEQE.

Etant donnée l'absence d'une base de données fiable couvrant investissements, désinvestissements et prises de participation dans le secteur, cette revue empirique se base sur un travail de collecte et de retraitement de données provenant de rapports annuels, de communiqués de presse et autres sources officielles. La revue empirique couvre à la fois investissements en capacité (construction de centrales, investissements dans des centrales existantes) et prises de participation (entrée au capital, augmentation ou réduction des participations, échanges de participations et désinvestissement).

Concernant les investissements en capacité, la revue empirique couvre 254 opérations (111 réalisées pour près de 14 GW et le reste à l'état de projet pour plus de 92 GW). Pour les projets achevés entre 2004 et 2009, les technologies de choix ont été les énergies renouvelables (70% des projets réalisés pour 35% de la capacité installée supplémentaire) et les centrales à gaz (21% des projets réalisés pour 58% de la capacité installée supplémentaire). Les centrales éoliennes maritimes et hydrauliques ont été les principales contributrices à la percée des renouvelables. Concernant les centrales à gaz installées sur la période (principalement en Italie, Espagne et Pays-Bas), deux tendances de fond ont été observées : de nouvelles centrales à haut rendement thermique (pour 6,7 GW) et des remplacements de capacité (pour 1,2 GW). Pour les projets annoncés entre 2004 et 2009, les technologies de choix sont plus variées : à la première place viennent les projets de centrales à charbon et lignite (près de 29 GW), puis les centrales à gaz (près de 27 GW), les centrales nucléaires (plus de 15 GW) et les énergies renouvelables (13 GW). Les projets d'ajout de centrales à charbon et lignite (à haut rendement le plus souvent) se concentrent sur l'Allemagne, les Pays-Bas, le Royaume-Uni, l'Italie et les Balkans. Du côté des projets d'énergies renouvelables, le principal contributeur est l'éolien (maritime et terrestre).

Concernant les activités de prise de participation, la revue empirique couvre 336 opérations (194 prises de participations, 127 désinvestissements et le reste en échange de participations). La revue empirique a permis d'identifier trois tendances de fond pour les prises de participation sur la période. Premièrement, le secteur sur 2004-2009 a vu de nombreuses transactions de fusion et acquisition (Enel et Endesa, EDF et British Energy ou encore Vattenfall et Elsam). Cette tendance a concerné plus de quatre opérations sur cinq. Deuxièmement, les cinq électriciens ont investi en Europe de l'est et dans sa région périphérique dans la foulée de la libéralisation des marchés énergétiques. Les taux de croissance du PIB prévus y sont effectivement plus importants que dans les pays dans lesquels ces électriciens sont historiquement présents. Parmi les autres avantages, une proximité géographiques des marchés existants et une régulation moins présente. Troisièmement, les groupes énergétiques ont fait l'acquisition ou ont augmenté leurs participations dans les développeurs d'énergies renouvelables (certains renouvelables sont également passés sous le giron de ces groupes via les transactions de fusion et acquisition). La cession de prises de participation a répondu à plusieurs logiques - les deux principales ayant été un repositionnement stratégique des *utilities* vers un modèle d'énergéticien européen d'un côté et une obligation réglementaire ou commerciale du fait des transactions majeures de fusion et acquisition. Enfin, les dernières années de l'échantillon ont vu la montée en puissance des transactions (échanges de capacité ou de titres) dont la contrepartie était une combinaison de capacité de production, titres et liquidités pour la soulte.

L'analyse de l'impact des investissements en capacité sur le profil des émissions carbone montre que près de 8,7 GtCO2 seraient potentiellement émises par les centrales électriques sur leur durée de vie (454 MtCO2 pour celles installées entre 2004 et 2009 et le reste pour celles à l'état de projet). Le principal contributeur est bien entendu la capacité prévue de centrales à charbon et lignite. Néanmoins ces centrales sont des candidates idéales pour des modules de capture du dioxyde de carbone. Sans l'existence d'un scénario "au fil de l'eau" d'investissements dans des centrales pour les cinq électriciens européens (i.e. un scénario contrefactuel sans SCEQE), il est difficile d'identifier des réductions d'émissions causées par le SCEQE.

L'analyse des prises de participation sur le périmètre d'exposition au SCEQE indique que 8,4 GW de capacité de production à base de charbon et lignite (nets de cessions de participations à des tiers) ont été ajoutés au périmètre de consolidation des cinq groupes énergétiques. Les opérations de fusion et acquisition et l'expansion vers l'est expliquent cette évolution. Si l'on rajoute les centrales à gaz, au pétrole et autres centrales émettrices de dioxyde de carbone, l'analyse montre que 22,6 GW nets de capacité de production émettrice de GES sont passés dans le giron des cinq électriciens sur 2004-2009. Sur la même période, l'analyse indique que 21,7 GW nets de capacité production non-émettrice de dioxyde de carbone (nucléaire et renouvelables) ont été transférés dans les livres des électriciens, soit un peu moins. Le tableau change lorsque l'on rajoute les projets de participation inachevés : 24,4 GW nets pour la capacité de production émettrice contre 30,5 GW nets pour la capacité de production non-émettrice. Cette avance repose néanmoins sur l'hypothèse que les projets seront bel et bien développés et que les mécanismes de soutien aux renouvelables seront maintenus.

Enfin, certains développements relatifs au SCEQE ont eu lieu sur la période. Certains projets de capacité de production identifiés ont un potentiel de fuite de carbone important (notamment un projet de 800 à 1,600 MW de capacité de production à base de charbon en Albanie avec une ligne de transmission vers l'Italie). Par ailleurs, l'analyse montre que les mécanismes de projets Kyoto ont favorisé l'expansion à l'est avec la MOC et en Amérique Latine avec le MDP. Enfin, les projets de centrales à charbon ou lignite et de CSC ont été annoncés, retardés, ou annulés en fonction des développements réglementaires sur les allocations de phase III et les mécanismes de support à la CSC.

Impact du marché européen de carbone sur les ajouts de capacité de production : approche de type options réelles

Le troisième chapitre débute par une revue de la littérature sur les décisions d'investissement. Nous montrons les avantages mais également les difficultés à avoir recours à un modèle d'options réelles. Nous explorons ensuite l'impact de scénarios de prix pour les quotas sur les portefeuilles d'investissement en capacité de production électrique. Nous montrons que : (1) le SCEQE a un rôle modeste mais central dans la réallocation des portefeuilles d'investissement en capacité de production électrique; (2) toute indication sur la tendance de prix de long terme du carbone est particulièrement utile pour débloquer les investissements en capacité de production; (3) certains amendements ou éléments du marché européen de quotas, bien que largement débattus (mécanismes de soutien aux prix et réserve pour les nouveaux entrants notamment), n'ont qu'un effet faible voire négligeable sur les décisions d'investissement; (4) les anticipations de prix pour le carbone influencent les décisions liées aux portefeuilles d'investissement en capacité de production, retards et annulations de projets; (5) si le SCEQE joue un rôle central, c'est la combinaison de politiques de réduction de gaz à effet de serre et autres politiques publiques qui compte le plus.

Les décisions d'investissement s'appuient sur différentes méthodes et critères d'aide à la décision. La méthode la plus utilisée par les professionnels est celle des flux de trésorerie actualisés (*discounted cash flows* ou DCF en anglais). La valeur des flux futurs de trésorerie est convertie en euros d'aujourd'hui. La somme des coûts d'investissement et des flux de trésorerie actualisés donne la valeur actuarielle nette (VAN ou *net present value* - NPV). Si la VAN est positive, l'investissement sera rentable. Cependant, la méthode des flux de trésorerie actualisés dans sa version classique souffre de deux inconvénients : son manque de prise en compte de la flexibilité et son manque de prise en compte de l'incertitude. La littérature sur les méthodes de décision d'investissement et sur les critères d'aide à la décision a vu apparaître plusieurs alternatives ou compléments aux méthodes de flux de trésorerie actualisés. Les taux d'actualisation peuvent être ajustés pour prendre au mieux en compte le risque lié à l'investissement. L'utilisation de scénarios permet de prendre en compte davantage d'incertitude dans les projections de flux de trésorerie futurs. Les tests de sensibilité permettent d'identifier les éléments déterminants pour la VAN. Le recours à des simulations (notamment de Monte Carlo) permet de prendre en compte l'incertitude de manière plus élaborée qu'avec les scénarios. L'ajout d'une contrainte budgétaire permet d'envisager les choix d'investissement dans un contexte de multiples opportunités d'investissement. Enfin, l'utilisation d'arbres de décisions permet de valoriser la flexibilité des investisseurs dans les choix d'investissement et de gestion des centrales.

En réponse aux limitations des approches traditionnelles de valorisation des investissements, la méthode des options réelles (Dixit et Pindyck, 1994 et Trigeorgis, 1996) essaie de capturer davantage de sources de valeur et d'incertitude. Au départ ancrées dans les méthodologies de valorisation des options financières, les approches de types options réelles ont su s'affranchir des restrictions inhérentes pour parvenir à une valorisation plus réaliste des investissements. Tout d'abord, la méthode des options réelles laisse à l'investisseur de la flexibilité dans la date d'investissement et dans les modes de gestion des opérations (arrêt et redémarrage de la production, changement des carburants, production de chaleur et / ou électricité). Par ailleurs, la méthode des options réelles permet une modélisation plus fine des sources d'incertitude (allant de prises en compte relativement simples au recours à des processus stochastiques). Enfin, la méthode des options réelles considère que les investissements sont irréversibles contrairement aux flux de trésorerie actualisés. Néanmoins, les modèles de type options réelles sont plus complexes à résoudre. Parmi les approches pour résoudre ces modèles, le recours relativement récent à des simulations, mêlant Monte Carlo et *backward induction*, ouvre des perspectives de résolution de cas de plus en plus réalistes.

La méthode des options réelles a été souvent appliquée à la valorisation des centrales électriques (valorisation individuelle d'actifs de production, valorisation comparative d'investissements exclusifs, planification d'investissements et déploiement de technologies). Récemment, quatre types d'articles consacrés à l'incertitude du prix du carbone pour les centrales électriques ont été publiés. Un premier groupe de papier s'attache à évaluer la valeur d'option qu'ont les centrales électriques disposant d'une flexibilité opérationnelle (Laurikka, 2005 ; Abadie et Chamorro, 2008). Ces articles montrent que la flexibilité face à un prix du carbone incertain ajoute de la valeur. Un deuxième groupe d'articles cherche à quantifier le risque supplémentaire causé par les politiques de réduction des GES (Yang et Blyth, 2007). Un troisième groupe d'articles effectue des valorisations comparatives entre plusieurs technologies de production d'électricité plus ou moins émettrices de CO2 (Laurikka et Koljonen, 2006 ; Sekar, 2005 ; Fuss et al., 2008 ; Szolgayova et al., 2008). Un dernier groupe d'articles explore les aspects de planification d'investissement et de déploiement de technologies face à des politiques climatiques incertaines (Fuss et al., 2009). Le modèle développé dans cette thèse se revendique de ce dernier groupe d'article.

Le modèle d'options réelles utilisé dans cette thèse s'intéresse au cas d'un nouvel entrant sur le marché de la production électrique qui dispose d'une fenêtre de tir de dix ans pour investir dans une combinaison de plusieurs technologies (nucléaire, CCGT, charbon sans CSC, charbon avec CSC et éolien maritime) sous contrainte budgétaire. Le nouvel entrant a la flexibilité de choisir quand investir dans les technologies de production et dans quelle combinaison de technologie. Le modèle prend en compte l'incertitude dans les prix du carbone et de l'électricité. Ainsi chaque année, (1) le nouvel entrant observe l'état de plusieurs variables économiques (le budget restant, les prix stochastiques du carbone et de l'électricité, les tarifs de rachat pour l'éolien et les prix déterministes des carburants fossiles), (2) décide d'investir dans une combinaison de technologies de production ou attend tant que la fenêtre de tir n'expire pas et que le budget n'a pas été épuisé et (3) reçoit en échange la VAN correspondant à l'investissement dans la combinaison de technologies retenue. Le nouvel entrant va chercher à maximiser son retour sur investissement en prenant en compte la flexibilité dont il dispose sur les choix de technologie et le *timing* d'investissement ainsi que la contrainte budgétaire.

Les premiers efforts de modélisation du prix du carbone dans la littérature se sont attachés soit à expliquer l'évolution du prix à la lumière de facteurs fondamentaux (Alberola et al., 2008 ; Mansanet-Bataller et al., 2007 ; Alberola et Chevallier, 2009) soit à fournir des modèles pour le *pricing* de produits dérivés (Benz et Truck, 2008 ; Daskalakis et al., 2007). Cependant, le court historique de prix fait qu'il est difficile de se baser sur ces papiers pour modéliser des prix du carbone sur plusieurs décennies. Nous modélisons le prix du carbone comme une variable stochastique continue. La littérature sur les options réelles appliquée aux centrales électriques offre deux alternatives à la forme fonctionnelle du processus stochastique du carbone : un mouvement brownien géométrique dans la plupart des papiers et, dans d'autres un processus de retour vers la moyenne. Nous retenons un processus stochastique de retour vers une moyenne, elle même définie par une équation linéaire, afin de capturer une tendance de coût d'abattement du carbone qui évolue dans le temps. Le prix du carbone est constitué d'une composante de court terme soumise à volatilité mais retournant vers la composante de long terme (coût d'abattement du carbone) en fonction d'un paramètre de vitesse de retour à la moyenne. Le processus stochastique est calibré de manière économétrique (maximisation des vraisemblances) sur des données de la bourse carbone ECX; puis le taux de croissance du coût d'abattement du carbone est ajusté manuellement pour refléter un prix de 40 euros à horizon 2030, en ligne avec les projections des analystes du marché. Un processus stochastique similaire est retenu pour les prix de l'électricité en base et en pointe (calibré à partir de données EEX / Powernext). Le tarif de rachat pour l'éolien maritime est calqué sur le modèle français et les prix des carburants fossiles se basent sur des projections de l'AIE et des données de marché.

Le nouvel entrant a la possibilité d'investir dans cinq types de centrales. La centrale à gaz à cycle combiné (CCGT) a un coût d'investissement moyen mais est exposée à des prix du gaz historiquement volatils et à un coût du carbone modéré. La centrale à charbon sans CSC a un coût d'investissement plus important que la CCGT mais son exposition à des prix de carburant volatils est limitée. En revanche, son coût du carbone est plus important et elle bénéficie d'un haut rendement thermique. La variation avec CSC a un coût d'investissement encore plus important, un rendement thermique réduit mais une exposition au prix du carbone quasiment éliminée. Du côté des technologies non émettrices de dioxyde de carbone, le nouvel entrant peut investir dans une centrale nucléaire avec le coût d'investissement initial le plus important mais le coût marginal de production le plus faible. Enfin, le nouvel entrant peut investir dans un parc d'éoliennes maritimes pour un coût d'investissement conséquent mais aucun coût lié à des carburants ou au carbone.

Le modèle est résolu en appliquant le principe d'optimalité de Bellman (1955) dans un cadre d'options réelles moderne (approche de Monte Carlo avec régression par moindres carrés - Longstaff et Schwartz, 2001 ; Gamba, 2003) que nous adaptons pour permettre la prise en compte d'une contrainte budgétaire. Nous commençons par générer de manière aléatoire un nombre important de trajectoires de prix pour l'ensemble des variables stochastiques. Puis nous calculons l'ensemble des VAN individuelles (propres à chaque technologie) pour chacune des trajectoires de prix et chacune des années de la fenêtre de tir. Nous déterminons les combinaisons de technologies possibles en fonction du budget restant et des coûts d'investissement. Le processus de *backward induction* commence alors. Nous partons de la dernière année (t=10) et déterminons la valeur terminale optimale et le choix d'investissement associé pour chaque niveau de budget possible. Nous passons alors à l'avant dernière année (t=9) où nous sommes confrontés au choix d'investir cette année-là (bénéfice instantané ou *immediate reward*) ou d'attendre l'année suivante pour investir (bénéfice futur actualisé ou *discounted continuation value*). Le bénéfice futur actualisé est estimé par la méthode des moindres carrés en se servant des valeurs pour t=10. Nous déterminons alors les combinaisons de technologies possibles en fonction du budget restant et des coûts d'investissement en t=9. Nous remontons ainsi jusqu'à la première décision en t=0 pour laquelle le budget est connu. Nous sommes alors en mesure de déterminer la chaîne de décisions qui maximise la valeur extraite de cette opportunité d'investissement. A partir de cette chaîne de décisions, nous calculons les tonnes de CO2 potentiellement émises par les centrales dans lesquelles le nouvel entrant envisage d'investir.

La calibration initiale du modèle indique que l'investissement optimal est d'épuiser l'intégralité du budget dès la première décision pour investir dans des CCGTs. Cette décision fige potentiellement quelques 150 MtCO2 dans l'atmosphère sur la durée de vie des centrales. Plusieurs tests de sensibilités montrent un manque de diversification dans les décisions optimales, tant dans le *timing* que dans les choix technologiques. Etant donné que notre question de recherche n'est pas de comparer plusieurs technologies de production d'électricité entre elles mais de développer des scénarios autour de portefeuilles d'investissement, nous modifions les conditions du modèle pour augmenter la granularité des résultats et nous permettre de capturer les effets d'options réelles et les effets de reports technologiques en fonction du prix du carbone. Nous limitons donc l'investissement dans les centrales CCGTs à deux au maximum. L'investissement optimal devient deux CCGTs et trois parcs éoliens maritimes en t=0.

Après avoir présenté les spécifications du modèle, nous explorons les questions d'impact des politiques de réduction de GES à travers des tests de sensibilité sur (1) le prix du carbone, (2) les paramètres hors prix du SCEQE et (3) les politiques de soutien direct à une technologies (renouvelables et CSC).

Nous commençons l'étude des impacts des politiques climatiques sur les investissements d'un nouvel entrant par des tests de sensibilité aux prix du carbone. Dans notre modèle, la dynamique de court terme est capturée par deux forces qui s'opposent : un paramètre de volatilité qui fait dévier le prix du carbone de son prix d'équilibre de long terme et un paramètre de vitesse de retour à la moyenne qui force le retour du prix du carbone à son prix d'équilibre de long terme. Les tests de sensibilité, en faisant varier ces deux paramètres, indiquent qu'il est très difficile de dévier du choix optimal de la calibration initiale (même avec une volatilité annualisée de l'ordre de 150% constante sur la durée de la modélisation et une vitesse de retour à la moyenne d'environ huit mois). Dans le cadre d'investissements, les marges de production du nouvel entrant, bien qu'affectées par ces prix du carbone erratiques, n'entraînent pas une modification du choix optimal d'investissement. Si l'on pousse le curseur un peu plus loin (volatilité supérieure à 150% et vitesse de retour à la moyenne de près de 3 ans), l'investissement dans les deux centrales CCGTs est retardé jusqu'à dix ans plus tard. Il s'agit d'un résultat typique de la littérature des options réelles. L'investissement dans les centrales éoliennes maritime n'est pas affecté. En poussant encore plus loin le curseur, le nouvel entrants se tournent exclusivement vers des technologies l'isolant du risque carbone (*carbon price hedge*), c'est à dire quatre parcs d'éoliennes maritimes ou une centrale nucléaire. Si les prix s'avèrent encore plus erratiques (volatilité de 300% et vitesse de retour à la moyenne supérieure à quatre ans), l'investissement dans la centrale nucléaire est décalé dans le temps (le nouvel entrant espère que l'incertitude sera résolue ou du moins réduite d'ici là) étant donné que la tendance pourrait se renverser. Au vu des valeurs extrêmes des paramètres, seul le cas de la calibration initiale semble raisonnable. De plus, les politiques de réduction de GES tendent davantage vers la stabilisation du paramètre de court terme (en améliorant l'efficience informationnelle des prix du carbone et la transparence du marché notamment).

Dans notre modèle, la dynamique de long terme est capturée par une forme linéaire composée d'un niveau (prix de départ du carbone) et d'une pente (interprétable comme un taux de croissance annuel du coût d'abattement du carbone constant sur la période de modélisation). Les variations autour de la calibration initiale (i.e. entre 10 et 50 euros la tonne d'ici 2030) indiquent que deux CCGTs et trois parcs d'éoliennes maritimes est le choix maximisant la valeur tirée de cette opportunité d'investissement. Si le prix de long terme du carbone devient trop élevé (au minimum 50 euros la tonne en 2030 - cas d'une forte pente positive pour la tendance de long terme), les CCGTs ne deviennent plus rentables et la nouvelle combinaison optimale pour le nouvel entrant est une centrale nucléaire dès t=0 (stratégie de couverture du risque carbone). En revanche, si le prix de long terme devenait plus faible (i.e. entre 0,10 et 10 euros la tonne d'ici 2030), la stratégie optimale du nouvel entrant serait d'investir prudemment dans des centrales à charbon sans CSC à la place des parcs d'éoliennes maritimes. Au cas où le prix de long terme s'effondrait (i.e. moins de 10 centimes d'euro la tonne d'ici 2030 - cas d'une forte pente négative pour la tendance de long terme), il n'est plus nécessaire d'attendre et le nouvel entrant investit dans deux CCGTs et trois centrales à charbon sans CSC dès t=0. Du point de vue des ajustements au SCEQE, le passage à un prix de long terme plus contraignant passe notamment par un mode d'allocation et un point de référence pour les allocations moins favorables aux installations, un taux d'effort de réduction plus important et moins de flexibilité avec les mécanismes de projets Kyoto.

Nous nous intéressons alors aux impacts des éléments hors prix du SCEQE sur les décisions d'investissement optimales du nouvel entrant. Nous rajoutons à la modélisation du prix du carbone un module permettant de capturer l'effet de l'ajout d'un prix plancher, d'un prix plafond, d'un tunnel de prix, d'une taxe remplaçant le SCEQE ou l'arrêt du SCEQE une année donnée. Nous trouvons que le nouvel entrant investit dans des centrales à charbon sans CSC à la place des éoliennes maritimes si le SCEQE est supprimé dès t=0 ou encore pour un prix plafond de moins de 6,6 euros en t=0. L'investissement dans les centrales à charbon peut être plus prudent et décalé jusqu'à dix ans plus tard pour un prix plafond de plus de 6,6 euros en t=0 (ou de 8,7 euros à la fin de la phase III) ou pour la suppression du SCEQE à la fin de la phase III. En revanche, pour un prix plancher de 49,5 euros en t=0 (ou de 76,2 euros à la fin de la phase III), le nouvel entrant se reporte sur une centrale nucléaire en t=0 afin de se couvrir du risque carbone.

Par ailleurs, nous trouvons que le SCEQE doit continuer sur une période d'au moins quinze ans pour avoir un effet sur les choix d'investissement d'un nouvel entrant. Si le SCEQE se termine en 2013, le choix optimal devient deux CCGTs et trois centrales à charbon sans CSC dès maintenant - en effet, plus qu'un prix du carbone, il s'agit d'une charge temporaire. Si le SCEQE se termine entre 2014 et 2026, le choix optimal devient deux CCGTs maintenant et trois centrales à charbon sans CSC plus tard en fonction de l'année d'arrêt du SCEQE (le plus proche de 2026, le plus tard) - les centrales à charbon attendant la fin du SCEQE pour être opérationnelles. Pour un arrêt au-delà de 2026, le cas initial reste optimal. Le SCEQE permet de mettre en réserve les quotas non utilisés les années antérieures. Entre la phase II et III de négoce, il est possible de mettre en réserve les quotas de phase II pour la phase III. Bien que la contrainte carbone soit fortement resserrée entre ces deux phases, l'existence de ce lien entre ces deux phases permet une continuité du prix entre le quota de phase II et celui de phase III. Nous avons testé l'effet de la suppression de ce lien intertemporel entre phase II et III dans l'hypothèse où la phase II soit sur-allouée au regard de la crise et que la Commission européenne souhaite que cela ne compromette pas les objectifs de phase III. Nous trouvons que si le nouvel entrant anticipe que le prix de phase II s'effondre en fin de phase II et reprenne aux alentours de 32 euros en début de phase III, alors il investira dans une centrale nucléaire dès maintenant. Enfin, nous avons testé différents niveaux d'allocation au titre de la réserve pour les nouveaux entrants mais aucun niveau même au cours de la phase III ne change la combinaison optimale d'investissement (la profitabilité est affectée mais pas au point de remettre en cause ce choix).

Le dernier groupe de tests de sensibilité porte sur les politiques de soutien direct à une technologies (renouvelables et CSC). Nous nous intéressons notamment à la durée et au niveau de soutien de ces instruments. Dans le cas de l'éolien maritime (tarif de rachat initialement de 130 euros le MWh pendant 10 ans puis de 64 euros le MWh pendant 10 ans), nous avons fait varier deux paramètres : la durée et le niveau du premier niveau de soutien. Nous trouvons que pour un soutien plus généreux que la calibration initiale (les dix premières années à 250 euros le MWh), le nouvel entrant investit dès maintenant dans quatre centrales éoliennes maritimes et utilise le budget restant pour une CCGT. A l'inverse, pour un niveau de soutien insuffisant (les dix premières années à 110 euros le MWh par exemple), les centrales éoliennes maritimes ne sont plus assez rentables et la combinaison optimale devient une centrale nucléaire maintenant (réduisant les tonnes de CO2 potentiellement émises sur la durée de vie des centrales). Ce résultat contre-intuitif est néanmoins mis en branle au cas où l'on considère une impossibilité à investir dans de nouvelles centrales nucléaires (cas allemand post-Fukushima). Dans ce cas, le nouvel entrant se reporte sur deux CCGTs et trois centrales à charbon sans CSC dès maintenant - soit une nette augmentation des tonnes de CO2 potentiellement émises sur la durée de vie des centrales par rapport au cas initial. Enfin, les tests sur le niveau de soutien minimal pour que les centrales à charbon avec CSC soient déployées estiment à 54% des coûts d'investissement le montant requis d'une dotation publique en capital.

Au-delà des cinq leçons à retenir (énoncées au début du résumé de ce chapitre), nous remarquons dans la conclusion que pour les questions d'investissement (1) les anticipations sur les politiques climatiques sont au moins aussi importantes que les politiques en cours ; et (2) des réponses originales et non anticipées sont à prévoir par les cibles de ces politiques.

Contents

List of Figures

List of Tables

List of abbreviations

AAU	Assigned Amount Unit
BAU	Business-as-usual
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CDM	Clean Development Mechanism
CER	Certified Emissions Reduction
CHP	Combined Heat and Power
CITL	Community Independent Transaction Log
DCF	Discounted Cash Flows
DDCF	Deterministic Discounted Cash Flows
EC	European Commission
ERU	Emissions Reduction Unit
EU ETS	European Union Emissions Trading Scheme
EUA	European Union Allowance
GBM	Geometric Brownian Motion
GHG	Greenhouse Gas
IEA	International Energy Agency
IGCC	Integrated Gasification Combined Cycle
IPCC	Intergovernmental Panel on Climate Change
JI	Joint Implementation
LSM	Least-Squares Monte Carlo
MACC	Marginal Abatement Cost Curve
NAP	National Allocation Plan
NER	New Entrants Reserve
NPV	Net Present Value
OLS	Ordinary Least-Squares
PDE	Partial Differential Equation
ROA	Real Options Analysis or Approach

Introduction

"However good our futures research may be, we shall never be able to escape from the ultimate dilemma that all our knowledge is about the past, and all our decisions are about the future."

Ian Wilson (1975)
Presentation to the American Association
for the Advancement of Science.

The quotation by Wilson about the general decision-making process particularly illustrates the difficulties of the investment decision-making process. Climate change represents an unprecedented challenge to all public and private decision-makers. However well we manage to forecast climate change impacts, by elaborating more detailed climate models, or the effects of climate policies, by improving our forecasting success, any forward-looking decision-making will ultimately rely on past information. The only way out is to acknowledge and embrace uncertainty in the investment decision-making. This PhD thesis explores the effects a major climate policy, the European Union Emissions Trading Scheme (EU ETS), has had and can have on investment decision-making.

The latest bodywork of the Intergovernmental Panel on Climate Change (IPCC) indicates that climate change has already started and the case for its anthropogenic origin is now strongly backed by the scientific community. The adoption in 1997 of the Kyoto Protocol, an international agreement aiming at fighting global warming, marks a milestone in policy-led mitigation efforts. The European Union is currently at the forefront of climate change mitigation policies. The EU, as a group, is among the largest emitters. In order to meet the Kyoto emissions reduction objectives of EU Member states, the individual countries created an EU-wide trading bubble and allocated a large part of their objectives to a cap-and-trade policy starting 2005: the European Union Emissions Trading Scheme (EU ETS). This EU flagship climate policy constrains some 12,000 carbon-emitting installations. The objective of such a policy is to foster cost-effective carbon emissions reductions among those installations.

In this dissertation, we propose an assessment of the impact the EU ETS has had on investments undertaken in the European power sector. The EU ETS is a multi-sector policy covering both the power & heat sector and industrial sectors (steel, cement, refining, etc.). We focus solely on European power generators mitigation investments because of the higher burden on this portion of installations - typically allocated less carbon allowances than expected emissions making them in net demand of carbon allowances. We chose to focus on corporate long-term decisions that have the potential to shape the carbon emissions structure of society the most (locking-in a given level of emissions potential). Following Dixit and Pindyck, we define investment as *"the act of incurring an immediate cost in the expectation of future reward"*[1]. When considering investing in carbon-abating opportunities when facing the EU ETS, firms will only decide to invest if future discounted benefits (GHGs abatement allowing a firm to sell carbon allowances or not having to acquire some of them) outweigh discounted costs (initial investment outlay and interim costs).

The analysis of the impacts of the EU ETS is interesting in several respects. First, the large scale and innovative nature of the EU ETS with new countries and sectors joining the scheme over time provides a very interesting policy setting to analyse. After all, this installation-level cap-and-trade policy is the first to involve that many countries. Second, the EU ETS is not an isolated climate policy as it is both the driving force behind the global carbon market and interconnected to other cap-and-trade markets via its influence on the pricing of Kyoto offsets. Third, assessments of the EU ETS indicate that there was an impact on emissions reductions albeit limited and rather catering to short-term impacts (changes in operating mode for flexible installations like fuel switching for instance). While it is desirable to trigger short-lived emissions reductions should the price of carbon go high enough, it is even more critical to trigger long-lived emissions reductions with investments that would "lock-in" lower emissions level. For the moment, the literature on those long-term induced effects is scarce given that the EU ETS was implemented only in 2004 and that data on corporate operating investments are far from being transparent and exhaustive. This PhD thesis aims at filling that gap and will focus on three main questions:

- How have European utilities coped with the EU ETS and was investment part of the response? If not, why so and what for instead?
- How has the EU ETS influenced the business-as-usual path of investments in the European power sector? What kind of investments were triggered? Have other factors played a more significant role?
- What are the specific pathways the EU ETS price signal take to influence investment decision-making? How to improve the EU flagship climate policy in this respect?

The main objective of this thesis is to come up with a better understanding of the EU ETS impact on power generation investment and fill the corresponding literature gap. We make the following assumptions which remain to be verified by the empirical data we collect and by a real options investment model we built for the occasion. First, the price of carbon might not be enough to give an incentive for investment in low-carbon / carbon-free generation units and could even delay such investments due to regulatory uncertainty. Second, investment in CCS is subject to bargaining direct support from the EC or EU Member states and the price of carbon might not play the support role it is supposed to. Third, investments in renewables is a direct response to renewable policies and it is unclear to what extent carbon markets are helping or distorting the incentive (and conversely, to what extent technology-dedicated incentives support or distort the EU ETS policy). Our chief focus is to what extent carbon prices direct and have directed investments towards specific low-carbon technologies.

The PhD thesis is organized in three main chapters. First, we look at the EU ETS in great details to understand how it might have impacted European utilities and how they actually coped with the newly introduced carbon constraint (chapter 1). To better understand whether the EU ETS actually gave the incentive to invest in low carbon technologies, we tackle the issue using two complementary approaches. First, we compiled and analysed six years of European utilities' financial statements and corporate communications for the top 5 most carbon constrained utilities in order to reconstitute the evolution of the power plant investment pipeline (chapter 2). Second, we resorted to a model based on the real options approach in order to grasp the impact of an uncertain carbon price on corporate investment decisions using scenarios (chapter 3).

In the first chapter of the thesis (*"European utilities' response to the European Union Emissions Trading Scheme"*), we focus on the newly introduced EU ETS climate policy, some other determining factors for investment in generation (technology-specific incentives and the impact of the financial and economic crisis) and the responses deployed by European utilities to deal with the EU ETS. The aim of this chapter is to provide both background information on the EU ETS and gain insights on how the price signal sent by the EU ETS affected decision-making in the European power sector. For the policy review, we mostly resorted to the academic literature, official releases from the European Commission and Member states and market analyses from carbon market research groups. For the European utilities responses, in addition to this, we used elements from the corporate literature (financial statements, corporate communications, etc.). We discuss how the EU ETS was introduced and how the constraint was gradually increased for compliance buyers. We highlight that European utilities benefited from transitory measures and some provisions to accommodate that constraint with the use of offsets or the ability to bank carbon allowances from one year to another. Since the beginning of the EU ETS, the work-in-progress status of the market (giving rise to much uncertainty) and low ambition of the first years partially explain the low level of investment in low carbon generation attributable to the EU ETS. Alternatively, European utilities have been active on the carbon compliance asset procurement side and on developing hybrid or outside-the-box responses (lobbying and carbon asset provisions in long-term contracts). The main difficulty encountered in this chapter was to identify which corporate responses were disclosed by utilities (on a voluntary or mandatory basis) and which were not. In addition to this, there were some difficulties in going beyond some nice corporate communications exercises to get to specifics. In this chapter, we gain insights into expected and unexpected policy impacts and provide the foundations for analyses dedicated to investment decision-making in chapter 2 and 3.

In the second chapter (*"Operating and financial investments by European utilities over 2004-2009: what role for climate policies?"*), we explore in greater details past and projected investments by European utilities. We aim at filling the gap in the literature on the impact of the EU ETS on compliance buyers by looking at the empirical data on investment for European utilities. We focus on the top five most carbon constrained European utilities (E.ON, RWE, Vattenfall, EDF and Enel) and consider both investment in power generation (greenfield and brownfield investment and divestment as well) and financial stakes taken in the power generation business (expecting to be able to capture a large chunk of the repositioning of European utilities towards a cleaner electricity generation mix). The main difficulty encountered in doing this type of exercise is the lack of transparent, detailed and readily available data on corporate investment. In order to proceed with the analysis, we manually collected data from several official corporate sources on investment by these five European energy groups over the 2004-2009 period. We were able to reconstitute the realised and projected pipelines of investments and participations by these utilities. We found that in the early years, strategic repositioning considerations prevailed (towards a regional energy group positioning). One of the difficulties encountered was the absence of a consensual counterfactual investment scenario over the corresponding period. Therefore, we have only been able to highlight that some investments were in favour of carbon emissions reduction without being able to attribute this to the ETS directly but rather to the mix of applicable climate and non-climate policies. With the beginning of a tighter constraint in phase II (2008-2012) and expectations regarding phase III constraint, more investment-related responses were triggered. Nonetheless, we find that some of the responses were rather creative requiring further monitoring, in particular when there is a risk of carbon leakage or when commissioning of required generation capacity is unduly postponed.

After having discussed the decision-making environment and corporate responses (chapter 1) and an empirical account of operating and financial investment (chapter 2), we explore a more theoretical point of view on investment in the third chapter (*"Impact of the EU ETS on investment in new generation: a real options approach"*). We present the evolution of investment decision-making models and explain the difficulties but also the benefits of resorting to a real options approach compared to a traditional deterministic discounted cash flows models. This chapter aims at developing carbon price scenarios and analysing their impacts on power generation investment portfolios. In order to do so, we resort to a real options setting using the least-squares Monte Carlo approach (Longstaff and Schwartz, 2001 [2] and Gamba, 2003 [3]). The investment decision model used is able to consider various generation technologies and several sources of uncertainty (including the carbon price). The model allows for flexibility in the decision-making under some budget constraint. Results from sensitivity tests to various carbon price scenarios indicate that (1) the EU ETS has a moderate but central reallocation role in power generation investment portfolios, (2) insights into the long-term carbon price trend, especially the level of the cap at various points in time, are particularly helpful to unlock investment in generation, (3) some much discussed policy provisions (price support mechanisms or the new entrants reserve for instance) only have a relatively small or negligible impact on power generation investment portfolios, (4) carbon price expectations impact decisions relative to power generation investment portfolios including delays and cancellations and (5) while the EU ETS has a central role, the climate and non-climate policy mix matters most. The model developed in this chapter is able to capture both timing and technology changes in a portfolio context and provide some insights to policymakers in designing and making amendments to cap-and-trade policies with a view towards more emissions reduction by compliance buyers.

The main difficulties we faced in this PhD thesis were, first, the absence of a readily available dataset for investment in power generation in Europe and, second, some methodological difficulties in developing a relevant and insightful decision-making model. The former was addressed by manually reconstituting the power generation investment pipeline of the surveyed utilities. The latter was addressed by resorting to a state of the art real options model.

Chapter 1

European utilities' response to the European Union Emissions Trading Scheme

The entry into force of the European Union Emissions Trading Scheme (EU ETS) in 2005 was a milestone for climate policies. Never before has a single market-based instrument been applied to so many industrial installations in a relatively successful manner. In this chapter, we define and analyse the climate policy framework and economic conditions in which European utilities made investment decisions since 2005. In many respects, the European power sector has been affected by the introduction of the EU's flagship climate policy. We discuss in great details the EU ETS various transformations and European power sector responses to it.

First, we discuss the policies affecting the way climate is tackled in the EU at both the Community and the member state levels. We thoroughly explore the design of the EU ETS over the three trading phases and their actual and likely impacts on European utilities decision-making. Second, over the last few years, other major economic and policy developments affected decision-making in the European power sector. We focus on two of the most relevant developments to understand the questions of investment: (1) European and national generation technology-focused incentives and (2) the economic and financial crisis that started in 2008. Third, focusing on the backbone of European climate change policies, we explore how carbon-constrained utilities can deal (and have dealt) with the EU ETS. The spectrum of action for European utilities ranges from short-term operational changes or carbon trading decisions to long-term investment decision-making to reduce emissions levels.

1.1 GHG mitigation policies targeting European utilities

In this section, we discuss the climate policies in the field of GHG mitigation targeting the European power sector. We begin by discussing the global climate policy context and then jump into the specifics of the EU ETS: genesis, trial phase, Kyoto phase and post-Kyoto phase.

1.1.1 Climate change policy context

The Intergovernmental Panel on Climate Change (IPCC), a joint UN-WMO scientific body, was established in 1988 to evaluate the threat of climate change. IPCC's four assessment reports (1990, 1995, 2001 and 2007) established the need to reduce GHG emissions if humanity is to avoid any strong adverse impacts of climate change. The conclusions of the latest bodywork of the IPCC are unequivocal: climate change has already started and its anthropogenic origin is now widely accepted. The international scientific community is particularly worried about forthcoming manifestations of climate change.

Adopted in late 1997, the Kyoto Protocol is an international agreement aiming at fighting global warming. It entered into force in 2005. Simply stated, the Kyoto Protocol splits the international community into two groups of countries. On the one hand, there are the so-called "Annex I countries" which are the historical emitters of GHGs. These 37 industrialized countries pledged to an average emissions reduction of six GHGs[1] by 5.2% from the 1990 baseline year. On the other hand, the "non-annex I countries", low income countries, are not bound by such emissions reduction effort. To facilitate the emissions reduction process, the Kyoto Protocol has given Annex I signatory states three "flexible mechanisms" to curb their GHGs emissions.

First, **international emissions trading** is a state-level cap-and-trade mechanism. The individual state-level emissions reduction objectives (from the 5.2% overall reduction) correspond to capped annual emissions levels in tons of CO2-equivalent (CO2e). A GHGs emissions rights called an Assigned Amount Unit (AAU) is assigned to each ton of CO2e. The international emissions trading allows Annex I countries to trade AAUs among them. Countries engage in trading so that emissions reductions are first achieved in countries where the cost of abatement are the lowest. Therefore, emitting countries for whom it is less costly to achieve emissions reduction would curb emissions beyond their cap, and trade the thereby obtained excess AAUs with countries where it is more expensive to reduce GHG emissions. Likewise, countries for whom it is expected to be expensive to reduce emissions would resort to this flexibility mechanism to reduce the cost of achieving their Kyoto target.

Second, the **clean development mechanism** (CDM) is an offset mech-

[1]Carbon dioxide (CO2), methane (CH4), nitrous oxide (N2O), sulphur hexafluoride (SF6), hydrofluorocarbons (HFCs) and perfluorocarbons (PFCs).

anism allowing annex I countries to invest in emissions reduction projects hosted by annex B countries. The CDM is all about the "production" of emissions reductions. Again, the idea behind is to perform the emissions reduction where they are the cheapest. The production of emissions reductions occurs when an emissions reduction project is undertaken in an eligible annex B country and emissions reductions against a project-specific baseline are verified by an UN-accredited entity. The project is to be deemed "additional" in the eyes of the UN to be eligible to CDM - that is to say that the project would have not been undertaken in the absence of this flexible mechanism. The investor undertaking the CDM project is entitled a Certified Emissions Reduction (CER) for each ton of CO2e abated in excess of the baseline. CERs can be then be used for Kyoto compliance in lieu of AAUs. CDM projects span to a wide range of emissions reduction solutions: deployment of renewables, changes brought to industrial processes, afforestation and reforestation projects, etc.

Quite similar to the CDM, the **joint implementation** (JI) is an offset mechanism allowing annex I countries to invest in emissions reduction projects this time hosted by annex I countries. Contrary to the CDM, the Emissions Reduction Units (ERUs) obtained with JI against verified emissions reductions beyond a baseline are deducted from the host country's supply of AAUs. There is no creation of ERUs as is the case for CERs. Even though they constitute emissions reductions compared to a baseline, it should be stressed that CDM and JI projects can still be GHG-emitting projects. The logic behind the conversion of AAUs into ERUs is to prevent Annex I countries with binding Kyoto targets to undertake major projects among them that would implicitly prevent them from achieving their Kyoto target.

EU ETS design phase

In 1998, under the European burden sharing agreement, Kyoto-constrained EU member states have created a trading bubble gathering CO2-emitting installations in certain sectors (power and heat generation industry, combustion plants, oil refineries, etc.) across the EU. The European Union Emission Trading Scheme (EU ETS) was launched in 2005 to facilitate European member states compliance with the Kyoto protocol. The EU ETS allows CO2-emitting installations to reduce emissions by means of a cap-and-trade initiative in a similar fashion to Signatory States under the Kyoto Protocol. While the scope of the Kyoto Protocol is multi-GHG and spanning to almost every sector of the economy, the EU ETS specifically targets carbon dioxide emissions from stationary sources of emissions (combustion installations above 20 MW) and shifts *de facto* a large share of the Kyoto environmental burden of EU member states to these EU stationary sources.

The EU ETS is a cap-and-trade policy. A cap-and-trade scheme gives the incentive to reduce emissions beyond the cap since compliance-buyers are allowed to sell emissions rights in excess of their emissions needs to those for whom it is more expensive to reduce their emissions on their own. The asset traded is the European Union Allowance (EUA) which gives the right for its EU ETS holder to emit one ton of CO2 in the atmosphere. To claim compliance, EU ETS installations must surrender as many EUAs as tons of CO2 they have emitted over a given year. They can do so by either acquiring more EUAs (or similar assets) or by reducing their emissions. The need for trading happens because of the pre-established scarcity of emissions rights over a given period of time - the cap suggested by European member states and accepted by the EC. The allocation of allowances in the EU ETS among the trading sectors recognizes different sectoral abatement options and related costs as well as impacts on competitiveness.

At the time of writing, there were three compliance periods in the EU ETS: the trial phase (phase I) between 2005 and 2007, the Kyoto phase (phase II) between 2008 and 2012 and the post-Kyoto phase (phase III) between 2013 and 2020. The trial-and-error policy process brought many changes and adjustments to the policy over these three phases.

1.1.2 EU ETS Phase I: a trial phase

The *modus operandi* common to phase I and II of the EU ETS is the following. EU member states identify the installations falling within the scope of the directive: stationary sources of carbon dioxide (CO2) emissions with a capacity above 20 MW. EU member states then enter in consultation with the owners of the regulated installations to obtain historical emissions data or attempt to do so based on various estimation approaches. Each member state applies its effort share of the burden sharing agreement to its national emissions cap and distributes this burden among the installations. As a result, an emissions cap, corresponding to the maximum quantity of CO2 an installation can emit during a given period, is set. The next step involves drafting a document called a national allocation plan (NAP in short). This document summarises elements from the whole process and ultimately outlines the overall national emissions cap and each installation's emissions cap over an entire market phase. The NAP is then communicated to the EC. The EC reviews the submission to ensure that (1) the member state is on the right track to meet its emissions reduction objective and (2) that ultimately the EU is expected to claim compliance towards Kyoto.

Stationary sources falling within the **scope** of the Directive are combustion installations with an installed capacity superior to 20 MW. Some 70% of those installations are either producing power or heat and it was estimated that 49% of them where solely producing power (Trotignon and Delbosc, 2008 [4]). The remaining installations are industrial installations from the steel, cement, refining sectors among others. Installations within the scope of the Directive have been entitled European Union Allowances (EUAs). An EUA is the right to emit one ton of CO2 during a specific time period. The quantity of EUAs they have been entitled corresponds to the emissions cap applying to them. While, on average, the industrial installations have been allocated more allowances than required over the compliance periods, the power and heat portion of the EU ETS was entitled less EUAs than was expected to be needed. Emissions reductions in the power sector can be achieved by means of short-term operational adjustments (like fuel switching to a lower carbon content combustion fuel), investments in less carbon-emitting technologies (retrofitting power plants with carbon capture and storage or investing in a plant that emit less based on its initial characteristics) or by halting or decreasing the power plant output (and the emissions consequently). Financial intermediaries (by extension, anyone undertaking the account and registry opening processes) can also participate in the scheme thereby bringing liquidity to the market.

The prevailing **allocation method** during phase I and II was grandfathering. EU ETS installations emissions cap was fixed based on historical emissions. During the first two compliance periods, allowances were mostly allocated for free. In order not to disadvantage new entrants (genuine new entrants in the European CO2-emitting sectors or extra combustion units from incumbents that would fall within the scope of the Directive), a new entrant reserve (NER) was negotiated and set aside. This NER is comprised of free allowances provided to new installations so that incumbents would not be favoured as regards the EU ETS.

Regarding the beginning of operations, the EU ETS was full-fledged later than expected. As late as in the second quarter of 2006, many European countries were still not ready for the EU ETS. In particular, several registries for allowances were still not connected to the Community Internal Transaction Log (CITL, the database used to surrender allowances for compliance). This prevented surrendered allowances to be transferred for compliance purpose. Moreover, some NAPs for phase I were still in early draft status, some member states organised late distribution of allowances to installations thereby impeding any trading activity, etc.

In April-May 2006, the market experienced its first major **informational shock** with the early release of the emissions data of some major member states for the year 2005 ahead of the annual ”true-up” event. While, prior to this event, the belief that European installations were under-allocated free allowances was shared among market operators, the early release hinted at a largely over-allocated market. The over-supply of allowances compared to demand triggered a strong price correction (phase I price decreased by 64% between April 24th and May 2nd). On May 15th, the official release by the EC of aggregated emissions for the year 2005 did little to dissipate doubts over too large an emissions cap for Phase I. In April 2007 and 2008, the process was smoother and more streamlined to prevent similar major impact on market prices. The fact that market participants had no expectations of scenario reversal during phase I also helped.

As regards the **use of Kyoto offsets** in phase I of the European scheme, the European so-called "linking directive" (which was adopted in 2004) permits the use of CDM offsets for compliance purpose. The use in phase I is theoretically unrestricted (i.e. compliance could be achieved by surrendering solely Kyoto offsets). Nevertheless, this was prevented by (1) the long wait to have the ITL (Kyoto registry) operational (which only happened in late 2007), (2) the practical constraint to have the CITL (EU ETS registry) connected to the ITL. Initially scheduled for April 2007 (Alberola and de Dominicis, 2006 [5]), the connection was delayed to October 2007 and then to December 2007[2]. Afterwards it was obvious that no CERs would be available for use in the EU ETS during phase I.

Banking opportunities for unused allowances from phase I to II, initially very limited to France and Poland only, were rendered unattractive by EC decisions on several NAPs for phase II in October-November 2006. In short, any allowance carried forward to phase II would decrease the member state's corresponding NAP II emissions cap. This triggered a price disconnect between phase I EUA price and that of phase II. The idea behind this EC move was to prevent that phase I excess allowances would be carried forward towards phase II which would have undermined the constraint of the scheme.

Figure 1.1 depicts the evolution of the price of the Phase I EUA over its lifetime. We see the price shock that occurred during the first "true-up" event and the price disconnect that ensued. Nevertheless, apart from those major price shocks, the price of the EUA responded to market fundamentals, that is information regarding the supply of allowances (NAPs) and demand for emissions (industrial activity, the relative price of gas and coal, temperature and precipitation data, etc.).

[2] According to the UNFCCC secretariat (reported in Tendances Carbone, 2007, [6]).

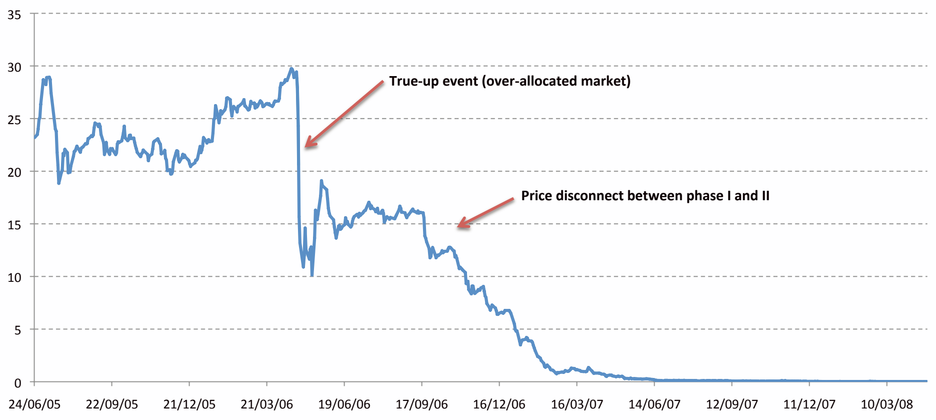

Figure 1.1: Phase I EUA historical price in EUR per ton - Bluenext data

1.1.3 EU ETS Phase II: the Kyoto phase

For the second trading period (2008-2012), while the approach remained the same, the EC attempted to correct some of the flaws of the first trading period. Furthermore, the Kyoto phase introduced the use of Kyoto credits.

The shift to phase II marked several changes in the **scope** of the policy. First, additional gases began to be included within the scope of the ETS (voluntary inclusion of N2O-emitting installations in France for instance). Second, additional countries participated in the scheme (Norway joining along the way and Bulgaria and Romania participating to an entire trading phase). Third, plans regarding the inclusion of additional trading sectors progressively into the European scheme (aviation in particular) became more precise.

As regards the **NAP submission, review and validation process** between member states and the EC, negotiations were more difficult with the passage to the second trading phase. The NAPs for phase II (NAP II for short) were initially scheduled for submission to the EC by June 30th, 2006. Nevertheless, NAP II initial submissions have been delayed for most member states. The NAPs were often either in national public consultation phases or still in the initial drafting process. Three months past the deadline, only 14 member states had submitted their plans. In addition to the delays at the initial draft, there was additional delays in the final validation of the NAPs for phase II (both on the EC and member states sides). This caused further impediments to the distribution to individual installations[3]. Later by mid-

[3] With less than 3% of allowances distributed to installations by the end of February 2008 deadline.

2008, another reason invoked[4] not to distribute allowances to installations was the fact that the CITL and ITL were not yet connected. The year after, only 23 out of the 30 countries participating in the EU ETS issued their 2010 allowances to their installations prior to the February, 28th deadline (accounting for 78% of the total cap). The main reason for those delays was legal challenges of NAP revisions by the EC[5].

Submitted NAPs have been evaluated on the basis of several criteria by the EC including the stringency of their emissions caps and related parameters (use of offsets, auctioning of allowances, etc.), projected emissions trends and emissions reduction potential. This has been performed with the achievement of the Kyoto targets in mind (ETS sectors and non-ETS sectors) - namely, too high a cap might prevent reaching those targets. The EC had three months to evaluate submitted plans. On average, Western European countries have slightly reduced the emissions cap compared to phase I in comparison to Eastern European countries' NAP II drafts who attempted to increase the cap between the two phases for an identical installations' perimeter[6].

Initial draft allocations submitted by member states were mostly slashed by the EC both regarding too high a cap and too large the share of compliance which could be achieved with Kyoto offsets. For instance in November 2006, the first ten draft emissions cap levels reviewed (including Germany and Eastern European countries) were severely cut by the EC (minus 7%, i.e. 63.9 MtCO2) and Ireland's initial plan to use up to 50% of Kyoto offsets for compliance with the EU ETS was reduced to 21%[7]. Early estimates for phase II cap indicated that circa 2,081 MtCO2e would be allocated on average per annum between 2008 and 2012 which is 10.5% less than initially planned by member states in their earlier drafts and 9.5% less than in the first phase[8].

In early 2007, the first complaints towards the EC regarding NAPs reviews were addressed. Many voices were raised against slashed NAPs but only a few countries (Eastern Europe countries mostly) actually proceeded to legally challenge the EC as regards revised allocation plans. In January 2007, Slovakia first announced its intention to legally challenge the EC. In April 2007, Poland, the Czech Republic, Slovakia and Hungary had filed an appeal against the EC with the European Court of Justice. These appeals were motivated on grounds that the revised allocations (1) prevented

[4] By the UK and Ireland to be more specific.
[5] Tendances Carbone (2010, [7])
[6] Tendances Carbone (2006, [8])
[7] Tendances Carbone (2006, [9])
[8] Tendances Carbone (2007, [10])

the countries' full economic development and (2) were discriminatory as they prevented to catch up with Western European countries[9]. The picture changed in the fourth quarter of 2009 when the European Court of First Instance overruled the EC's decision on Estonia and Poland NAPs for phase II. In December 2009, the EC appealed this ruling while continuing to negotiate with these member states so as to define new emissions caps based on the best available emissions data over the reference period. Later in December, the EC formally rejected the NAP II of those countries justifying its position by claiming that the caps were too high.

As regards **flexibility mechanisms**, the use of Kyoto offsets for EU ETS compliance in phase II is allowed by the linking directive but restricted to specific percentages of surrendered carbon assets as set forward in the NAPs. In phase II, allowed offsets extends to ERUs. The restrictions depend on the member states and sometimes on the sector. The average authorised use is 13.5% with a range between 0% for Estonia and 20% for Germany and Spain. In August 2008, the EC announced that it successfully tested the connection between the ITL and the CITL and that both registries would be officially connected from October 2008. The official connection in October led major member states to finally issues their 2008 allowances.

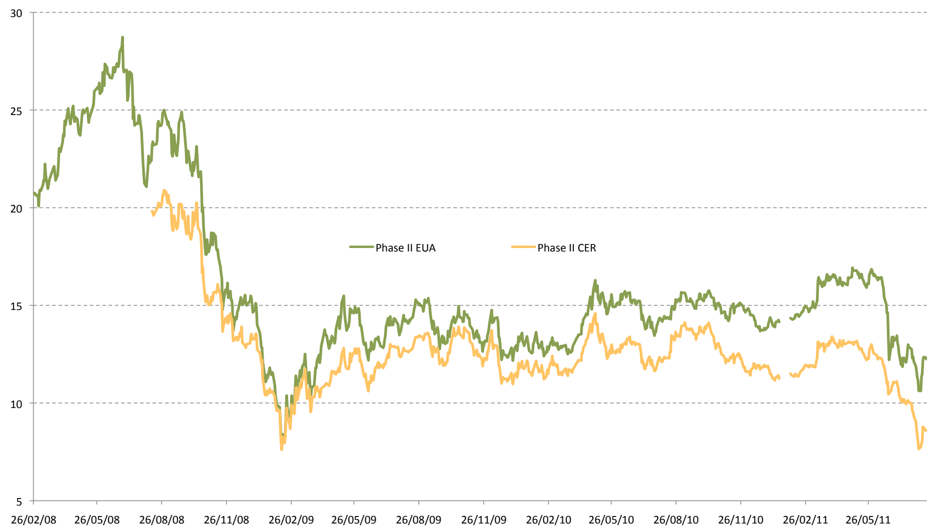

Figure 1.2: Phase II EUA and secondary CER historical prices in EUR per ton - Bluenext data

Figure 1.2 depicts the evolution of phase II prices, both carbon allowances (in green) and secondary certified emissions reductions (sCERs in orange).

[9]Tendances Carbone (2007, [11])

We observe that the carbon allowance price responded to the typical market fundamentals that were valid during phase I. In addition to this, the price of EUAs was evidently influenced by any major announcement related to phase II emissions cap (NAP submissions, reviews, validations and legal challenges notably) and intertemporal flexibility with phase III of the scheme. Secondary CER traded at a discount to EUAs. The price differential between the two compliance assets reflects the limitations imposed on the use of this flexibility mechanism for EU ETS compliance buyers and some opportunistic trades on the part of the largest players on the market (Mansanet-Bataller et al., 2011 [12]).

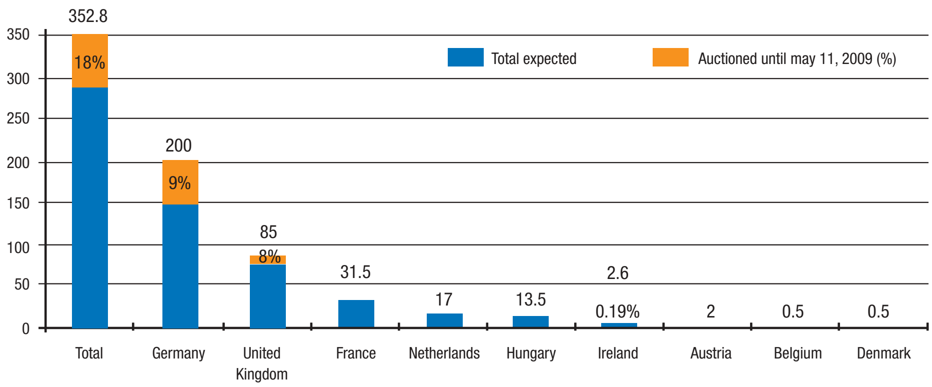

Figure 1.3: Volume of allowance auctioning during Phase II in Mt - from Caisse des Dépôts Tendances Carbone 36

Phase II was also marked by a larger proportion of **auctioning** of allowances than in phase I. Figure 1.3, reproduced from Tendances Carbone no. 36 and based on EC data, illustrates this tendency. This increased the overall constraint as a larger proportion of allowances was to be acquired rather than allocated for free. This generated extra revenues for members states organising auctions. In addition to this, the level of the new entrants reserves is varying between member states depending on member states and ultimately on additional installations that would be included in the scope of the EU ETS during the course of phase II. Finally, in phase II, new parameters in draft and revised NAP were introduced: benchmarking system for the energy sector in the revised German NAP for phase II, etc. Table 1.4 summarises the key data on phase II NAPs as of early 2010 (based on CDC Climat Research, EC and NAP)[10].

[10]* There is no new entrants reserve in the Norwegian NAP. ** The 12 Icelandic installations falling within the scope of the Directive have been excluded as they are already subject to more constraining emissions reduction measures.

Countries	Allocation phase I in Mt (Incl. NER)	Allocation phase II in Mt (Incl. NER)	Change in allocation between Phase I and II	Opt-in Phase II (in Mt)	Auctioning (in Mt)	Kyoto credits import limit (in %)
Germany	499.0	451.9	- 9.4%	11.0	39.8	20 %
United Kingdom	245.3	245.6	+ 0.1%	9.5	17.2	8 %
Poland	239.1	208.5	- 12.8%	6.3	-	10 %
Italy	223.1	201.6	- 9.6%	-	-	15 %
Spain	175.3	152.3	- 13.2%	6.7	-	20 %
France	156.5	132.8	- 15.1%	5.2	6.3	13.5 %
Czech Republic	97.6	86.8	- 10.8%	-	-	10 %
Netherlands	88.9	85.8	- 3.5%	4.0	3.4	10 %
Romania	74.8	75.9	+ 1.5%	-	-	10 %
Greece	74.4	69.1	- 7.1%	-	-	9 %
Belgium	62.1	58.5	- 5.8%	5.0	0.1	12 %
Bulgaria	42.3	42.3	+ 0.0%	-	-	12.6 %
Finland	45.5	37.6	- 17.4%	0.4	-	10 %
Portugal	38.2	34.8	- 8.9%	0.8	-	10 %
Slovakia	30.4	32.6	+ 7.2%	1.8	-	7 %
Austria	33.0	30.7	- 7.0%	0.4	0.4	10 %
Hungary	31.3	26.9	- 14.9%	1.4	1.3	10 %
Denmark	33.5	24.5	- 26.9%	-	0.1	17 %
Sweden	23.2	22.8	- 1.7%	2.0	-	10 %
Ireland	22.3	22.3	+ 0.0%	-	0.1	10 %
Estonia	19.0	12.7	- 33.1%	0.3	-	0 %
Lithuania	12.3	8.8	- 28.5%	0.1	-	20 %
Slovenia	8.8	8.3	- 5.7%	-	-	15.8 %
Cyprus	5.7	5.5	- 3.9%	-	-	10 %
Latvia	4.6	3.4	- 25.4%	-	-	10 %
Luxemburg	3.4	2.5	- 26.5%	-	-	10 %
Malta	2.9	2.1	- 26.2%	-	-	Unknown
Total EU 27	2,292.5	2,086.7	- 9.0%	54.8	68.7	13.5 %
Norway	-	15.0*	-	-	7.5	20 %
Liechtenstein	-	0.02	-	-	-	8 %
Iceland**	-	-	-	-	-	-
Total EU 27 & EFTA	-	2,101.6	-	-	76.2	13.5 %

Figure 1.4: Phase II National Allocation Plans - as of February 2010

1.1.4 EU ETS Phase III: towards more constraint

Phase III of the EU ETS starts in 2013. This new trading phase will be a direct continuation of the EU ETS with nonetheless several marked changes in both the fundamental design of the policy and specific details of related provisions.

Policymakers eager to promote a more efficient policy made the case that a shift from a bottom-up process (where there is consultation between compliance-bound participants and member states and then between member states and the EC to decide on the level of the cap) to a top-down process (where the EC decides on the cap and this cap is then scaled down at member state-level and installation-level) would benefit EU member states willing to meet their emissions reduction targets.

The most significant change is the shift away from a cap-and-trade scheme based on the free allocation of grandfathered allowances to a scheme chiefly based on the auctioning of allowances. The transitional element of policy design to help compliance buyers swallow the pill will therefore be removed annunciating a heightened constraint.

The initial proposal On 23rd of January 2008, the EC presented its amended draft directive for the post-2012 period (presenting other elements of the so-called "energy-climate package"). Table 1.5, reproduced from Tendances Carbone no. 22, is based on NAP I and II and EC COM (2008) 16 final and illustrates the major changes compared to the previous market phases.

	2008-2012	Proposals over 2013-2020	
		Without international agreement	With international agreement
Allocation cap	**NAPs** proposed by Member States and validated by the European Commission Fixed cap over the period	**European-wide cap,** split among States according to their emissions and economic situation. Declining cap over the period.	
		By 2020, −21% compared to 2005 emissions level	By 2020, about −30% compared to 2005 emissions level
Allocation methodology	Member States can auction up to 10% of allowances	100% of auctioning in the power sector from 2013 on. Progressive auctioning (20% in 2013; 100% in 2020) for the remaining sectors.	
		Option to continue free allowance allocation to those sectors affected by carbon leakage	
Use of Kyoto credits	Allowed up to 20% of the allocation cap	2008-2012 surplus	
			50% of the additional emissions reduction effort

Figure 1.5: EU ETS Directive modification proposal - from Caisse des Dépôts Tendances Carbone 22

The major changes brought to the policy design are:

- The shift from a bottom-up allocation method with free allowances to a **centralised top-down process with auctioning of allowances**. This change was required to establish a stronger constraint on carbon-emitting installations and to put an end to the negotiating process over NAPs.

- The ability to step-up the constraint on emissions from -21% to -30% over phase III depending on the outcome of the negotiations for the post-Kyoto agreement (Copenhagen) which clearly was a diplomatic tool sending the signal that the EC would only do more if other countries also made significant commitments. Later on, such discussions continued at the EU level irrespective of the outcome of the negotiations.

- Similarly regarding Kyoto offsets, the EC recognizes carbon offsets as eligible assets for compliance with the EU ETS beyond 2012. At the same time, the message sent to the international community is that the EU won't sustain the development of the CDM all by itself. The most satisfactory the post-Kyoto agreement, the larger the quantity of Kyoto offsets able to enter the EU ETS and in the end the larger the number of emissions reduction projects in place in developing countries.

Related debates Additional issues to be considered with this evolution included (1) the sharing of revenues from auctions proceeds among the EC and member states and ultimately final uses of this money in the economy and (2) the auctioning (i.e. entailing a greater constraint) of allowances to sectors deemed most exposed to international or at least non carbon-constrained competition could suffer from competitiveness loss and carbon leakage. Clearly, the release of the draft directive triggered concerns of losses of competitiveness and carbon leakage on the one hand and objections to the full auctioning of allowances for the power sector (Czech Republic and Poland) on the other hand. Over time, restrictions on Kyoto credit imports for compliance purpose were added to the list of concerns.

In March 2008, the Council of Europe affirmed its intention to have the "energy-climate package" ratified by the end of 2008. The Council of Europe also asked for an analysis of industrial sector claims of potential carbon leakage and potential remedies in the form of allowances granted for free or other adjustment mechanisms. In September 2008, the Industry Committee of the European Parliament suggested amendments to the initial proposal to limit the extent of adverse impacts to the industrial sector competitiveness. Among the potential measures were impact assessment studies before committing to any unilateral post-Kyoto commitment, increase of the CER import limit to 25% of the Phase III emissions reduction and a larger allocation to energy-intensive industries[11]. In October 2008, the Environment Committee of the European Parliament voted changes to the initial proposal. At this point, the European Parliament entered into negotiations with the EU council and the EC so that the Energy-Climate package would become a law. On the agenda of these negotiations was (1) the use of offset credits, (2) the percentage of allowances granted for free to industries exposed to international competition from 85% in 2013 to none in 2020, (3) the full auctioning of allowances to power and heat generation to the exception of district heating and CHP, (4) the possibility to grant up to 500 million allowances to finance a dozen of CCS demonstration plants and (5) a 500 g/kWh CO2 emissions limit for new power plants with installed capacity above 300 MW from 2015 (which would mean no coal- or lignite-fired plants without CCS)[12]. The last batch of suggested amendments was not to the taste of several member states. In November 2008, Poland, Italy and seven new member states called for higher emissions caps and a phased-in auctioning to the power sector[13]. France, then heading the EU presidency, suggested several measures to compromise during the EU summit. These included (1) the introduction of "market management measures" to prevent an excess volatility of carbon allowances prices and (2) a phased-in auctioning for the power sector depending on member states' power generation mixes and interconnection to the network of European power grids. Meanwhile, the negotiations between the European Parliament, the EC and the EU Council continued.

Adoption of the package On December 17th, 2008, the European Parliament approved the draft Directive for Phase III of the EU ETS. Overall, the text approved was quite similar to the initial proposal of January (including the emissions cap) to the exception of (1) a **scheduled phased-in auctioning for the power sector** from 30% in 2013 to 100% in 2020 and (2) a phased-in auctioning for other sectors from 20% in 2013 to 70% in 2020. Regarding this second element, there is a system of benchmarks that would allow to obtain allowances free of charge[14] for the industrial installations deemed to be most exposed to competitiveness losses and exposure to carbon leakage. In April 2009, the revised ETS Directive in the Energy-Climate Package was formally adopted by the EU Council. In July 2010, the European Commission announced a 2013 quota ceiling of 1,927 MtCO2

[11] Tendances Carbone (2008, [13])
[12] Tendances Carbone (2008, [14])
[13] Tendances Carbone (2008, [15])
[14] Tendances Carbone (2009, [16])

for Phase III of the EU ETS, calculated based on a reduction coefficient of 1.74% per year until 2025. It will be revised to include new sectors, entrants and gases, and for any decision to change the emission reduction target from 20% to 30%[15].

Comitology process While the big picture for phase III is quite clear, negotiations on the very details of the scheme were (and some still are) discussed in a comitology process, whereby the EC undertakes consultation on the implementation of the Directive via comitology committees. Figure 1.6, reproduced from Tendances Carbone no. 34 ([18]), summarises the calendar for the comitology process in the EC as of early 2009.

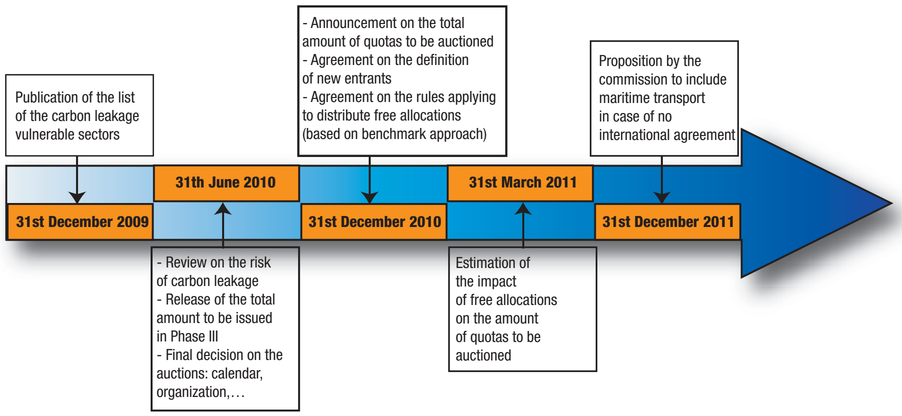

Figure 1.6: Calendar for the comitology process - from Caisse des Dépôts Tendances Carbone 34

The first step in this comitology process was the definition of the **sectors most exposed to carbon leakage**. The award of 100% of allowances free of charge, at the level of the benchmark, to installations deemed most exposed to carbon leakage obviously benefits recipients and therefore required some justification. In April 2009, the DG Enterprise of the EC applied a set of criteria to 258 sectors. What would be the likely impact of auctioning on the sector's production costs? And how exposed is the sector to extra-European competition? A provisional list of sectors was prepared at the end of this process. In September 2009, the member states agreed upon this provisional list of industrial activities exposed to international competition (164 sectors in total).

In order to avoid carbon leakage in the most vulnerable industrial sectors, a benchmark system had been suggested to allocate allowances free of charge

[15] Tendances Carbone (2010, [17])

to such aforementioned sectors. Another related critical step was thus to decide upon the details of such benchmark system. For the definition of benchmarks in particular, the commission released in February 2009 a preliminary report stating eleven principles for a fair benchmark-based allocation [16]. In mid-2010, the end result of this comitology process was that free allocations would be allocated on the basis of approximately fifty product benchmarks. In the fourth quarter of 2010, a vote by the Climate Change Committee (ultimately comprised of member states) was scheduled to validate this end result[17] and did validate it.

The comitology process dedicated to the implementation of carbon allowances auctions outlined several of the major options available: auctions held an individual member state level, jointly organised on a single or on several common auction platforms. Other elements that were discussed in this committee was the need for common guidelines, the calendar and frequency of auctions, the quantity of auctions made available and the type of auction held (Delbosc, 2009 [16]). The publication of the draft regulation in early April 2010 featured some changes including the move from a mandatory EU-wide auctioning platform to a provision allowing member states to opt-out [18]. In addition to that, the draft regulation envisaged holding open auctions, at least weekly and all over the year. The principle of "**single-round uniform-price sealed-bid auctions**" was retained (Sartor, 2010 [20]). The Climate Change Committee adopted the regulation on July 2010.

Finally, the implementation of the earmarking of revenues from the auctioning of the phase II new entrants reserve during phase III was also discussed in the course of the comitology process. In mid-2009, it was debated whether the proceeds from the sale of some 300 millions allowances from the NER, estimated between EUR 4 and 9 billion, would be going to renewable energy and CCS projects[19]. In February 2010, the Climate Change Committee reached a decision on this and mandated the European Investment Bank to evaluate the prospects of the project (NER300) and manage the sale and use of the revenues[20].

Recent debates In May 2010, the EC released a report pondering whether it should increase the phase III emissions reduction target from 20% to 30% in the light of the economic crisis. In this report, it is argued that the crisis helped reduce the cost of emissions reductions by 20% (EUR 48 billion per annum) and that by going further this would help stimulate innovation and

[16] Tendances Carbone (2009, [18])
[17] Tendances Carbone (2010, [19])
[18] Tendances Carbone (2010, [20])
[19] Tendances Carbone (2009, [21])
[20] Tendances Carbone (2010, [7])

create green jobs. This was used in the framework of the year-end negotiations in Cancun [21]. In addition to this, the EC announced in mid-2010 that a proposal was being drafted in which it would explore the impact of implementing new qualitative restrictions on credits used for compliance[22]. This draft proposal was due for the end of 2010. In June 2011, the EC formally adopted a ban on credits from HFC-23 and N20 Kyoto projects for use in the EU ETS starting 2013.

1.2 Contemporary trends

After having discussed in great details the evolution of the EU ETS, we give an overview of contemporaneous challenges that European utilities are facing in addition to the EU ETS. Those trends affect the spectrum and the pecking order of responses that can be given to a climate change mitigation policy. We first look at other climate policies and then at the impact of the economic and financial crisis[23].

1.2.1 EU-wide and member state level climate policies

The EU ETS is not the single climate policy of the EU ETS that feature the European power sector in its scope of application. The EU set of policies to reduce greenhouse gases extends to several other types of policies both at the EU level and at the member states level. These policies are comprised of brand new policies and revisions of past directives and laws in order to make them compatible with the recently introduced emissions reduction targets.

We briefly outline some of the objectives of such policies, plus some interesting features that could justify their existence in addition to the EU ETS (other stages of the life cycle of generation technologies targeted, need to drive generation costs down, multiple objectives pursued in addition to mitigation, etc.). There is an extensive literature about the effect of such targeted policies on top of a cap-and-trade policy being the backbone of EU climate strategy. There is still some debate whether their co-existence support or create distortions with the EU ETS. This will not be discussed here (refer to Linares et al. 2008[23] for more details).

These new policies are mostly associated with policy instruments to provide the regulated utilities or independent developers with incentives to act in line with policy objectives: feed-in tariffs or tradable green certificates

[21] Tendances Carbone (2010, [22])

[22] Tendances Carbone (2010, [17])

[23] Apart from climate policies, we acknowledge that environmental policies such as the Large Combustion Plant Directive and the waves of EU directives for the liberalisation of EU power markets played a considerable role.

to achieve renewable targets or tenders and subventions for the funding of demonstration CCS projects for instance. Technology-directed policies aim at promoting specific technologies at the exclusion of or relatively to others. Technology-directed policies can be classified on (1) when and (2) what kind of support is provided along the life cycle of specific technologies. Clearly, the type of support provided need not be the same in the early stages where in-lab and small scale feasibility is to be demonstrated and in later stages where large-scale deployment is the objective.

Early stages - proving feasibility and pilot projects The early stages of the life cycle of a technology include in-lab concept and feasibility demonstration, on-site feasibility demonstration and then pilot projects undertaking. In order to address the very first stages of these technology life cycles, **public support to fundamental R&D** (national and EU-wide support via large research framework) is the typical support mechanism. In a simplistic manner, money in the form of a grant funds specific research part of agreed upon research orientations (which includes mitigation technologies). Demonstration funds and tender schemes are not exclusively for early stages but in the most recent years have been used to address technology feasibility demonstration at the scale of pilot plants.

Power generation and related technologies that have been in the scope of such early stages support include carbon capture and storage (CCS), innovative fuels with application to power generation, power storage with fuel cells, etc. Many observers, policymakers[24] and utilities are considering CCS as part of a mid- and long-term mitigation strategy for the European power sector and therefore specific support was provided. European policies targeting CCS include notably R&D support since the third framework programme of 1990-1994. CCS is more recently part of the eligible technologies (along with concentrated solar plant and smart grids) for the "NER300" programme to fund **demonstration projects** (announced in November 2010). This programme is being funded by the sale of the remaining 300 million EU ETS phase II allowances in the new entrants reserve.

R&D is by nature risky and so is its payoff (support is therefore largely ensured by governments in addition to the private sector). Besides, it could be long to deploy these technologies for substantial benefits. Still, specific technologies being developed could include potential silver bullets for mitigation. We switch to later stage support, which corresponds to large-scale deployment of proven generation technologies.

[24] The EC estimates that carbon dioxide emissions avoided through CCS in 2030 could account for some 15% of the reduction required.

Later stage - deployment of technologies The introduction of support mechanisms to renewable-based generation (wind, solar photovoltaic, geothermal, etc.) were among the most prominent technology-directed policies targeting deployment of specific technologies in the European power sector activities over the last few years. The expectation is that, by supporting specific technologies in early stages of deployment, cost reductions will follow suit until the technology supported reaches grid parity when support will not be needed anymore or when specific policy objectives have been reached. Support mechanisms impact the expected rate of return on renewable assets and ease the terms of borrowing (a specific asset being eligible to such support mechanism is a positive element for the lender).

A prevalent direct support mechanism to renewable generation is feed-in tariffs. While there are many variations in the design of **feed-in tariffs** (Couture and Gagnon, 2010[24]), the concept remains the same. A governmental agency, a ministry or an incumbent has to buy the power generated by producers of renewable energy at an agreed price (at a premium to prevailing and expected grid prices) over a long period of time (usually 20 years to cover the lifetime of an investment). Deployment of such technologies has been good so far given the generous feed-in tariffs but came with a heavy burden on either ratepayers or taxpayers. In the EU in the wake of the financial and economic crisis, governments either tried to step back in the levels of payment guaranteed (from an overall reduction in guaranteed tariffs for new projects to retroactive reduction of tariffs for solar PV in Spain) or included provisions to limit the burden on either ratepayers or taxpayers (inclusion of hard caps notably, i.e. no MW supported beyond a given capacity already supported).

Another type of support mechanisms to generation assets in use in the EU is resorting to **green tradable certificates**. Likewise, other policies in the form of tax incentives, grants or guarantees apply equally to such renewable projects or CCS ventures (or other generation technologies like CHP for instance) but they will not be discussed here. Similarly, supply-side energy efficiency policies like white certificates or tax incentives will not be discussed here. We switch to another major contemporary development, the financial and economic crisis.

1.2.2 The 2008 economic and financial crisis

The second phase of the EU ETS saw the effect of the economic and financial crisis that begun in late 2008. We will discuss some background information, impacts on power generation economics and the EU ETS compliance profile.

General impacts

The financial crisis that affected the global economy spanned the time period covering the middle of 2007 and that of 2008. The trigger was the massive losses on mortgage-backed securities caused by a series of default in the US. The accumulation of bad debt in the books of banks and the linkages with other financial institutions (counterparty risks on credit markets) caused the collapse of some prominent financial entities[25]. This caused the bailout of the major banks that survived the initial wave of bankruptcy orchestrated by European and US monetary authorities.

The crisis affected the banks' balance sheets (with plunging asset values), which restricted their ability and willingness to lend money (IEA, 2009[25]): restrictions on new loans granted, increased cost of borrowing, heightened degree of scrutiny, etc. This obviously had a magnifying effect on the economy.

The economic crisis that ensued and fuelled in turn the financial turmoil, was considered by most economic observers as the worst recession since World War II (IEA, 2009[25]). The IEA estimates that the global GDP was reduced by 5% in the last quarter of 2009 on an annualised basis. Advanced economies were even more hit: -6% for the US, -7% for the Euro area and -13% for Japan. The speed and spread of the contagion was deemed unprecedented.

The governments' response was a mix of traditional remedies (quantitative easing notably helping with the short-term effects) and government-backed stimuli packages, some of which specifically targeting the clean energy and low-carbon sectors.

Impacts specific to power generation economics

The main channels, through which the financial and economic crisis pervades and ultimately affects investment, including power generation assets, are the following[26].

First, **financing conditions** proved more difficult and harder-to-access for both ongoing projects and capital raised towards new projects. This was exacerbated for public companies that had previously borrowed money. Plunging share prices altered the gearing ratios they were supposed to maintain as part of the typical debt covenants. This pressured firms to cut their level of debt. The cost of capital increased over the period despite record low

[25] Bear Stearns and Lehman Brothers in particular.
[26] This section is mostly based on IEA, 2009[25]

LIBOR and EURIBOR rates (thanks to quantitative easing on the part of central banks).

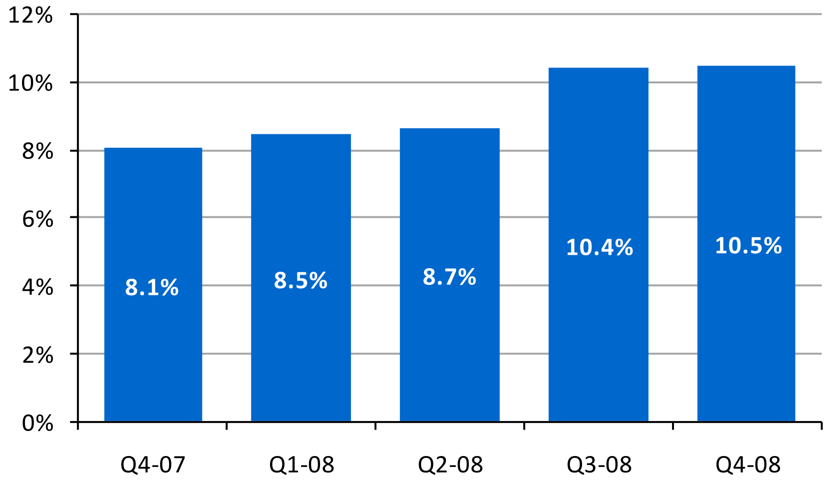

Figure 1.7: Weighted Average Cost of Capital for US electricity companies - from IEA (2009) based on Morningstar Ibbotson Cost of Capital Resource Center (2009)

Figure 1.7 illustrates the evolution of the discount factor (weighted average cost of capital) applied to investment decisions in the US power sector between the end of 2007 and the end of 2008. Clearly the hurdle rate for investment has strongly increased over the period. This reveals more stringent risk premiums demanded by investors as they perceive a higher risk.

Second, fundamentals indicate a **lower expected profitability** from investments. While energy market prices plunged over the period, costs generally remained high. The fall in carbon allowances prices in Europe also *"shifted the relative economics of power generating plant"* to the detriment of low-carbon renewables-based and nuclear power. In the power generation sector, this was marked by a lower electricity demand especially from industrials that suffered from smaller order books.

Third, there has been a **lower need for extra capacity**. This was characterised by a lower appetite for risk among investors and less urgency to invest now.

While these elements affected the entire energy sector[27], it should be stressed

[27] End-user investment in energy efficiency and savings is affected as well. And so is the global upstream gas and oil market, which in turn, impacted investment decisions in the

that not all energy-related infrastructure projects have been affected equally. In particular, the most risky projects and those funded off the balance sheet suffered slowdowns, delays and cancellations. The small, less diversified and privately-owned entities (i.e. not the major European utilities) suffered the most from the difficulties to access third-party finance (be it debt or equity). Finally, capital-intensive and projects with long lead-time were particularly exposed. Needless to say that nuclear and renewables-based projects were particularly hit over this period (wind energy projects, for instance, rely heavily on debt). To some extent, the less capital-intensive options were favoured, namely fossil-fuel power generation.

Impacts specific to the EU ETS

While in the short term, carbon emissions have been reduced thanks to the slower-than-expected economic growth, the picture is different looking in the mid- and longer-term (Deutsche Bank, 2008[26] and IEA, 2009[25]). In particular, the postponement or cancellation of clean generation projects could lead to higher emissions. This is because carbon-emitting generation projects were, to some extent, less affected by the economic and financial crisis: weak fossil energy prices and carbon allowances on the one hand, and less difficult access to third-party finance compared to capital-intensive projects like nuclear and renewables on the other hand.

This economic slowdown translated into a price correction on EUA prices. Between July 1st, 2008 and February 12th, 2009, the phase II carbon price was divided by 3.6 to reach EUR 8/ton given the revised expectations on future production and emissions levels. The crisis might to some extent have impacted the required rate of return on power plant investments upward, modified financing decisions, prospects for valuation drivers and more fundamentally the need to undertake new investments.

The behaviour of EU ETS participants in the wake of the crisis illustrates the higher flexibility of a cap-and-trade mechanism to that of a tax. On the one hand, the economic and financial crisis reduced the overall European industrial demand, be it more or less carbon-constrained. This naturally triggered a reduction in demand for carbon allowances used for EU ETS compliance. This in turn contributed to a sharp decrease in the price of EUAs. Had there been a tax instead of an emissions trading scheme, the level of the tax would have remained the same and carbon-emitting installations would have faced both a tougher economic environment and an inflexible carbon constraint.

power sector.

On the other hand, the European industry was facing tougher credit conditions and heightened liquidity availability requirement (to meet among others stringent covenants of loans). In phase I and II, EU ETS participating installations had been mainly endowed free allowances at the beginning of each year. This difference with a tax (or with a carbon market based on auctions) had quite an impact on the cost of the carbon constraint. Cash-strapped EU ETS-participating utilities monetized their excess inventory of allowances in various ways to deal with the tougher economic environment. Some entities have engaged in outright sales of carbon allowances, while other have used carbon allowances as collateral (lent their allowances in the end) to guarantee various financial transactions (margin requirement on carbon market places, borrowing, etc.). Beyond having a valuable inventory of carbon allowances that cost nothing, the effect was reinforced by market imperfections. As a matter of fact, the "repo rate" of EUAs[28], the implicit interest rate based on the term structure of carbon allowances, was higher than prevailing risk-free interest rates. Two effects magnified the extent of such transactions: EU ETS participants are allowed to borrow the allocation of the year after and the prevailing market participants sentiment was that the market was already over-allocated in a business-as-usual scenario. Therefore, as late as early 2009, there were massive sales of carbon allowances which helped discover a price resistance as low as EUR 9 in February 2009.

1.3 The spectrum of action for EU ETS participants

The impact of the EU ETS on the European power sector takes place at two levels. First, the carbon price has been introduced in operational decisions. Any time a ton of carbon is emitted over the course of the production process, the operator compares the corresponding profit margin for the production (including carbon procurement costs) with the opportunity cost of selling the allowance on the market (if allocated free of charge). Some studies have identified some emissions reduction during the first trading phase (2005-2007) in the form of fuel switching even though the cap was not that stringent (Ellerman and Buchner, 2006 [27]). Second, the carbon price can be factored in longer-term decision making - namely the decision to invest in several abatement solutions. Should the carbon price be high enough, decision-makers might consider it more advantageous to invest in carbon-free or less carbon-intensive production apparel. Hoffmann (2007) [28] notes that this has not been the case so far in the German power industry and finds that while short-term operating decisions clearly have been impacted

[28] The contract used in repurchasing agreement, in which the seller of a carbon allowance agrees to repurchase it from the buyer at an agreed-upon price and date.

the EU ETS, this was not the case for greenfield/brownfield investment decision and R&D.

Reasons invoked for that lack of investment incentives are numerous. Most policy observers argue that the cap for phase I and II of the EU ETS has been set too low to provide any effective incentive. Others note that the effectiveness of the policy was compromised by not following the policy tool "by the book" despite it was the condition for acceptance by the regulated: the allocation of most grandfathered allowances for free in phase I and II (instead of an auctioning process) and the new entrants and closure provisions (Ellerman, 2006 [29]). Finally, the existence of authorised flexibility mechanisms (banking, borrowing of EUAs and ability to surrender offsets from Kyoto offset projects) and derogatory measures in some member states are sometimes invoked as not giving the incentive to invest in carbon-free technologies within the EU boundaries.

In the previous sections, we explored European climate polices and the context in which European utilities operated. Hereafter, we will explain how an EU ETS-regulated utility can cope with the constraint established by the cap-and-trade policy. We will use elements from the academic and corporate literature. In particular, we will look at the corporate decision framework, short-term responses, longer-term responses, and non-financial and non-operational responses. We will look particularly at what the ten most carbon constrained utilities have been doing. The ten European utilities, we draw those insights from, are those with the highest carbon emissions (in MtCO2 for the year 2008) and are compiled in table 1.1.[29]

1.3.1 Corporate framework for coping with the EU ETS

In this section, we detail the corporate framework to prepare the compliance strategy used by entities whose installations were carbon-constrained: exposure assessment, comparison of alternative emissions abatement options and compliance strategy formulation and implementation. This is based on the review of the corporate literature for several entities and academic literature.

EU ETS exposure assessment

In 2003 and 2004, the first step in coping with the carbon constraint introduced by the EU ETS involved assessing exposure to the recently or

[29]Data related to annual carbon emissions are stemming from Pricewaterhouse Coopers carbon factor study for the year 2008. The estimation of capacity in GW within the EU is based on corresponding financial statements and communications for the years 2007 to 2010. The estimation of the number of installations and aggregate caps at corporate levels are derived from CDC Climat's CITL analysis database based on 2007 data.

Table 1.1: Key operating data on top 10 European utilities

	Carbon emissions - MtCO2 -	EU capacity - GW -	EU ETS inst.	EU ETS cap - MtCO2 -
1. RWE Group	138	43	70	132
2. E.ON Group	100	73	205	78
3. EDF Group	90	142	122	90
4. Enel Group	83	95	85	101
5. Vattenfall	73	39	87	85
6. DEI	53	13	29	52
7. GDF-Suez	46	68	114	36
8. CEZ	40	14	19	42
9. Iberdrola	27	32	18	7
10. SSE	23	11	40	30
TOTAL	672	530	789	654

soon-to-be introduced climate policy. Figure 1.8 illustrates the bottom-up process to estimate exposure to the EU ETS for a given entity. The EU

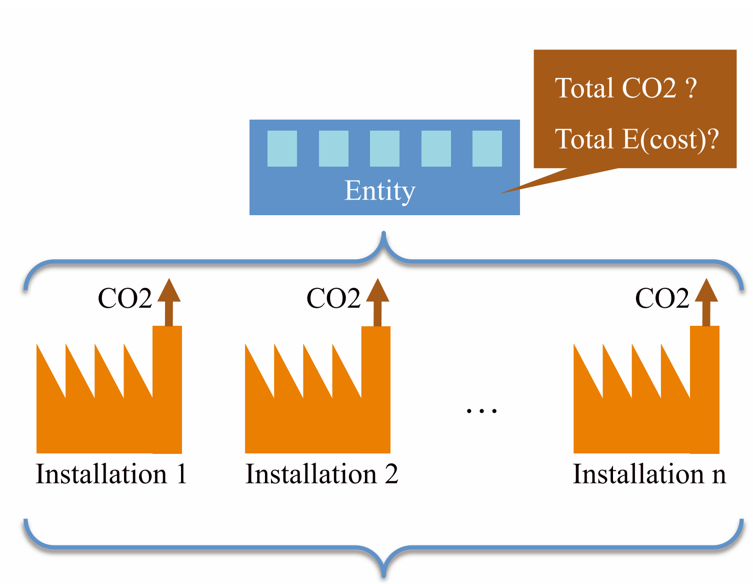

Figure 1.8: Emissions data collection and impact assessment

ETS operates at the carbon-emitting installation level. Emissions cap are assigned at this level following the consultation process of the national allocation plans (NAPs). During phase I of the EU ETS, this installation-level cap corresponded to the European Union Allowances (EUAs) endowment except for new installations that would have fallen within the scope of the Directive. Simply stated, the owner of a given carbon-constrained installation is therefore responsible for surrendering as many compliance assets as tons of CO2 the installation emitted over the reporting period (one calendar year).

Installations falling within the scope of the EU ETS are largely held by corporate entities like energy and industrial groups. The holding company has most likely several installations in its **compliance perimeter**[30]. Task forces, composed of a single individual or a team, were typically charged with collecting and aggregating installation level data in order to proceed with the EU ETS exposure assessment, including:

- Longest carbon emissions trend and the most recent carbon emissions, usually at least with a monthly frequency and a breakdown by industrial units composing a given installation. These are used to prepare emissions scenarios over the compliance period and possibly beyond;

- Technical and production data with a view to identifying specific drivers for emissions and performing sensitivity tests;

- Emissions caps based on tables in the annex of the NAPs for the various years of the compliance period and member state-level decrees. These emissions cap were in turn based on emissions data provided by installations owner or estimations, to which emissions reduction effort rates were applied.

At the end of this bottom-up process, the task force has an estimate of total carbon emissions within its compliance perimeter. In addition to this, the task force collected price projections and scenarios from various sources to build its price expectations for EUAs over the compliance period. By combining expected unit cost for EUAs and projected carbon emissions, the corporate entity obtains a figure corresponding to its expected **gross carbon financial liability**.

This is only one part of the story as EUAs were mostly allocated for free during phase I and II of the EU ETS up to the installation-level emissions cap. In other words, the compliance period begins with a large part of the compliance assets already in inventory. The combination of expected unit cost for EUAs and the annual allocation of EUAs gives the entity's expected gross carbon financial asset. The difference between the expected gross carbon financial liability and asset determines the entity's overall position. This expected net carbon position (net liability or net asset) ultimately gives an estimate of the degree of constraint for the entity and indicates the extent of compliance strategy that will be deployed.

[30]The overall picture is simplified here. More complex configurations are to be found with (1) partial ownership of carbon constrained installations or holdings thereof (the compliance perimeter could be shared among owners or assigned to one of them or the one in charge of operations), (2) changes in ownership level over time and (3) agreements to mandate a third-party to manage the compliance of some or all of the installations.

Assessment of the abatement alternatives

The next stage typically entails having the utility evaluate abatement costs and emissions reduction potential of various technologies. The table hereafter (Table 1.2) illustrates the result of the first stage of this process (based on RWE Carbon Disclosure Project submission, 2004[30]). The cheapest option is the retrofitting of a plant, while the most expensive is solar PV. With carbon prices between EUR 15 and 25 per ton, only the first five should be deployed to reduce emissions.

Table 1.2: Sample abatement costs

Avoidance cost	**EUR/tCO2**
Retrofitting of existing plant	8-11
New nuclear plant	11-15
New lignite plant	17-19
New CCGT plant	14-21
New hard coal plant	22-26
New hydro plant (subsidies included, if any)	35-45
Wind (subsidies included)	60-70
Solar PV (subsidies included)	500-600

The next stage entails estimating the abatement potential of each entry in Mt and plot a corresponding marginal abatement cost curve (MACC). This curve will be plotted in parallel of the estimated demand for abatement of a given firm. Particular attention will be given to the carbon price which will motivate investment in abatement technology or purchase of carbon allowances for compliance.

We now move to a fictional illustration (see Figure 1.9). For instance, consider an entity expecting to require net 10 Mt p.a. (expected emissions minus grandfathered allowances) over phase I (i.e. 30 Mt for the 3 years), net 25 Mt p.a. over phase II (125 Mt for the 5 years) and net 80 Mt p.a. over phase III (560 Mt for the 7 years). Depending on its planning horizon and set of expectations (quantity of emissions and allowances allocated for free and prices of allowances and abatement costs), the entity will decide on various strategies.

With a one-year planning horizon, the entity would invest in technology 1 only. Technology 1 is the cheapest option envisaged by the entity (EUR 6/ton abated) and would reduce annual emissions by 10 MtCO2 for EUR 60 million. Nonetheless, the effect could be lasting longer depending on tech-

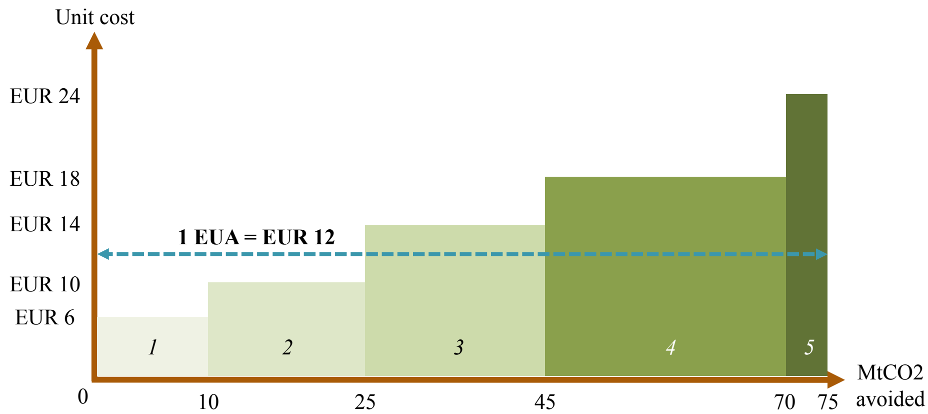

Figure 1.9: Sample marginal abatement cost curve (stepped)

nology 1 emissions abatement profile.

With an horizon as long as phase I, the entity would need to abate 30 MtCO2 and would invest in technologies 1 and 2 and purchase the remaining 5 Mt in carbon allowances. Technology 2 is the second cheapest abatement option (EUR 10/ton abated) that would reduce an extra 15 MtCO2 per annum for an extra EUR 150 million. So far, the entity would have spent EUR 210 million for 25 MtCO2 avoided. The next abatement option (technology or process 3) has a unit cost of EUR 14/ton abated - which is in excess of the task force price scenario / expectations for carbon allowances (EUR 12/ton - the blue dashed line). The entity decides it would be cheaper for the entity to purchase extra allowances at prevailing prices for the remaining five tons to abate (EUR 60 million). Overall, this strategy costs EUR 270 million. Emissions reduction induced by technology 1 and 2 could be lasting longer than the planning horizon. Carbon allowances surrendered are subsequently cancelled and have no use beyond this compliance period. This strategy is cheaper than purchasing 30 Mt of carbon allowances for the whole period for EUR 360 million without any abatement beyond the compliance period. Alternatively, the entity could have weighted the pros and cons of investing in technologies 1, 2 and 3 for EUR 490 million overall. More tons of CO2 would have been avoided over a longer horizon and extra allowances (thanks to lower emissions levels) could be sold on the market to recover some of the marginal investment costs.

With a longer planning horizon, more MtCO2 needs to be abated but either carbon prices are too low to make certain abatement technologies competitive or those technology costs are too high. Therefore, compliance needs in excess of the carbon price threshold is achieved by acquiring additional carbon assets. Results of this simplified marginal abatement cost curve are clearly depending on the horizon and specific assumptions.

The mitigation solutions deployed by European utilities indicates that they either went beyond the typical technological MACC or that they included non-technological solutions within their MACCs. Likewise, energy efficiency (demand-side) is typically included in MACC while the emissions reduction impact at the power plant level is rather limited.

Corporate mitigation strategy formulation and deployment

MACC are not providing a spectrum of action and decision-making beyond identifying abatement potential. The following stage is to translate insights from the MACC exercise into a mitigation strategy that includes all possible responses to the EU ETS constraint. This includes developing a roadmap, attaching horizon for various abatement/compliance actions and monitor the contribution to overall emissions reduction objectives (using a metric like average tCO2/MWh).

Compliance with the EU ETS implies that for each compliance period, the installations surrender as many acceptable carbon assets as verified emissions. In other words, the entities must ensure that the following relationship holds every year:

$$\text{Verified emissions}_t = \text{Surrendered carbon assets}_t \ , \forall t$$

In order to cope with the carbon constraint introduced by the EU ETS, installations falling within the scope of the EU ETS can reduce verified emissions to match carbon assets available for surrender and / or obtain additional carbon assets to match verified emissions.

On the left hand side of the equation, installations have two main ways to reduce verified emissions. First, they may reduce the emissions factor of a given production level. This can be achieved by changing operating processes, by deploying technologies (that is greenfield investment or brownfield investment) and by investing in R&D for ulterior technology deployment. Alternatively, they may reduce the quantity of carbon-emitting production at various levels: changes in operating mode, power plant mothballing (i.e. temporary closure given the economic conditions) and power plant decommissioning.

On the right-side handle, there are several ways to obtain the required carbon assets to surrender. In particular:

$$\begin{aligned}
\text{assets}_t &= \text{free allocation of allowances}_t \\
&+ \text{allowances purchased}_t - \text{allowances sold}_t \\
&+ \text{use limit.(offsets obtained}_t) - \text{offsets sold}_t \\
&+ \text{allowances banked}_{t-1,\ t-2,\ \dots} \\
&+ \text{allowances borrowed}_{t+1,\ t+2,\ \dots} \\
&+ \text{offsets banked}_{t-1,\ t-2,\ \dots} \\
&+ \text{allowances from a pool}_t - \text{allowances transferred to a pool}_t
\end{aligned}$$

In the following three sections we will discuss various ways to cope with the carbon constraint: short-term adjustments, longer-term adjustments and non-operational, non-financial responses.

1.3.2 Short-term actions in the European power sector

Short-term actions for the European power sector are comprised of changes brought to the operation of existing power generating assets, carbon trading and purchase agreements to acquire primary offsets (CDM and JI mechanisms of the Kyoto Protocol). Short-term is employed here in the sense that the corresponding actions do not alter permanently the structure of the power generation entity.

Changes in operations

European utilities routinely resort to optimisation models and procedures to maximise the value of the power generated by the power plant they can deploy under a set of constraints (according to RWE financial statements, *"in RWE's daily business, all emissions trading related issues have been implemented in the regular operations of the dispatch of power plants and trading activities"*). The carbon pricing established by the EU ETS translates into higher generation costs for power generators. During phase I and II of the EU ETS, this is true to the extent that we consider the opportunity cost or market value of allowances that have been allocated to incumbent power generators mostly gratis. Consider a lignite-fired power plant with a marginal generation cost of EUR 40.0/MWh and a gas-fired power plant with a marginal generation cost of EUR 50.0/MWh. Adding a EUR 20.0/ton of CO2 on top of this increase plant the lignite-fired power plant marginal generation cost to EUR 58.0/MWh (assuming an emissions factor of 0.90 tCO2/MWh) and that of the gas-fired plant to EUR 57.2/MWh (assuming an emissions factor of 0.36 tCO2/MWh). Because of the carbon price, the once cheaper-to-run but highly emitting power plant will be dispatched later as the gas-fired power plant was promoted in the merit order. Three main operation changes have been used to reduce emissions: fuel switching, reduced quantity of power generated and passthrough of carbon prices to customers.

A major way to modify the emissions of a given power plant is to resort to **fuel switching** for boilers able to accommodate various fuels. The plant operator will optimise its production margin by adjusting the relative quantity of more or less carbon-emitting fuels depending on fuel and carbon prices and taking into account operational constraints (ramp up time, etc.). The following fuel switching equation indicates the carbon price required for an operator to be indifferent between generating electricity using coal (G_{coal} denoting the corresponding generation cost expressed in EUR per MWh) and using natural gas (G_{gas} denoting the corresponding generation cost).

$$\text{Switching price} = \frac{C_{gas} - C_{coal}}{EF_{coal} - EF_{gas}}$$

EF corresponds to the emissions factor of the two fuels (expressed in tCO2 per MWh). Should the prevailing carbon price be higher (lower respectively) than the theoretical switching price, it is more profitable for the producer to generate electricity using natural gas (coal respectively). Fuel switching was a major EU ETS-induced lever to abate emissions. It was estimated that fuel switching contributed to the abatement of 53 MtCO2 in 2005 and 2006 (Delarue et al. 2010[31]). According to RWE 2008 financial statements, *"the generation system allows a fuel switch from oil to gas. The production schedule of our power stations is continually optimized on short, medium, and long term time frames according to the current price, including CO2 emission prices"*[30].

An alternative to reduce emissions at the operational level is to **change the quantity produced**. This occurred when demand is lower than usual (during the peak of the economic and financial crisis) and more emitting marginal peaking unit are not called. This can also occur on the supply side when fuel and carbon prices are too high to produce electricity at market prices. Because of high coal and carbon costs, RWE reported that third party power plants capacity (that the group is able to deploy) utilization *"decreased considerably"* in 2005.

A related way to reduce carbon procurement costs is to generate additional resources by **passing through** the carbon price to electricity customers. Most allowances have been allocated for free during phase I and II of the EU ETS. Therefore, they bear a null accounting cost. Nonetheless, European utilities able to exercise market power have been passing through the carbon cost at prevailing market prices into electricity prices. In 2008, RWE reported that, in phase I, it managed to transfer the costs associated with the provision of allowances to RWE retail price. Competition authorities acted to prevent such practice afterwards (this is discussed in more detail in the latest section of this chapter).

Carbon trading and risk management

In a cap-and-trade policy, the trade component is what gives compliance buyers flexibility in meeting their emissions reduction objectives. It is the alternative to reducing emissions directly. Compliance buyers may acquire additional compliance assets from others (both allowances and offsets), their future allocation, unused compliance assets set aside and their other installations (in excess of allowances).

Carbon allowances can be **acquired from others** to cover the shortfall. Primary allowances are typically allocated for free during phase I and II but in other cases can be obtained in the course of government-led auctions. This auction procurement channel will be generalized in phase III of the EU ETS. Secondary allowances can be exchanged (1) on market places (Bluenext, The Green Exchange, ECX, EEX, etc.) offering standardized contracts and clearing houses, (2) via carbon brokers offering tailored contract specifications and (3) in bilateral transactions. At the beginning of the European carbon market, most of the transactions were organized by brokerage houses. In the most recent years, market places took over the lead. Carbon allowances can be purchased spot, i.e. delivered almost instantaneously. Alternatively, they can be purchased using derivative transactions: forward and futures for *firm* delivery at a price agreed-upon at the time of the transaction and at a fixed date ahead in time or call options for *potential* delivery at a price agreed-upon at the time of the transaction and at a fixed date ahead in time. The latter derivative contract comes with a cost, the option premium paid by the buyer to the seller of the option in the case of a call. Allowances purchased spot can be held in inventory until the annual true-up event (surrendering as many allowances as the entity emitted tons of CO2). The purchase of allowances using derivatives can be made to coincide with the true-up event. Typically, carbon trading desks reduce the carbon price risk exposure by using derivative transactions as much as they can (following the maturity of the most liquid contracts). They end up having a carbon procurement cost reflecting the average price of the 2-3 most recent years. In the 2009 outlook for 2010[30], it is outlined that RWE's work *"also includes reviewing options for (...) buying CO2 certificates on the wholesale market for future periods early on"* and it was reported that RWE was already buying EUAs for phase III.

An alternative to purchasing carbon allowances is to **acquire carbon secondary offsets from CDM and JI projects** (i.e. offsets that have already been issued by UN bodies - the purchase of a stream of offsets from an emissions reduction project will be discussed in the next sub-section). Carbon offsets from the CDM and the JI can be used for compliance in lieu of allowances according to the linking directive (Directive 2004/101/EC[31]). Primary and secondary CERs and ERUs can be used up to a certain percentage of surrendered compliance assets: 13.5% on average in the EU but the percentage varies from 0% to 20% among member states. This limit on the use of offsets makes them less valuable than EUAs. They are indeed less fungible and emissions reductions from the related projects typically were obtained for cheaper than in the EU. The discount of secondary CERs

Figure 1.10: Price spread between Phase II EUAs and secondary CERs in EUR per ton - based on Bluenext data

to EUAs evolved a lot during the recent years (see Figure 1.10) reflecting changes in relative risk perception (quantitative and qualitative restrictions on the use of CER in the EU ETS in phase III), tensions on the supply of primary CERs, and the effect of some speculative trading strategies. Secondary CERs are nonetheless always more expensive than primary CERs as they are free of project-specific risk and have either been issued or their delivery is guaranteed. Offsets have been used by compliance buyers to reduce compliance costs by either surrendering CERs instead of EUAs or swapping EUAs for CERs thereby cashing in the price differential. For more details on the use of CERs for compliance in the EU ETS, refer to Trotignon (2011[32]).

A third major way to obtain additional compliance assets is to **resort to**

[31] Directive 2004/101/EC of the European Parliament and of the Council of 27 October 2004 amending Directive 2003/87/EC establishing a scheme for greenhouse gas emission allowance trading within the Community, in respect of the Kyoto Protocol's project mechanisms.

intertemporal flexibility: borrow allowances from next years' allocation or "bank" (i.e. carry forward) current allowances in excess of compliance needs for use in subsequent years, etc. Among the main advantages of this flexibility mechanism, the compliance buyer can engage in a multi-period management of emissions reduction efforts and the procurement process is performed internally. Both EUAs and offsets are eligible to intertemporal flexibility. For example, all of RWE's CERs for phase I were banked over phase II given the delivery and offset registry constraints. Still, there are some limitations to this mechanism. The intertemporal link between phase I and II for EUAs was removed by the EC to prevent the contagion of phase I over-allocation to phase II. Apart from this, intra-trading phase transactions and transactions between phase II and III are unrestricted as long as compliance is achieved annually.

A final compliance asset procurement channel is the use of **pooling agreements**. Most often informal and organised at the corporate level, the pooling of installations creates a pool thereof facilitating allocation, transfer and surrendering events. In 2007, RWE resorted to corporate pooling and transferred the allowances it had in surplus in the "others" category (Hungary, etc.) for compliance purpose in Germany and in the UK[30].

Primary CDM and JI projects

Instead of acquiring readily available Kyoto offsets or whose delivery is guaranteed, (i.e. offsets that can be acquired on secondary markets), regulated entities have also purchased the stream of offsets from CDM and JI projects. Acquisition of primary CERs and ERUs can be achieved in two separate ways: European utilities have both "invested" directly and indirectly into UN-labelled offset projects[32].

As regards direct purchases, European utilities have engaged in almost all aspects of carbon project origination:

- Pre-project activities: definition of the investment policy and screening of project opportunities within the investment policy (meeting criteria, specific requirements, etc.);
- Project design documents drafting;
- Negotiation of related purchase contracts;
- Industrial involvement: development and implementations of projects;

[32] There are various preferences within European utilities: some clearly preferred direct investment (EDF), while for others the bulk of investment was through intermediaries (80% for RWE in 2009).

- Monitoring: supervision of the full cycle of the projects from approval to monitoring at later stages;

- Verification of avoided emissions and related issuance of carbon credits;

- Project performance evaluation;

- Related financing activities: initial capital, loans, etc.

For some utilities (EDF and Vattenfall notably), project origination was organised, at least to some extent, within a dedicated carbon procurement fund.

There are clear benefits to direct purchases. First, primary carbon offsets obtained by direct purchases are cheaper than secondary carbon offsets or than intermediated primary carbon offsets. Second, buyers have the ability to use extra carbon offsets for voluntary offsetting or to sell extra carbon offsets to clients for their energy services business unit, to competitors or more generally on the secondary market. This effectively turns some compliance buyers into carbon offset providers. Third, it should be noted that utilities could also be the owners of the corresponding industrial projects. Ownership entails benefiting from the corresponding industrial activity: revenues from electricity sales, obtaining cheaper fuel from a biomass plant, increased control over the stream of CERs, etc. Following privatisation of electricity generation assets in Russia, European utilities took majority stakes in the newly formed entities. These entities were natural candidates for JI projects (E.ON for instance). Similarly ownership of power generation in South America offered nice prospects for CDM projects (EDP for instance).

Regarding indirect purchases, three main categories of participations have been reported: (1) investment in third-party carbon funds, (2) engaging into long-term carbon procurement contracts and (3) participating in carbon offsets tender process (auctions of primary CERs, etc.).

Analysing information from the pipeline and corporate communications, we find that European utilities have resorted to three broad categories of primary CDM and JI investments (be they acquired directly or indirectly):

- **Participation to "familiar" projects**: that is investments in CDM and JI projects with some similarities to the investor's activities. These similarities cover business activities (micro or renewables power generation CDM projects for instance), foreign market penetration or consolidation thereof and technologies at various stages of development. In addition to compliance with EU ETS requirements, that category of investment illustrates a search for corporate synergies.

- **Participation to "low-cost" projects**: clearly the sole objective of this category of projects is to ensure a cheaper compliance to the utilities. Utilities typically do not boast about such projects given that the environmental impact of such projects is sometimes questionable (stakes in HFC23 CDM projects for instance). The only exception would be early investments (before 2004) in CDM projects.

- **Participation to "good reputation" projects**: within this category of projects, the secondary objective (compliance aside) is to earn reputation gains. The investor hopes to benefit from good corporate literature, environmental ratings and press coverage. A typical investment within this category would be investment in the World Bank Community Development Carbon Fund (carbon fund whose stated investment policy is ensuring a positive community impact).

1.3.3 Impact of the EU ETS on generation investments

We now consider long lasting emissions reductions triggered by corporate investment in generation: incurring a more or less large capital cost today to ensure a comfortable production margin that will be less eroded by the carbon constraint imposed by the EU ETS. Three types of investments in generation, ranked by horizon of potential deployment, are considered: brownfield, greenfield and R&D investments.

Brownfield investments

Utilities with existing generation capacity can invest in various ways in their own power plants over their lifetime to alter the emissions factor thereof. We distinguish three categories of brownfield investments: plant capacity, improvements and lifetime-related investments.

A power plant **repowering** entails increasing the nameplate capacity of a unit. In case the power plant is repowered with identical technology (a secondary gas turbine unit added to an existing gas turbine unit for instance), the power plant capacity is increased and so are the revenues. On the other hand, the utility incurs an upfront capital cost which is usually consequent and will bear additional fuel and carbon procurement costs (linear increase). In case, the power plant is repowered with a cleaner technology (adding a CCGT unit to an existing gas turbine), capital cost incurred is typically higher, fuel costs might change and carbon procurement costs remain the same or increase to a lesser extent. A power plant **replacement** entails removing a unit and replacing it with another one. Typically the unit being removed is obsolete, not meeting environmental requirements or desired characteristics for the utility's generation fleet. We can assume that the replacement unit can be either cleaner (i.e. less carbon intensive) or more efficient. In the first case (cleaner unit), carbon procurements costs are reduced (not considering a CCS module here). In the second case (more efficient unit), less fuel is required to produce a single MWh and carbon procurement costs are reduced if a fossil fuel is used. In both cases, the capital cost is high and capacity varies accordingly.

Existing coal-fired power plants can be retrofitted with one of the three main CCS techniques (**CCS retrofitting**) but most likely post-combustion CCS. The carbon procurement costs are severely reduced but so is the thermal efficiency; thereby exposing the generating unit to higher fuel costs. Investments targeting **feedstock diversification** allow to burn biomass for instance in place of fossil fuels. The boiler is usually retrofitted to accommodate a given percentage of non-fossil fuel. The effect is a reduction of carbon emissions (and procurement costs) and fossil fuel costs. Finally, changing components in the combustion process can **increase the efficiency** of existing fossil fuel generation. This investment would reduce the quantity of fuel required and thereby emissions.

Regarding the **shutting down** of a plant, we consider two options: (1) shutting down the plant for good and (2) mothballing the unit. In the former case (early closure), in exchange for a relatively small capital cost, we stop the revenue and cost stream from a given unit. In the latter case (mothballing), we do the same but temporarily in order to keep the option to reactivate the unit later on. By incurring **rejuvenating expenses**, we extend the operating life of power plants by incurring a large capital cost. A direct effect is to slow the shift to a new generation fleet. This typically applies to nuclear units.[33]

Greenfield investments

Greenfield investment relates to investment in brand new generation capacity. Unless existing carbon-emitting capacity is decommissioned and replaced by low-carbon greenfield capacity, new investments are not reducing a utility's emissions. They do so in a longer term and reduce the average emissions factor by diluting the proportion of carbon-emitting capacity. On a forward-looking basis, the choice of a specific generation technology has important consequences for the potential tons of CO2 locked-in with that

[33]In EDF financial statements for 2008 ([33]), it is reported *"EDF's objective of extending the average lifespan of the plants to beyond 40 years. (...) EDF has already begun industrial action plans and research and development plans with the aim of extending the operating life of nuclear plants significantly beyond 40 years, through appropriate measures in response to obsolescence of certain components (particularly reactor vessels and confinement enclosures which are considered non-replaceable, and renewal of certain major facilities). These plans are expected to require long-term investment of some EUR 400 million per unit"*.

investment over its lifetime (ignoring retrofitting investments).

Chapter 2 will be dedicated to the question of greenfield investments, so we will stick to installed capacity figures in the EU27 as the end of 2007 for the moment as a reference point (EURELECTRIC, 2009[34]) and discuss in greater details operating investments in the next chapter. Among the non-carbon emitting generation (350 GW in 2007), hydroelectric generation ranked first (17.7% of the maximum net capacity in the EU27) at the end of 2007 with 141 GW installed. Nuclear generation represented 16.7% of the maximum net capacity at the end of 2007 with 133 GW installed. Third comes onshore wind with 32 GW installed at the end of 2007. The remaining 20 GW of carbon-free or low carbon generation are comprised mainly of biomass & biogas, waste, and solar energy. Among fossil fuel generation (441 GW in 2007), natural gas-fuelled generation ranked first (14.9% of the maximum net capacity) at the end of 2007 with 119 GW installed. This is closely followed by coal (105 GW) and by lignite (54 GW). Finally, 37 GW of oil-fired generation, 23 GW of multifuel-fired generation and 7 GW of derived gas were installed at the end of 2007.

R&D investments

Another way to cope with emissions constraints, but clearly in the longer term, is to invest in R&D in order to reduce emissions from fossil fuel generation and to drive down the costs / improve the performance of non-fossil generation to make the latter competitive with conventional thermal generation (grid parity). Still, the payoff of R&D is not immediate and failure rates in technology research can be high. Regarding investment in generation R&D, we account for five broad categories: ultra-critical plants / high-efficiency coal-fired generation, CCS, renewables pilot projects, nuclear and a various category comprised of CHP and fuel cells.

Research into **improving the efficiency** of existing and future fossil generation drew much attention in Germany with notably (1) RWE and E.ON research into steam power stations able to operate at 700°C. and (2) RWE's lignite drying method for power plant combustion processes. Still with fossil fuel generation, **carbon capture and storage R&D** represents one way to reduce emissions in the longer term. The three major capture technologies being tested on are: (1) oxyfuel (oxygen replaces air during the coal combustion process leaving an *"exhaust steam of almost pure CO2 and water"*[34], (2) pre-combustion capture (gasification of coal and CO2 removal from this gas) and (3) post-combustion capture (CO2 scrubbing from the exhaust steam). Research is typically conducted in public-private research consortia associating governments, industry and universities. Research on storage is

[34] E.ON 2009 financial statements[35].

performed with feasibility studies and geological surveys of aquifers.

Research into carbon-free or low-carbon generation was also quite significant. First with **renewables R&D**, large European utilities focused their efforts on offshore wind technologies (offering steadier wind regime and providing an alternative to the best onshore sites already exploited), concentrated solar power, biomass (RWE research into the use of corn for the production of biogas[35]), biomethane (E.ON plants transforming tons of organic material into million cubic meters of "carbon-neutral" biomethane), and some wave, ocean, tidal and geothermal research as well. Partnerships dedicated to renewables R&D and pilot / flagship project were also launched in parallel to the EU ETS. Among others, the Desertec Industrial Initiative[36] aims at large scale PV & wind deployment in Northern Africa with a view to transmitting back part of the power generated on European power grids. Second, research into **nuclear** was targeting both high safety standards for power stations and next-generation nuclear power. Finally, smaller but still significant amounts of R&D efforts are being dedicated to research into **small scale / micro CHP** and **fuel cells** for home and industrial applications.

1.3.4 Non-financial and non-operational strategy

In this section, we discuss additional strategies that have been set up by EU ETS compliance buyers in order to cope with the carbon constraint. Rather than being purely operational or investment alternatives, these strategies build on the flexibilities of modern entities able to alter their structure, their bargaining power and influence their business environment. These strategies are comprised of organisational changes, commercial engineering practices and lobbying to the EC and to the member states in which installations operate.

Organisational changes

There has been several organizational changes initiated because of climate policies in the European power sector over the last several years. These changes range from assigning dedicated personnel or task forces to policy analysis to dedicated subsidiaries to implement action plans with sizeable budgets at hands. A preliminary stage has been to set up **dedicated teams** and gain knowledge of the policy. These teams were in charge of identifying risks and opportunities related to climate policies and formulating recommendations and action plans for further implementation. Ownership of the implementation of the aforementioned actions plans was subsequently given to the entity on its own, through partnerships or by transferring part or all

[35] RWE 2007 financial statements[30].
[36] http://www.desertec.org/.

of the policy exposure management to a third party entity.

Since 2004, the major European utilities subject to carbon constrained generation and renewables requirement have set up **dedicated energy technology ventures** to help them achieve their goals. Existing corresponding assets and resources have been usually pooled in those entities.

In the renewables area, the main pattern has been to first set up a 100%-owned dedicated subsidiary on the operations market of origin and then create joint ventures for renewables energy projects on foreign target markets or specific technologies. Following this pattern, RWE set up RWE Innogy in 2008 in Germany for global operations and subsequently RWE Innogy Italia in 2008 (a joint venture with Fri-El Green Power) for the development of wind projects (960 MW expected to be completed between 2012 and 2013) and biomass projects in Italy. Likewise, EDF Energies Nouvelles was set up in 2004 with a pooling of existing assets and resources (SIIF Energies) in partnership with the Mouratoglou Group and subsequently EDF Energy Renewables in the UK, a 50-50 joint venture held by EDF Energies Nouvelles and EDF Energy (the UK subsidiary of the EDF Group), was set up in 2008. Other major renewables-focused entities include Enel Green Power, which was created in 2008 and to which was transferred some 4.5 GW of global existing renewables capacity plus many projects from its parent company[37]. The trend reverted in 2010-2011, with dedicated subsidiaries being merged back with parent companies. The two most recent events were Iberdrola Renovables merging with Iberdrola in July 2011 and the delisting of EDF Energies Nouvelles in August 2011 (with EDF purchasing the 50% it did not already owned).

Carbon trading desks remained an internal component in all cases given that the entity engaged both in compliance and proprietary trading. The already-existing trading desks[38] incorporated carbon as a new commodity to trade. Traders are in charge of trading secondary offsets, procuring carbon allowances, etc. Regarding carbon project origination, specific entities or budgets have been set aside. In 2005, RWE Power (the continental power generation business unit of RWE) created a "special organisational unit" in charge of managing CDM and JI projects. The unit was initially endowed with a EUR 150 million budget. In addition to that, several European utilities have set up carbon funds on their own for group-wide carbon assets procurements most essentially and third-party transactions as well. The

[37] In the energy efficiency field, several entities have been constituted as well more recently RWE Effizienz, a wholly-owned RWE subsidiary, set up in 2009 whose aim is to develop smart metering, smart homes and electric vehicles solutions or E.ON Metering, a wholly-owned E.ON subsidiary, set up in 2009 to develop smart metering solutions.

[38] EDF Trading, RWE Supply and Trading, E.ON Energy Trading, etc.

largest one is EDF Trading Carbon Fund. In 2008, E.ON Climate and Renewables GmbH, a 100% E.ON-owned entity, was incorporated. It is focused on managing and expanding E.ON's global renewables business and coordinating climate-protection projects (wind, biomass, hydroelectricity, waste-to-energy and coal-to-gas fuel switching). This last business model combines the carbon assets procurement entity with that of a dedicated renewables project developer entity.

The creation of consortia dedicated to CCS, renewables (especially large offshore wind projects) or nuclear ventures has been another major trend. These dedicated special purpose vehicles have often established with technology developers and/or competitors. Venture-related risks (policy developments and technical risks mainly) are shared by participating entities. Partners aim at knowledge sharing but the main reason why is securing affordable financing and transfer (resort to EPC contractors), share or isolate specific risk (non-recourse loans for instance).

Finally, another solution has been to **transfer part of the additional risk** imposed by climate policies to a third-party entity by contracting. This was usually performed for carbon offsets procurements with direct transactions will sellers, brokers and carbon funds.

Commercial engineering

European utilities have been involved in innovative contracting (outside price and quantity risk management) that has influenced their EU ETS compliance perimeter. As was put forward by RWE, the rationale is *"to make use of capital-conserving ways of reconfiguring"* generation portfolio.

First, European utilities have signed **long-term agreements** to deploy power plants beyond their ownership perimeter. The deployment of these power plants by means of long-term agreements entails compliance with the EU ETS but also the ability to use allowances allocated for free to these third-part power plant. Depending on the emissions profile of these power plants, the group-wide EU ETS compliance can either be facilitated or complicated. In 2007, RWE reported such a long-term contract. The deal involved RWE and Evonik, where the latter would sell RWE hard coal- and lignite-based generation with transfer of full CO2 risk to the customer (i.e. RWE). Also announced by RWE in 2009, long-term supply contracts with a full transfer of the CO2 position over 2013-2020 for a lignite-based supply contract (264 MW) and over 2013-2037 for another lignite-based supply contract (110 MW).

Second, European utilities agreed to enter into **generation swaps**, where one entity would give access to x MW of earmarked generation against y MW of earmarked generation from another entity. The aim is to easily and temporarily alter the exposure to specific factors: carbon allowances price risk, renewable generation requirement or fuel price risk. In our case, a generation swap for cleaner (less emitting) generation would contribute to lower group-wide emissions (swapping baseload lignite/hard-coal generation for peakload hydro generation[39]).

Lobbying and legal challenges

Another area where utilities have been quite active in the field of responding to European mitigation policies is that of lobbying and legal challenges. In particular, European utilities have been involved at four levels: providing support to the policymaker, complaining about policies expected and existing impacts, formulating formal demands and initiating legal challenges against policymakers of all kinds. These lobbying and legal activities have been either performed directly (with representations in Brussels and in Member states) or via umbrella / advocacy organisations (Eurelectric, IETA, etc.).

First, it is common practice for large European organisations like major utilities to be consulted and interact with policymakers as regards various policies (**supporting policymakers**). As such, European utilities have proposed their help to national governments and European representatives in drafting national allocation plans (NAPs) and supported emissions trading authorities in various ways. That way, they might have been able to influence or shift policies towards less constraint and more opportunities.

On the one hand, they have been able to successfully shift policies in favour of them to some extent by playing by the rules in place. In 2004, RWE reported having participated in the German and UK political decision-making process. RWE declared that the inclusion of 2003 in the UK baseline period and that additional allocation to mothballed units returned to service would benefit its UK-based entity. In 2005, Vattenfall congratulated itself for managing to see its early actions recognised in the German NAP for phase I.

On the other hand, European utilities attempted, most often unsuccessfully, to influence the whole policy design especially when phase II NAPs were negotiated and before the entry into force of phase III. In 2007, E.ON proposed a package of reforms to harmonize and enhance the efficiency and transparency of the EU ETS. In 2006, Enel defended its position regarding the future of the EU ETS, that was an evolution towards (1) an entirely bottom-up political process, (2) unlimited use of Kyoto project mechanisms

[39]Reported by RWE in 2010's SRI company presentation.

and (3) establishing a firmer regulatory framework, by *"lengthening the trading period (e.g. 10 years) and taking allocation decisions ahead of time (e.g. 5 years prior to the start of each trading period) so as to enable a more adequate planning of investments"*. In 2005, EDF defended a framework with a long-term view that would promote investment in low-emitting and carbon-free generation on a global scale. In 2008, EDF argued in favour of a common European allocation system that would be possibly auction-based. In addition to that the French energy group defended the view that *"zero-carbon electricity generation projects, in particular large hydro and nuclear, (...) be accepted under the flexibility mechanisms, or equivalent"*.

Second, European utilities have **complained to their representative bodies** whenever a challenging ETS-related decision had been taken or proposed. The lower emissions caps suggested in national allocation plans drafts for phase II were highly criticised by market players for example.

An obvious criticism that emerged from European utilities was that the EU ETS would cost them too much. One response was to challenge policy-makers for imposing on European utilities such a constraint. In 2006, Enel anticipating a shortfall of carbon allowances to meet its compliance needs in Italy over 2005-2007 challenged[40] (1) the Italian decree transposing the European directive for phase I allocation and (2) the Italian decree for phase II NAP approval. Similar decisions have been taken in its Spanish affiliate, this time *"challenging the criteria under which allowances will be allocated among installations using the same technology but owned by different operators"*. Nevertheless, they announced that, in parallel, they would tap into their share of the new entrants reserve and purchase carbon allowances on the market to cover the shortfall[41]. When the EC slashed phase II NAPs, member state governments sometimes challenged the EC decisions on their own, which was in the interest of owners of carbon-constrained installations. That was the case for Slovakia in 2006.

Moreover, early exhaustion or inability to tap into new entrants reserves (NER) in some countries (Italy for instance) was a major concern for power plants developers. In Italy, Enel obtained allocations and awaited allocations for new power plants or new units over phase II. However, the "national ETS committee" concurrently indicated the early exhaustion of the NER. At the time of writing, the resolution of this issue was still unclear though[42].

In addition to that, European utilities often warned that more constraints

[40] Enel lodged an appeal with the Regional Administrative Court.
[41] Enel annual report, 2005 and 2006.
[42] *"Legislative provisions to redress the situation are expected."*

(like auctioning, a decreased cap, less offsets, etc.) would challenge the realisation of further investment in generation. In 2006, RWE asserted that the German NAP II draft was to blame for *"increasing the commercial risk involved in building power plants significantly"*[43]. In 2007, there were public claims that the *"political framework (...) must not jeopardize investment economic feasibility"*[44]. In 2008, RWE pronounced against the full auctioning of carbon allowances in phase III and asserted that it would make *"the construction of new coal-fired power plants virtually impossible"*[45].

A third type of target was **non-ETS but related demands**. This concerned mostly direct support or regulation on specific more or less carbon-emitting generation technologies. Utilities demanded improved framework for carbon capture and storage, renewables and nuclear should budgeted capital expenditures be performed as planned. This was especially true in Germany and Italy regarding nuclear generation.

Finally, European utilities have **challenged competition authorities and ministries** to maintain their right to passthrough the market value (opportunity cost) of allowances allocated for free in wholesale power prices to non-regulated industrial clients. As early as 2005, RWE and E.ON have been subject to criticisms and statements of objections by the German Ministry of Economy and the German Federal Cartel Office (*Bundeskartellamt*) regarding this practice. Both utilities argued that this was common practice[46]. In particular, the fact that power prices included more than 25% of the prorated value of carbon allowances (that were allocated free of charge) was highly criticised. The legal procedure engaged by the German Federal Cartel Office could have led to reimbursement claims or industrial clients withholding partial payments. In 2007, the Bundeskartellamt dropped the charges against RWE that settled by agreeing to auction power generated by its hard coal- and lignite-fired plants (1,575 MW per annum from 2009 to 2012). It was agreed that the auction starting price would *"be the full cost of a written down hard coal or lignite power station"* and that *"the cost advantage resulting from free allocation of EUAs" would "be included"*.

1.4 Conclusion

In this chapter, we laid out the climate policy framework, almost exclusively the EU ETS, and room for manoeuvre to cope with the increased pressure on

[43]RWE annual report, 2006.
[44]RWE annual report, 2007.
[45]RWE annual report, 2008.
[46]*"E.ON Energie made it clear to the Bundeskartellamt that pricing CO2 allowances according their market price and treating them as a cost of operating a power plant is a standard market and competitive practice."* (E.ON annual report, 2006)

the European power sector. We discussed the introduction of the EU ETS and its gradually increasing constraint on the generating margin of power generators. We showed that during the first two phases of the market, the constraint imposed on covered installations was relatively low in comparison to what is expected with the third phase of the EU ETS starting in 2013. European utilities nonetheless benefited from transitory measures and some provisions to make them swallow the pill: use of offsets, intertemporal flexibility, allocation of grandfathered allowances for free, etc. Since its beginning, the EU ETS was a work-in-progress market whose major and sometimes complex building blocks were being decided upon along the way. This gave rise to much uncertainty for compliance buyers. Concurrently to the introduction of the EU ETS, a flurry of technology incentives were being deployed at the Member states level and the financial and economic crisis complicated investment decisions in power generation.

In order to cope with the EU ETS-caused erosion of margins, European utilities have resorted to a mix of three approaches:

- **Reducing emissions**: either in the short-run by switching feedstock for boilers and reducing production or in the longer run by investing in existing generation (retrofitting, replacement and rejuvenating expenses), new generation and R&D;

- **Acquiring additional compliance assets**: purchases on the market of carbon allowances and secondary offsets, borrowing next years' allocation of allowances, using unused banked allowances or purchasing entire streams of offsets from emissions reduction projects eligible to Kyoto flexibility mechanisms;

- **Altering the compliance perimeter and attempting to change the rules**: organisational changes performed by European utilities, generation swaps involving carbon allowances, lobbying and legal challenges.

Three main lessons can be drawn at this point. First, expected policy impacts, like resort to fuel switching and carbon trading, did play a significant role. Second, more long-lived emissions reduction (beyond those (1) fundamentally caused by the relative prices of coal and gas and (2) accelerated by the price of carbon) did not occur as much as was expected. According to compliance buyers, this was the result of an constantly changing environment without much long-term view. According to market observers, the cap, still too high, was unlikely to trigger long-lived emissions reduction. Third, some unexpected or at least less conventional responses were recorded (generation swaps and challenging national authorities and / or the EC in particular).

In the next chapter, we will zoom on this important question of investment in generation by analysing the pipelines of the five most carbon-constrained European utilities in the light of EU ETS developments.

Chapter 2

Operating and financial investments by European utilities over 2004-2009: what role for European climate policies?

Putting a price on carbon emissions clearly aims at giving a tangible incentive to regulated entities to factor this new input in operation and investment decisions. The longest and most complete experience so far has been the introduction of the European Union Emissions Trading Scheme (EU ETS) in 2005 covering more than 12,000 combustion installations with a capacity over 20 MW over the European Union and Norway.

So far, there has been evidence of factoring the carbon price in operating decisions, especially for European power generators that are covered by the scheme and who bear most of the constraint (i.e. have been rather under-allocated grandfathered allowances for free compared to their industrial sectors counterparts). While the short-term impact clearly is in the spirit of the EU ETS policy design, there have been many expectations and questioning about the impact on long-term decision-making, that is investment decisions. Has the EU ETS actually given the proper incentive to invest in low-carbon generation and, if so, to what extent?

Still, the assessment of long-term impacts has been fraught with several difficulties. In particular, the lack of transparent, detailed and readily available data on corporate investments was often criticized by the European regulator in this respect[1].

In this chapter, we present the results of a survey of corporate investments

[1] *"The problem that requires action is the lack of consistent data and information on investment projects (in their different phases) and the related shortcomings. Data, whatever source, is not always complete, reliable or fit for the required analysis (...). Without appropriate data, the Commission is not in a position to (...) evaluate EU energy policy and support policy-making with official data"* EC, 2009([36]).

by the five most carbon-constrained European Union utilities (RWE, E.ON, EDF, Enel and Vattenfall) from 2004 (one year before the entry into force of the EU ETS) and 2009 (the last common date for an aggregate and audited data sample). We base our survey on companies' official corporate literature (financial statements and annual reports mostly) and official communications to the investor community and the media. We cover both operating and financial investments.

Operating investments correspond to long-term assets that contribute directly to the business activity of the sample companies (infrastructures like power plants for instance). This type of data is typically embedded in the so-called property, plant and equipment (PP&E) accounting category. Our expectation is to be able to track changes and trends related to European carbon emissions mitigation policies.

In addition to investing in PP&E, European utilities resorted to external growth to pursue their strategic orientations. There are several reasons for engaging in external growth rather than investing internally. Most often the external target represents a strategic objective that either cannot be obtained internally or can be obtained easier externally (at a cheaper cost for instance). Target foreign market penetration (Eastern Europe, the UK, etc.) and specific know-how, like in the field of renewables, are typical barriers. In addition to that, the acquirer may also judge that the target is relatively undervalued compared to the market consensus and / or would be worth more under its own management. Another popular rationale for mergers and acquisitions is the ability to exploit synergies from business combinations. Simply stated, this reflects the view that a combined entity would be worth more than the sum of the value of its two component entities. Redundant lines of business are discarded and complementary ones are usually combined to benefit from network effects. Finally, with external growth this does not have to a full acquisition from the beginning. A stepped or staged investment can be undertaken more easily than with operational investments. Stakes taken can be further sold later if they end up proving unattractive or not corresponding to the strategy of the owner.

Moreover, we surveyed corporate divestments. There are several reasons for that. First, they are one way among others (use of cash flows from operations, corporate borrowing and project finance) to finance future growth. Second, they reflect one aspect of corporate strategies and public policies implementation, namely the shifting away from some lines of business or at least exposure reduction. Third, that is one way for us to track the disposal of carbon emitting or ageing fossil-fuelled generation. We also analysed the impact of swap / exchange deals as they became more frequent these past few years.

Beyond merely providing an analysis of the empirical results, we will ask ourselves what is the impact (both incidental and voluntary) of external growth investments on the ETS profile of the European utilities under scrutiny. Have the changes of ownership altered the EU ETS compliance perimeter of the utilities? To whom have carbon-emitting installations be sold to? Has there been carbon leakage in power generation? To what extent have Kyoto project mechanisms oriented financial investment decisions?

First, we will look at our data sample in more details to evaluate the type of information available and the weight thereof. Second, we will discuss the major trends in power plant operating decisions: the commissioning of gas-fired and renewables generation over 2004-2009 and the planned pipeline of generation capacity from 2010. Third, we will discuss trends in financial investments trends, namely expansion in the East, acquisition of renewables pure players, major M&A moves as well as the move towards regional energy utility and the weight of regulatory and contractual obligations. Fourth, we will analyse the impact of operating and financial investments on the ETS profile of the surveyed companies. In particular, we will assess the potential locked-in carbon emissions, the difficulty of measuring emissions reduction in this respect, changes in ETS compliance perimeter and specific developments related to the ETS (project mechanisms, carbon leakage, generation projects' cancellations and delays).

2.1 Data collection and analysis

In this section, we provide a description of alternative data sources for detailed corporate investment monitoring and how we classified collected data from the five utilities.

2.1.1 Data sources and collection

As outline in preamble, obtaining reliable and official data about investments in generation capacity can be tedious. First, we tried to stick to official releases from European utilities as much as possible even though there is no official consolidated source and there is often little mandatory and useful information. These official announcements come in three forms:

- Disclosures which are mandatory to comply with accounting standards (IAS or national GAAP): these disclosure are usually common to the sample of European firms but their content is often very limited and might be flexible as regards acceptable accounting practices;

- Disclosures which are mandatory to comply with the law (especially regarding EU-wide energy regulations): Security of Electricity Directive, Third Energy Package, the Euratom Treaty and Regulation EC 736/96 draft;

- Voluntary disclosures on the part of the sample firms (in the Management Discussion & Analysis section, in corporate news releases, etc.). These disclosures can be critical to a proper assessment even though they lack uniformity within the sample of firms and over time, they are not subject to disclosure guidelines and they are not audited or verified by any an independent third party. Furthermore, we could easily imagine firms boasting over pet R&D projects and playing down disclosures regarding investment in a carbon-intensive power plants;

Second, when the information was insufficient in official releases, we turned to third-party information for guidance, verification or investment project disclosure. We identified entities that publicly disclosed their information regarding investments undertaken by European utilities in generation like national regulators, umbrella organizations or independent market observers[2] and entities that had developed similar databases either accessible for a fee[3] or entirely proprietary for strategic planning purposes. Finally, when the information was of questionable quality, we either crossed the investment project out of the database or used a proxy, in which case we justified our choice on an individual basis.

We collected as much data as possible from the official corporate literature (annual reports, financial reports, etc.), press releases, investors communications from the companies websites for EDF ([33], [37], [38], [39] and [40]) and RWE ([30]), E.ON ([41], [42], [43] and [35]), Enel ([44], [45], [46] and [45]) and Vattenfall ([47]).

2.1.2 Scope and analysis retained

The five utilities surveyed are the most carbon-emitting utilities covered by the EU ETS according to the annual Carbon Factor report by PricewaterhouseCoopers (2009 [48]): 138 MtCO2 for RWE group in 2008, 100 MtCO2 for E.ON, 90 MtCO2 for EDF, 83 MtCO2 for Enel and 73 MtCO2 for Vattenfall. Overall, they have emitted 484 MtCO2 in 2008, which is equivalent to more than one quarter of the corresponding annual EU ETS cap.

Nowadays, the utility groups studied are integrated energy players involved along the whole value chain (production, transmission, distribution and sales) for both power and natural gas (to the exception of Vattenfall for the latter). Financial results aside, the groups assume leadership in one or

[2] In this respect www.power-technology.com and www.zeroco2.no proved to be reliable and useful sources of information.

[3] Argus, Platts and Nexgen databases for instance.

several areas. They typically rank among the top five groups at the European level on the basis of several criteria (installed capacity, international presence, market share, number of customers, etc.). Furthermore, these five groups operate under various names and own at least partially several other entities. The major ones are Endesa in Spain (owned at 92.06% by Enel), SE in Slovakia (5.4 GW of installed capacity - owned at 66.00% by Enel), EnBW in Germany (owned at 45.81% by EDF) and Edison in Italy (owned at 50.00% by EDF).

There is a need to monitor both internal and external sources of growth as can be seen by looking at the changing structure of capital expenditures (i.e. net financial acquisition plus operating capital expenditures) of two of the sample companies, RWE and E.ON[4], over 2004-2009 (see Table 2.1).

Table 2.1: Capital expenditures for RWE and E.ON - in EUR million

	2004	2005	2006	2007	2008	2009
RWE	3,737	4,143	4,728	4,227	5,693	15,637
- of which generation PP&E	22%	28%	53%	79%	66%	33%
- of which financial investment	8%	11%	5%	4%	22%	62%
E.ON	5,109	3,941	5,037	11,306	18,406	9,200
- of which generation PP&E	44%	62%	49%	43%	27%	70%
- of which financial investment	30%	27%	9%	40%	44%	6%

Operating investment

First, we consider operating investments in generation undertaken by the top 5 European utilities over the 2004-2009 reporting period within the EU ETS area (EU27 and Norway)[5]. Operating investments outside Europe and the Pan-European area are excluded even though significant investments have been undertaken (in the US notably). Unrelated investments are also excluded especially those in adaptation to climate change. The time step chosen is annual and follows the reporting calendar of the firms. We consider both brand new operating investments (greenfield) and modifications to already-existing investments (brownfield) such as power plant repowering or refurbishing. We acknowledge that investment completion status are to be accounted for and adopt the following classification: (1) in development (grouping the "announcement / planning" and "licensing process", sub-categories), i.e. operating projects which can rather easily be cancelled or postponed, (2) in construction and (3) commissioned.

[4]In addition to the data in the table, there has been asset swaps for E.ON discussed later in this chapter valued at EUR 4.4 billion in 2008 and EUR 2.8 billion in 2009.

[5]The focus on the top five utilities based on any size-related criteria excludes *de facto* smaller entities which might pursue alternative investment strategies.

Second, we track a project from the planning decision to its commissioning and gather as much economic and technical data along the way. In particular, we gather data (when available) regarding (1) technological data like type of technology used, capacity, load factor and emissions factor, (2) power plant sitting data: country and area, (3) financial data including total and interim cost, (4) investment timing like announcement date, scheduled vs. realised construction and commissioning and (5) any additional relevant data.

We will highlight timing, technology and geographical operating investment trends in this section. In particular, we relate investment decisions, delays and challenges to investment making in the light of various contemporaneous factors: (1) Global and EU-wide drivers (technologies, economic activity and policies), (2) Member state drivers (policies, power and carbon market design, EU ETS data) and (3) Utilities-specific drivers (financial data, strategic considerations and existing generation mix).

Financial investment

We surveyed six years of corporate investment decisions based on official documents from RWE, E.ON, Enel, EDF and Vattenfall. We collected data on financial investments in annual reports, financial statements, 20-F reports[6], sustainable development reports, corporate news and investors' communications. On rare occasions, we used industry estimates of transaction value in our database to better observe market investment trends. Our main data source was typically reported in the non-PP&E capital expenditures section of financial statements labelled financial acquisitions, assets or investments[7].

The corporate operations identified cover three main kind of deals:

- **Divestment** in a target entity ranging from a minority stake being sold to a disposal of the target. Unless indicated otherwise, the divestment entails receiving cash;
- **Exchange or swap** of various assets between two energy groups including (1) stakes in entities, (2) asset carve-outs (like power plants), (3) contractual capacity (procurement or drawing rights) and (4) cash for the valuation differential between the two legs of the swap;
- **Investment** in a target entity ranging from a minority stake taken to a complete acquisition of the target. Unless indicated otherwise, the investment is paid in cash.

[6] Available whenever European firms issued American Depositary Receipts (ADRs) to attract US investors.

[7] We excluded negligible financial investments in unrelated business to invest excess cash balance and money set aside and invested for pensions or other provisions for instance.

Compared to operating investments, we covered a larger scope (outside Europe and power generation), in order to highlight investments trends and structural changes within the European power sector.

Whenever available, we collected data regarding (1) the entities involved on both sides of the transactions (parent companies or subsidiary and nature of the entity), (2) the target (name, scope of activities, underlying existing and expected capacity, location), (3) percentage change in ownership, (4) the settlement of the operation (cash paid, assets tendered, etc.) and (5) motivation for the operation (if disclosed).

2.2 Trends in operating investment decisions

We recorded 254 power generation operating investments in Europe and pan-European area over 2004-2009. Among these investments, we identified 111 investments completed before 2010 (i.e. power plant commissioned) accounting for 13.6 GW and 143 power generation projects (planned, during the permitting process or in construction) accounting for 92.3 GW[8]. We excluded R&D investment (except CCS pilot plants and renewables) and the recommissioning of mothballed units. We considered both greenfield investment, that is power plants being built on new sites, and brownfield investment, namely power plants being built on existing sites being pure additions or in replacement of ageing generation.

Among generation projects commissioned between 2004 and 2009 (see pie charts in Figure 2.1), the bulk of projects was comprised of renewables (70% of the commissioned projects for 35% of generation capacity, i.e. 4.8 GW) and gas-fired (21% of the commissioned projects for 58% of added generation capacity, i.e. 7.9 GW) generation.

Among generation projects planned to be commissioned starting 2010 (see pie charts in Figure 2.2), the picture looks more diversified with more fossil fuel-fired and nuclear generation. Coal- and lignite-fired generation ranks first in added generation capacity (+ 28.7 GW, i.e. 31% of projected additional generation) and represents 18% of new generation projects. Gas-fired generation comes second in added generation capacity (+ 26.7 GW, i.e. 29% of projected additional generation) and represents 26% of new generation projects. Renewables account for 35% of announced generation projects that would represent 13.0 GW (14% of projected additional generation). Finally, nuclear generation projects would bring 15.6 GW online (17% of projected additional generation and 6% of the generation projects).

[8]Three officially cancelled generation projects are also in the database.

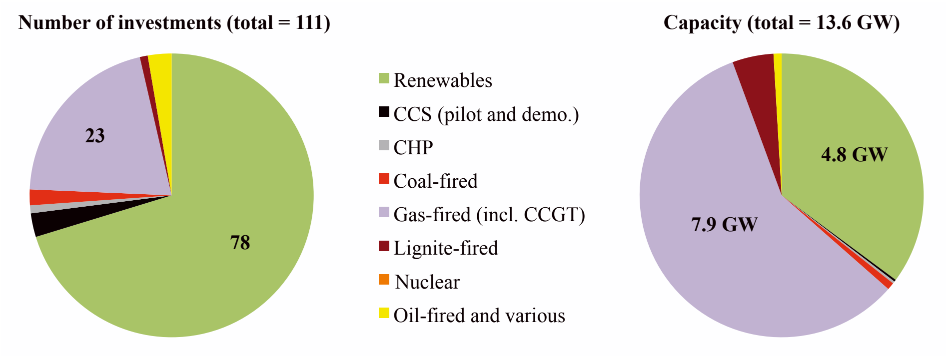

Figure 2.1: Number and underlying capacity of commissioned generation projects

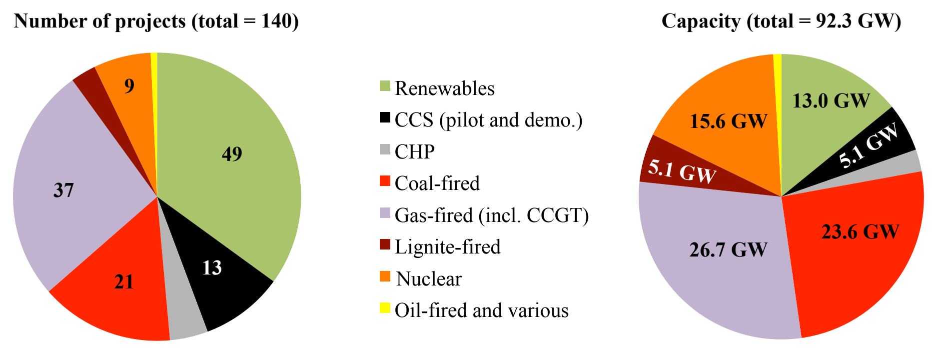

Figure 2.2: Number and underlying capacity of projected operating investments

We traced 254 investment overall with 54 for E.ON, 46 for EDF, 56 for Enel, 56 for RWE and 42 for Vattenfall (see Table 2.2)[9].

Table 2.2: Generation operating investment classified by group

Operation	E.ON	EDF	Enel	RWE	Vattenfall	Total
Realised	11	28	31	26	15	111
Projected	43	18	25	30	27	143
Total	54	46	56	56	42	254

Geographically, the projects spreads out throughout Europe (see Figures 2.3 and 2.4).

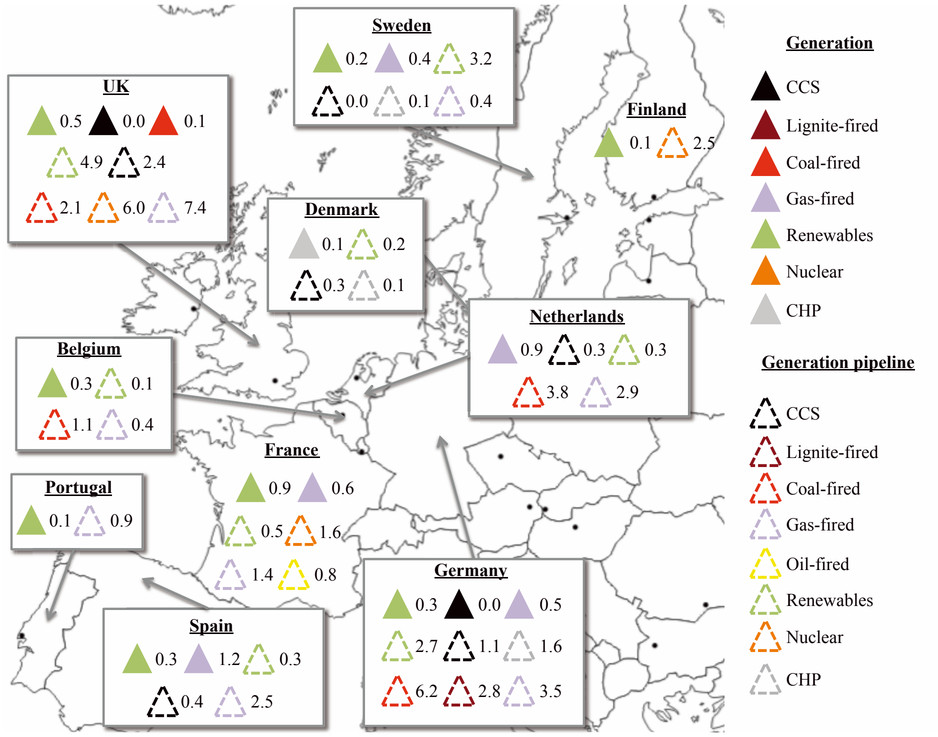

Figure 2.3: Location of European and pan-European additional commissioned and planned generation (1/2) - in GW

2.2.1 Additional generation over 2004-2009

We now look at additional generation that was commissioned over 2004-2009. The major investment trends have been in the field of renewables and

[9]Whenever there existed joint nuclear and renewables projects, we attributed energy group ownership to a single group to avoid double-counting on the basis of available information.

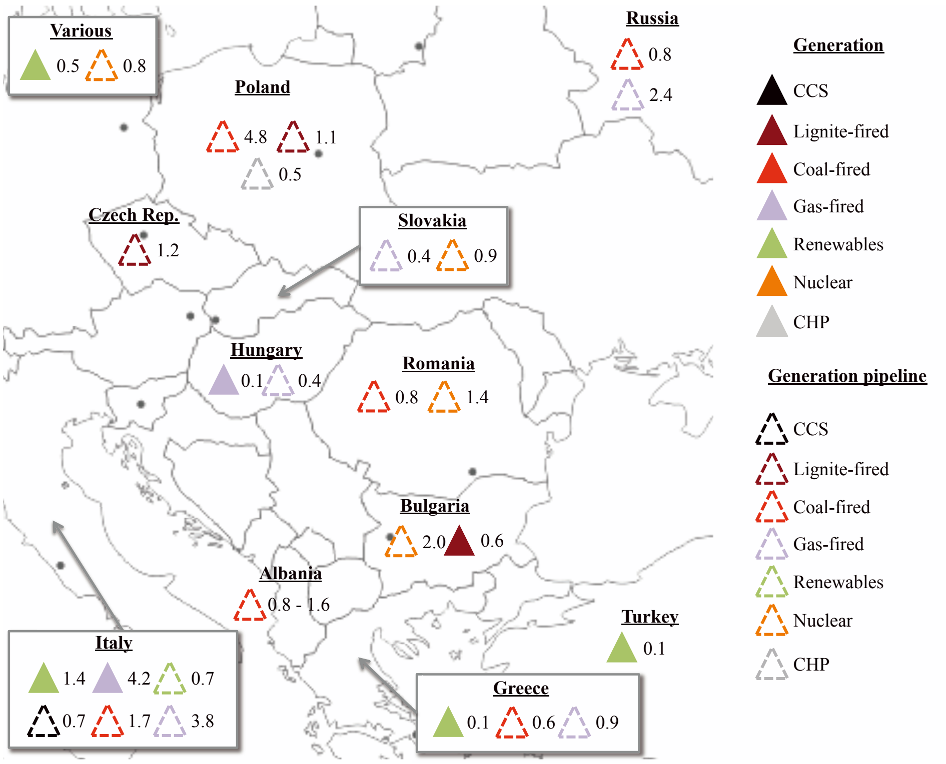

Figure 2.4: Location of European and pan-European additional commissioned and planned generation (2/2) - in GW

gas-fired generation.

Renewables

Most of the additional capacity based on renewables energy sources commissioned over 2004-2009 (4.8 GW) was wind-generated (3.3 GW). More than 44 projects of various scales contributed to that addition. Two large-scale wind projects particularly contributed to this amount: C-Power offshore wind park in Belgium for 300 MW (EDF Energies Nouvelles) and Ventominho onshore wind farm in Portugal (EDF Energies Nouvelles) for 240 MW. France, Italy and the UK attracted 56% of this additional generation capacity.

Over our sampling period, 624 MW of biomass- and waste-fired generation capacity was brought into service. This reflected two changes. On the one hand, some existing fossil fuel-fired power plants were converted to biomass-firing[10] for 371 MW. On the other hand, brand new installations were also

[10] By installing among others fluid bed combustion technology.

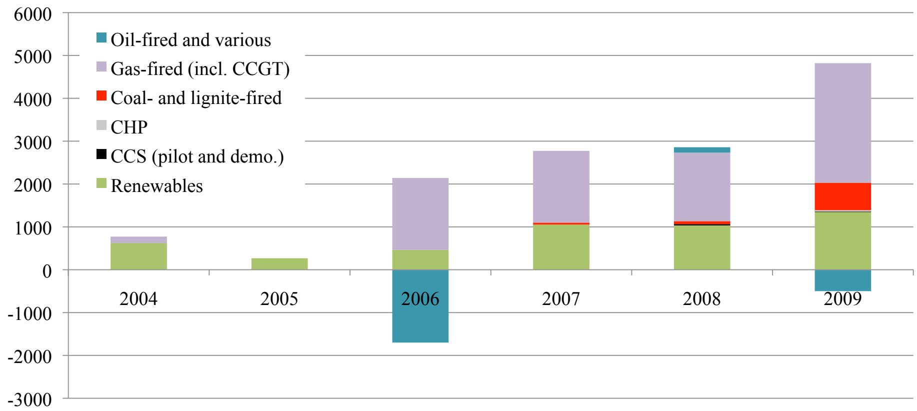

Figure 2.5: Additional generation over 2004-2009 - in MW

added to the overall capacity (+ 253 MW).

Finally, at least 389 MW of additional hydro capacity was added over 2004-2009 (59% of which in Italy and 35% of which in Germany). The remaining additional 460 MW include 53 MW of geothermal capacity in Italy, 226 MW of solar capacity (mainly in Western Europe) and a hydrogen installation with a 12 MW capacity.

Gas-fired generation

Approximately 7.9 GW of gas-fired generation was commissioned over the six years of the sample period, of which 6.8 GW was clearly labelled CCGT[11]. Most of the additional gas-fired generation put into service over the period was in Italy, Spain and the Netherlands. Two major trends occurred over the period.

First, 6.7 GW of greenfield gas-fired generation was commissioned. Flagship projects with high thermal efficiency (above 55%) were commissioned. For an identical MWh generated, less fossil fuel is fired with a high thermal efficiency compared to a lower thermal efficiency, hence a lower emissions potential. Such projects include E.ON's Livorno Ferraris 800 MW CCGT in Italy (thermal efficiency at 58%) and Edison's Sloe 870 MW in the Netherlands[12].

Second, a net amount of 1.2 GW of brownfield gas-fired generation was

[11]The remainder being either conventional gas turbines or unidentified CCGTs.
[12]EDF group.

commissioned[13]. This reflected various types of investments: (1) efficiency improvements, (2) changes in the main fuel used (conversion of oil-fired units to CCGTs in Italy) and (3) repowering (capacity increase without decommissioning of older capacity). For instance, unit 3 and 4 of Porto Corsini were converted from oil (750 MW) to gas (800 MW CCGT) yielding a 50 MW net increase in generating capacity and an emissions factor reduction for the 750 MW being replaced.

What motivated these trends was part environmental upgrade requirement for ageing generation (propelled by the entry into force of the large combustion plant directive, national requirements and corporate pledges to a lower extent) and part because of the cost profile of new CCGTs (relatively low upfront investment cost and short construction time).

Coal- and lignite-fired generation

Brownfield investment on RWE-owned coal-fired generation added 114 MW with higher thermal efficiency (38.9% instead of 36.5%). Additionally, the re-entry into operation of the fourth and final unit of Maritza East III (Enel) in Bulgaria brought back 880 MW of lignite-fired generation available after an environmental retrofitting and a life extension.

The first CCS pilot plants were commissioned in Europe over 2004-2009: RWE's Schwarze Pumpe (30 MW oxyfuel) and E.ON's pilot plants in Staudinger (1 MW post-combustion) and Ratcliffe (1 MW oxyfuel).

Additionally, over the sample period, various ageing fossil-fuel generation capacity or not meeting environmental requirements were decommissioned (minus 2.2 GW) as can be seen on Figure 2.5 (negative amounts in 2006 and 2009).

2.2.2 Operating generation projects

After having analysed operating investments that have been commissioned over 2004-2009, we now look at investment projects that have been announced over 2004-2009 and are expected to be commissioned from 2010 (see Figure 2.6).

[13] A relevant measure for brownfield projects is to consider the net capacity being equal to the new capacity put into service minus the old capacity that is being decommissioned (if any). Nevertheless, we were not always able to obtain the net amounts directly and had to estimate them for some projects.

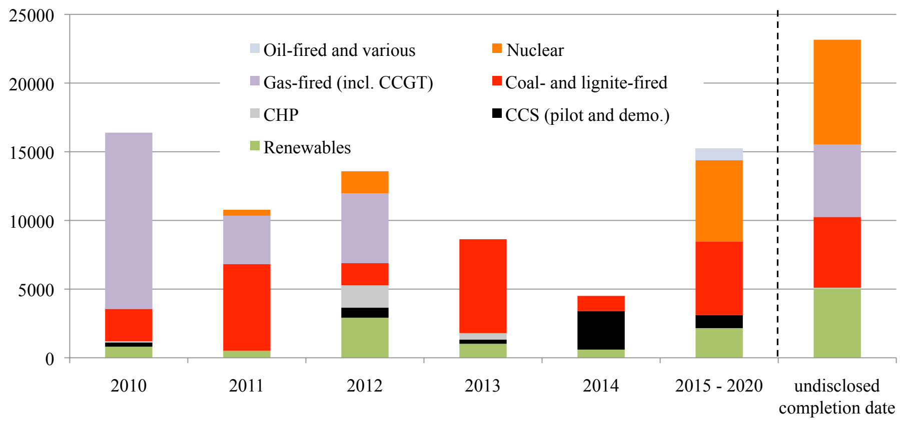

Figure 2.6: Additional generation projects from 2010 - in MW

Coal-, lignite-fired and CCS generation

33.8 GW of lignite- and coal-fired (with and without CCS) generation capacity is planned starting 2010 in Europe and Pan-European area by the five most carbon-constrained European utilities. Coal-fired without CCS[14] capacity accounts for 23.6 GW, CCS pilot and demonstration units accounts for 5.1 GW and 5.1 GW of lignite-fired capacity is planned. The projects are located mostly in Germany, the Netherlands, the UK, Italy and the Balkans (see Figures 2.3 and 2.4).

Planned coal-fired capacity is mostly comprised of large greenfield projects (above 800 MW) or extensions thereof. 39% of these projects are already in construction mainly in Germany and the Netherlands. The largest units typically feature high thermal efficiencies (above 45%): 1,530 MW in Hamm (Germany) and 1,100 MW in Maasvlakte 3 (Netherlands) with a thermal efficiency above 46% for instance or a 50% thermal efficiency for E.ON's 550 MW Wilhemshaven project in Germany. In order to further reduce emissions some of these power plants allow for biomass co-firing (up to 10% for RWE's 1,530 MW project in Eemshaven in the Netherlands). As regards brownfield projects, for the same reasons as gas-fired units revamping over 2004-2009, former oil-fired generation gets converted to coal in Italy (where 2,640 MW of oil-fired generation in Porto Tolle is being replaced by 1,980 MW of coal-fired generation).

2.8 GW of lignite-fired projects is under construction in Germany: BoA Neurath for RWE and Boxberg 2 for Vattenfall. Relatively high thermal ef-

[14] Including nonetheless CCS-ready generation.

ficiency lowered the plants' emissions factor to 0.95 tCO2/MWh and 0.924 tCO2/MWh respectively. In the former case this reportedly improved the emissions factor from 1.35 tCO2/MWh. In the latter case, the power plant commissioning required the recommissioning of an open-cast lignite mine nearby. In addition to that, 1.1 GW of lignite-fired generation is planned in Poland and 1.2 GW in the Czech Republic.

Among the 5.1 GW of planned CCS generation capacity, 47.5 MW are pilot plants and the remaining planned capacity are larger-scale demonstration plants. Almost 300 MW is planned in 2010, 730 MW in 2012, 300 MW in 2013, 2.8 GW in 2014 and 955 MW in 2015. It should be stressed that apart from the pilot projects, most of the CCS investments are either only planned or at early stages in the development process (permitting process, etc.). Therefore, there is a risk that CCS projects could be delayed or cancelled, as was the case in 2009 for two projects in which Vattenfall was involved.

Gas-fired and other thermal generation

26.7 GW of gas-fired generation is planned starting 2010. Again efficiency improvements (typically above 58%) both in greenfield and brownfield projects have a strong role to play. On a European scale, projects are more evenly spread over member states even though some countries typically attracts more gas-fired generation thanks to their energy mixes (7.4 GW in the UK and 3.8 GW in Italy notably).

In the UK and in the Netherlands, CCGT generation is scheduled to replace coal-fired generation (emissions factor of about 0.35 tCO2/MWh instead of 0.75 tCO2/MWh for an equivalent capacity). 48% of identified gas-fired generation is already in construction and expected to be commissioned before 2013. 3.4 GW of other fossil fuel-fired generation capacity (mainly CHP but also oil-fired or unidentified main fuel) is planned.

Nuclear generation

In the years of rebirth of nuclear power generation on a global scale, 15.6 GW of additional nuclear power generation were planned in Europe, 3.7 GW of which already in construction. This amount includes (1) EDF's 1,660 MW Flammanville nuclear plant in France, (2) major ongoing repowering efforts throughout Europe by Vattenfall (for 750 MW), (3) Mochovce unit 3 and 4 in Slovakia (for 880 MW) by Enel and (4) Oskarshamm 2 in which E.ON has a stake amounting to 430 MW. The remaining is planned capacity and includes projects in the UK (following UK's Nuclear Decommissioning Authority land sites auctions), in Finland, in Bugaria and Romania.

Renewables

As regards projects in the field of renewables, wind generation almost entirely contribute to the additional capacity (12.5 GW compared to a total of 13.0 GW). This amount includes (1) groups of projects at various stages in company's pipelines, (2) large offshore wind parks for at least 10 GW (including E.ON's share in London Array for 1 GW and RWE Innogy Nordsee project for 960 MW for instance) and (3) some onshore wind farms. Given the overwhelming weight given to offshore wind, most of the projects are naturally located on the Baltic sea, the North Sea or the Irish sea (areas gifted with good wind potential). The remainder of projected renewable generation that was announced is comprised of hydroelectricity (166 MW), biomass and waste (290 MW), solar (30 MW) and wave (20 MW).

On the basis of planned operating generation by the five utilities in our sample, we observe that almost two-thirds of planned generation is fossil fuel-fired, the remaining third being comprised of nuclear, renewables and CCS. Beyond this static observation, much of the coal-fired and gas-fired generation can nonetheless be retrofitted with CCS later, benefit from efficiency improvements or allow for biomass co-firing.

2.3 Trends in financial investment decisions

In this section, we present the result of the survey of financial investments (investments, divestments and swaps) for the top five carbon-emitting European utilities over 2004-2009. We echo the alternative taken by several European utilities to comply with the EU ETS constraint. We identified 336 corporate operations over the sampling period 2004-2009 for the five energy groups considered (see Table 2.3). On average, we identified nearly

Table 2.3: Financial operations classified by year

Operation	2004	2005	2006	2007	2008	2009	Total
Divestment	26	25	31	11	15	19	127
Swap			4	2	3	6	15
Investment	19	29	33	30	41	42	194
Total	45	54	68	43	59	67	336

22 divestments on an annual basis. Divestments occurred a bit more between 2004 and 2006 in preparation for subsequent major M&A deals and attempts thereof. Over the whole sampling period, we recorded 15 swaps. We identified approximately 32 investments per annum, except in 2004 were we recorded only 19 investments. We identified 101 transactions for Enel, 79 for EDF, 60 for Vattenfall, 57 for E.ON and 39 for RWE (see Table 2.4).

Table 2.4: Financial operations classified by group

Operation	E.ON	EDF	Enel	RWE	Vattenfall	Total
Divestment	19	32	32	14	30	127
Swap	6	6	2		1	15
Investment	32	41	67	25	29	194
Total	57	79	101	39	60	336

Clearly, the sample seems a bit unbalanced among the five energy groups. There are several reasons to this. First, the financial reporting policy has a clear role to play in the composition of our sample. The energy groups are and have been over time subject to various reporting requirements (shift from national GAAP to IFRS notably) or have engaged in different accounting treatment for similar economic operations. Furthermore, the quality of the information available depends on the investor relations' policy towards more or less transparency. For instance, some deals or details thereof are strictly confidential. This can be partially explained by the shareholder base information requirements and composition (states, institutional investors, individual shareholders, etc.). Additionally, the materiality of the underlying financial operations (no reporting for transactions below a certain value) or the practice of grouping similar transactions over a same reporting period (thereby reducing the number of observations - especially common for onshore wind and solar PV pipelines) affected the composition of our sample. Second, the differences in the reported transactions are indicative of genuine differences in the strategies employed and internal requirement. Sometimes this could indicate a preference for investment in PP&E over financial transactions or a need to reduce the weight of debt accumulated over the past years. Third, the nature of the deal is important. In the case of staged investments (additional stakes over time) and deals that trigger a flurry of operations (mandatory disposals for approval of a major deal, swaps, etc.), the number of operations increases quickly.

Nevertheless, this should not prevent us from identifying the major traits of the last few years among top emitting European energy groups. Acknowledging different practices among the energy groups, we turn to the analysis of the sample.

2.3.1 Financial investments trends

Over our sampling period, we estimate that the five energy groups under scrutiny invested at least EUR 112.7 billion in external growth. This figure is clearly a lower bound as for several transactions the amount was not disclosed[15].

As depicted in Figure 2.7, the investment aggregate amount evolved a lot over the sampling period. This nonetheless reflects a trend towards several major deals (over EUR 1 billion indicated in orange). The range for aggregate individual transactions below EUR 1 billion evolves between EUR 1.5 billion in 2004 and EUR 4.6 billion in 2008.

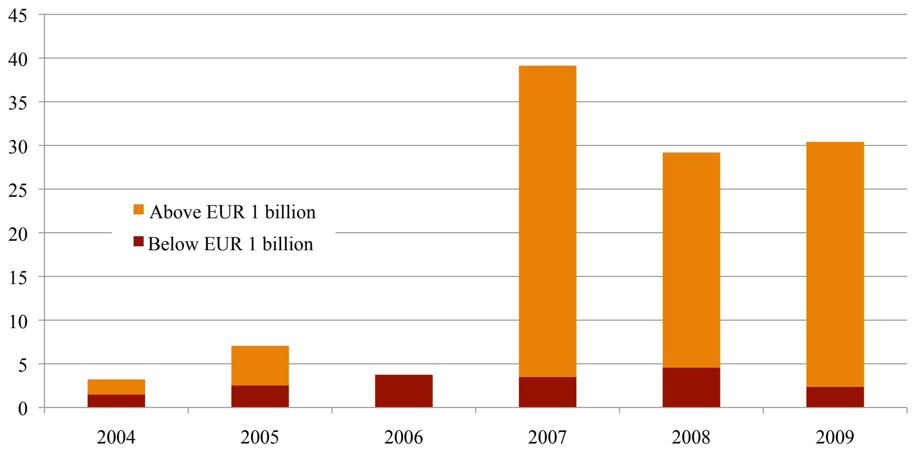

Figure 2.7: Financial investment amount - in EUR billion

We identified 19 investment operations in 2004 accounting for more underlying targets (multiple similar acquisitions bundled in reporting information). These operations amounted to more than EUR 3.2 billion. Investment rather catered to existing markets with a slight opening to Central and Eastern Europe. In 2005, 29 investments were accounted for, which cost more than EUR 7.1 billion to our sample groups. Investment in Eastern Europe continued and conventional generation and upstream gas receive significant investment. In 2006, the reorientation continued. 33 investments were recorded. These operations amounted to more than EUR 3.7 billion.

Starting 2007, the impact of major transactions on the market can be felt substantially. In 2007, 28 investments were recorded for 23 deals (two major staged investments). These operations amounted to more than EUR 39 billion. Compared to 2006, this more-than-tenfold increase was driven by a major operation in Europe and two in Russia. More investment in renewables is to be accounted for as well. In 2008, 40 investments were recorded.

[15]Transaction amounts were unreported for one deal in 2004, five in 2005, seven in 2006 (including potentially important ones), two in 2007, three in 2008 and as high as thirteen deals in 2009.

These operations amounted to more than EUR 29.2 billion. In 2009, we recorded 41 investments amounting to more than EUR 30.4 billion. The top four investments in 2009 were linked to major M&A moves.

We will therefore discuss the following investment trends[16]:

- Major deals (83.8% of the investments, defining a major deal as a transaction whose amount is above EUR 1 billion);
- Eastern Europe (11.0% of the investments);
- Renewables (45.5% of the investment - in value - featured "renewables");
- Other investment themes like conventional generation or upstream gas and related infrastructures.

Major deals

Over the period, there has been many changes in the geographical deployment of the utility groups by means of major operations on foreign European markets (The UK and Benelux region mainly). These deals were clearly driven by market penetration objectives (to a lesser extent for the increased stake in Edison).

Clearly, the most important deal over our sampling period was the acquisition of Endesa by Enel. In 2007, the Spanish energy company Endesa was successful taken over by the Italian energy company Enel for EUR 26.8 billion (after a long process involving rival attempts by Gas Natural or E.ON). The Enel group thereby gains access to a power generation capacity close to 40 GW (with 60% of fossil-fuelled generation in Spain, a significant amount of nuclear capacity and also renewables). As a necessary condition to proceed with the acquisition, in 2008, E.ON purchased "Endesa Europe" carved-out assets for EUR 11.4 billion from Enel[17]. More than 12 GW of generation assets in France, Italy, Spain, Poland and Turkey are transferred to E.ON. In 2009, Enel purchased Acciona's minority stake in Endesa for EUR 11.1 billion. This further increased Enel's ownership of Endesa to 92%.

In the UK, EDF's takeover of British Energy in 2008 for EUR 13.2 billion

[16]The percentages do not sum to 100% as investments may cover various strategies, this is especially true for major deals. Moreover, it was difficult and most often impossible to value the investment in a specific asset (like hydro capacity) that was part of a larger deal. By default, we reported the aggregate transaction amount. This might overestimate the role of renewables for instance.

[17]Note that the amount is different from the disposal proceeds for Enel as the sale operation was jointly performed with Acciona who partnered with Enel for Endesa's takeover.

was the most significant deal in the UK energy business over the period. This deal effectively transfers some 10.6 GW of generation capacity (81% nuclear and 19% coal-fired) to EDF's subsidiary in the UK.

In the Benelux region, in 2005, a 35% stake in Elsam A/S (a Danish utility) was bought for EUR 1.1 billion by Vattenfall. Again, a large share of the capacity (72%) is based on carbon-emitting fuels (coal, oil and biomass). In 2009, the acquisition of Essent (Energy utility operating in Benelux) by RWE was finalised for EUR 7.3 billion. It is worth noting that one of the stated objectives was to improve RWE's CO2 balance, Essent's carbon intensity being much lower than RWE's (0.557 vs 0.796 tCO2/MWh). As a result, RWE acquired 3.6 GW of generating capacity composed of 49.6% of gas-fired, 32.5% of coal-fired and the remainder in renewables (wind, biomass and hydro). Also in Benelux in 2009, the acquisition of a 49% interest in Nuon Energie by Vattenfall for EUR 5.1 billion added some 4.1 GW of generation capacity (24% coal-fired, 30% CCGT, 41% gas-fired and wind for the remainder) in the consolidation scope of Vattenfall. The acquisition of the remaining 51% is planned.

In 2005, EDF increased its stake in Edison (Italian energy utility) reaching 52%. This was caused by the exercise of put options by Fiat Energia, the Tassara Group and Italian banks. This transaction cost EDF approximately EUR 3.4 billion. EDF subsequently exercised joint control over the Italian subsidiary with AEM. A large share of the capacity (79%) is based on oil, gas and coal.

Liberalised Eastern Europe and beyond

As indicated previously, the Central and Eastern Europe was a major recipient for investment from the five sample companies. The target countries were countries from the 2004 wave of EU enlargement (Poland, Slovakia, Hungary and Czech Republic), those from the wave of 2007 (Romania and Bulgaria), Albania, Turkey and Russia. Investment in these countries over 2004-2009 amounted to more than EUR 12.3 billion. Overall almost 24 GW of fossil fuel nominal generation capacity were transferred to the five major utilities.

There are several reasons for investing in this region. First, the GDP growth potential combined with ageing existing generation capacity makes it an attractive investment. Second, the countries are close to the utilities' historical markets. As such, it would be conceivable to build in these countries and import the power generated using interconnections. Third, some of those countries (1) are not subject to the flurry of EU policies targeting power generation activities, (2) have only been recently subject to it or (3) have benefited (or still are benefiting) of transitory regimes to ease the transition to it.

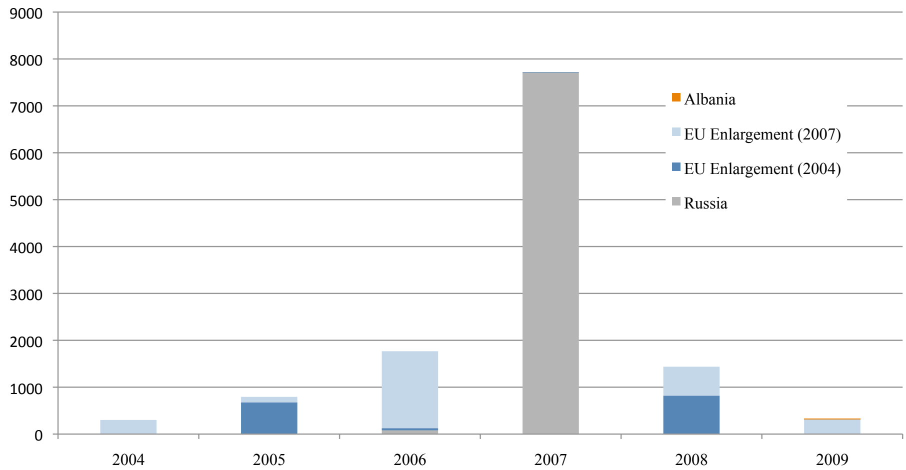

Figure 2.8: Financial investment in Eastern Europe and surrounding countries - in EUR million

Figure 2.8 covers investment amount in Eastern Europe and surrounding countries. The investment in Albania is for a project company at an early stage. Investment amounts for renewables in Turkey in 2008 and 2009 exist but were not disclosed and as such are not featured on the figure.

The map on Figure 2.9 indicates location and kind of investments in Eastern Europe and surrounding countries.

In 2004, the region attracted investment of more than EUR 302 million[18] in utilities whose range of activities involve coal-fired generation, power and gas distribution and sales (in Hungary, Czech Republic and Poland). National governments sold such stakes. In 2005, investment in power and gas distribution and sales activities in the region rose to EUR 794 million (from the Romanian, Bulgarian, Polish and Czech governments).

2006 saw a major deal in Eastern Europe with the acquisition of a majority stake in Slovakia's SE (utility) by Enel for EUR 840 million. The utility has a total net installed capacity of 6,356 MW (of which 38% is nuclear, 37% is hydroelectric and 25% is powered by coal and lignite). Moreover, 840 MW of lignite-fired generation in Bulgaria were acquired. In addition to that, the purchase of infrastructures, upstream and downstream gas activities in

[18] Plus three transactions whose amount was undisclosed.

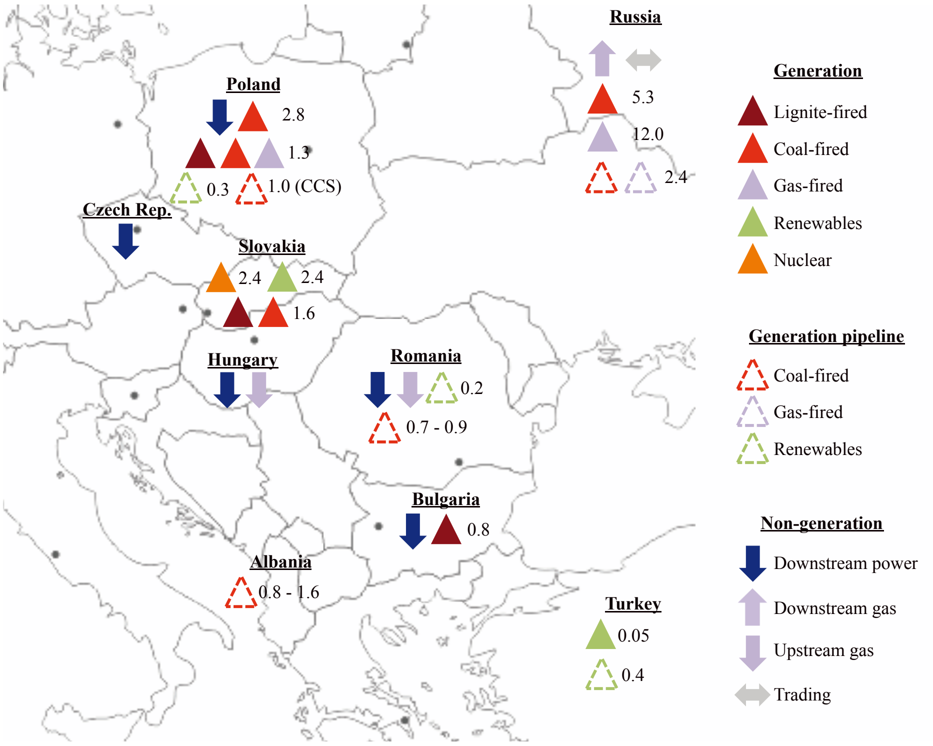

Figure 2.9: Financial investment in Eastern Europe and surrounding countries (capacity indicated in GW)

Hungary by E.ON Ruhrgas from MOL amounted to EUR 450 million. Excluding E.ON's investment in MOL's gas activities in Hungary, some EUR 1.3 billion has been invested in Central and Eastern Europe and Russia.

In 2007, more than EUR 7.7 billion was invested in Russia. First, the acquisition of a 73% stake in formerly Russian state-owned OGK-4 (power generation) by E.ON amounted to EUR 4.4 billion. E.ON thus became a majority stakeholder in the company with a net capacity of 8.6 GW, 83% gas-fired and 17% coal-fired. OGK-4 plans to add 2.4 GW of "technologically-advanced" generating capacity at existing sites by 2011. Second, we identified the purchase of 60% in formerly Russian state-owned OGK-5 (power generation) by Enel for EUR 2.6 billion. Enel now is a majority stakeholder in the company with a net capacity of nearly 8.7 GW, 56% gas-fired and 44% coal-fired. In addition to the two aforementioned major stakes in power generation, an upstream gas investment was made for EUR 770 million.

In Eastern Europe and Russia in 2008, more than EUR 1.4 billion was invested by the top five European carbon-emitting utilities. Four out of the seven deals feature fossil-fuelled generation. These investments also include preliminary developments for 800 to 1,600 MW of coal-based generation in a free trade area of Romania. On the other hand, ENEA in Poland (in which Vattenfall acquired a 19% stake in 2008) envisages a new 1,000 MW CCS-ready unit for 2015. A major acquisition that year was Enel obtaining a 64% stake in a power distribution and sales company, Electrica Muntenia Sud, in Romania for EUR 820 million (from the Romanian privatisation office).

In 2009, the five utilities invested more than EUR 1.4 billion in Eastern Europe, Russia and Turkey. The investments were primarily targeting power generation (roughly half coal-fired half renewables).

Acquisition of renewables capacity

There have been two main paths for external growth in renewables. On the one hand, some renewable capacity was acquired in the course of major deals. On the other hand, several projects (existing and planned) were acquired from pure players in the renewable generation market. Over our sampling period, we found that EUR 51.2 billion of the investment amount featured a renewable component. Still, this figure includes major acquisition like Endesa's. Based on our data, a lower bound estimate for investment in pure players and carved-out renewable generation would be EUR 4.4 billion.

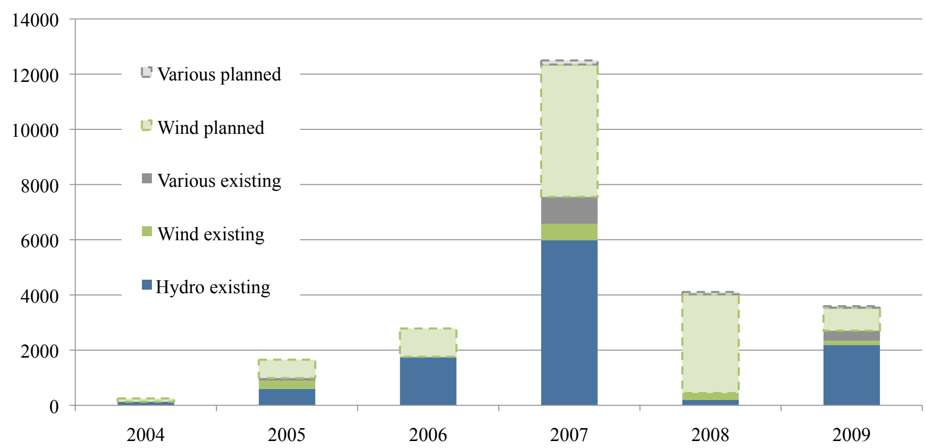

Figure 2.10: Additional attributable capacity - in MW

Figure 2.10 indicates the additional attributable capacity from investments in renewables over 2004-2009 (estimate over the period is 24.9 GW). This corresponds to the net generation capacity multiplied by the percentage change in ownership. That way, we have been able to reduce the impact of minority stakes taken in highly reputational projects.

Even excluding the impact of Endesa's acquisition (accounting for the bulk of additional hydro capacity for 2007 and 2009), we clearly see that the pace increased until 2007 and slowed down afterwards.

In 2004, attractive markets for renewables (Spain, Sweden and the US) were targeted (investment of EUR 79 million). Owners of renewables pure players benefited from these investments. In 2005, renewable generation investment attracted at least EUR 41 million[19] again in markets with favourable regulatory frameworks (Sweden, Germany, Greece, France and the US) from renewables pure players. In 2006, various stakes have been taken in generation based on renewables (hydroelectricity, wind & biomass mainly) for more than EUR 754 million in France, Northern Europe, Germany, and the Americas for nearly 1.7 GW of existing capacity and a pipeline of 2 GW. Putting Endesa's acquisition aside, more than EUR 2.1 billion was directed to renewables investments in 2007. In addition to the previously favoured countries, some investment was made in new destinations (Belgium and Romania for instance). These stakes were bought from various profiles (renewables pure players, private equity firms and diversified energy groups). An additional EUR 11 million was injected in offshore transmission dedicated entities in 2007. In 2008, EUR 1.2 billion have been spent in external growth towards renewables and in wind mainly (12 deals out of 15). These investments were performed in the typical areas for renewables (Northern Europe, the UK, Spain) but also in Italy, Greece and Turkey, where a partnership with local entity is usually set up. The year after, we recorded more than EUR 176 million invested in renewables (wind mainly) acquired from pure players essentially.

A major trait was the acquisition of renewables generation pipelines, wind most predominantly, rather than just existing assets (11.3 GW vs. 13.6 GW). On the one hand, this (1) entails subsequent cash injections over the lifetime of the investment, as the underlying project evolves along completion stages and (2) adds the risk that projects are not completed. On the other hand, it is a cheaper investment to begin with and it eases knowledge sharing with the parent company. Another characteristic was heavy reliance on hydro and wind. The various category (planned and existing) accounting for uncategorised investments and biomass, photovoltaic, geothermal and ocean wave, has a little role to play in the additional attributable capacity based on renewables (less than 7%).

[19] Transaction amounts from three out of five investments were not disclosed.

CCGT and fossil fuel projects

In addition to investment in renewables project, the period also saw investment in conventional fossil-fuelled generation (which was more geared towards CCGT nonetheless) slightly below EUR 1 billion. The total capacity of the underlying project amounts to 4.2 GW (2.4 GW existing and 1.8 GW in progress or planned) and the additional attributable capacity amounts to 2.7 GW.

In 2005, there was investment in CCGT capacity in the UK (812 MW for EUR 412 million). This additional capacity was bought from groups whose core business is not necessarily power generation. In 2006, majority stakes have been taken in conventional generation projects (CCGTs in the Netherlands and in Greece for 1.8 GW) amounting to small amounts given the early stage status. In existing target markets, CCGT power plants attracted EUR 58 million (capital increase and early stage investment in a project company) in Belgium and Greece in 2008. Related to conventional generation, one of the entities secured a 10% stake in one its coal supplier. In 2009, higher stakes have been taken in coal- and lignite-fired generation in Germany and complete acquisition of 1.1 GW of fuel oil and gas oil-fired generation in Ireland has been performed.

Upstream gas and related infrastructures

Another significant trend has been investment in upstream gas (exploration and production) and related infrastructures (pipelines, pipelines, etc.). Some EUR 3.7 billion have been invested between 2004 and 2009. These investments responds to security of supply concerns for downstream gas distribution and sales activities but also to secure fuel procurement for CCGT power plants.

In 2005, upstream gas and related infrastructures investment amounted to EUR 817 million for E.ON (gas field, storage and pipeline). This included the acquisition of Caledonia (a British company exploiting a gas field off the shores of the UK) from a private equity firm for EUR 602 million. In 2006, more than EUR 720 million was invested in upstream gas and related infrastructures (storage, pipeline, LNG regasification terminal) including the purchase of infrastructures, upstream and downstream gas activities in Hungary by E.ON Ruhrgas from MOL for EUR 450 million. In addition to the an upstream gas investment in Eastern Europe (for EUR 770 million), EUR 340 million was invested in LNG regasification (onboard ships and terminal in Italy) in 2007. In 2008, gas infrastructures (LNG regasification terminal and pipelines) attracted some EUR 281 million in Europe. In 2009, at least EUR 597 million was invested in gas fields in the UK, the Netherlands and

Egypt.

Other investments

Other significant trends include (1) power and gas distribution and sales investment in local or proximity markets and (2) EDF's nuclear generation focus.

In the first case, it is quite difficult to isolate this trend as downstream activities are a key component of the major deals that occurred over the period. We will therefore mention additional significant developments. In 2004, there was a move towards acquisition of electricity and gas distribution and sales activities for EUR 1.8 billion (including the acquisition of a British distribution company, Midlands Electricity, acquisition by E.ON UK for EUR 1.7 billion). In 2005, investment in power and gas distribution and sales activities in existing markets (Italy and the Netherlands) slowed down and amounted to EUR 102 million. In 2006, in existing markets, more than EUR 97 million was invested in local gas and power distribution and sales activities in Germany and Italy. In 2008, Enel obtained a 64% stake in a power distribution and sales company, Electrica Muntenia Sud, in Romania for EUR 820 million (from the Romanian privatisation office).

In the second case, British Energy's takeover (mainly nuclear generation) was a major step. In 2009, EUR 3.1 billion was spent by EDF for a 50% stake in nuclear activities in the US (3.9 GW) through its partnership with Constellation in 2009. As part of a strategy to focus on nuclear generation worldwide, EDF also took an additional 5% stake in its soon-to-be partner in nuclear generation in the US for EUR 412 million. There were also significant but uncategorised investments over the period, which we will not discuss.

2.3.2 Divestitures to fund capital expenditure plans

Figure 2.11 categorises divestments from the top five carbon-emitting European utilities over 2004-2009. Over this period, at least EUR 62.5 billion was generated from entities or assets disposal proceeds. The two main reasons why are strategic reorientations towards regional energy utilities (for 61%) and mandatory disposals for regulatory and contractual grounds (for 35%).

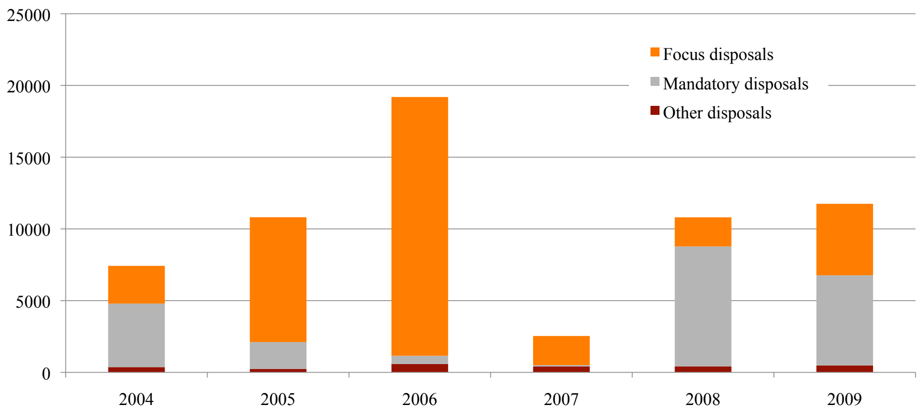

Figure 2.11: Financial divestment categories - in EUR million

Focus on the European energy business

The most significant trend in corporate divestitures over the period was the strategic reorientation from traditional multi-sector utilities operating sometimes on a global scale to regional energy-focused utilities. A necessary step was therefore the divestment of non-core business. Based on qualitative input from corporate communications, we were able to distinguish among three types of non-core business divestments: non-core activities, non-core markets and non-core services (internal services). Figure 2.12 presents an-

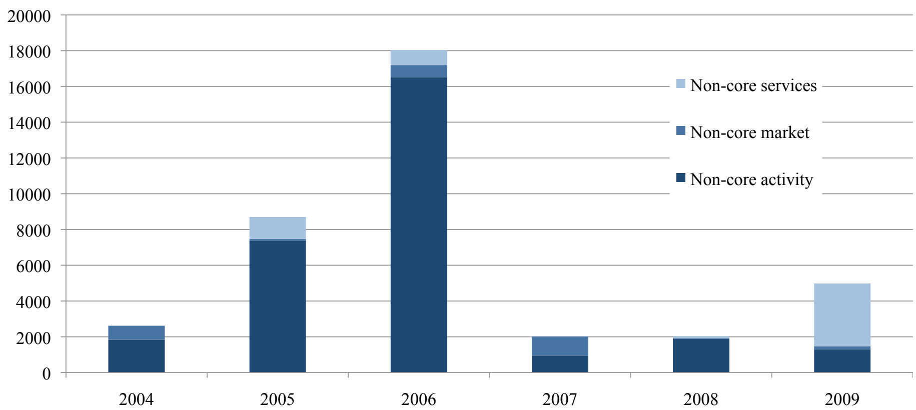

Figure 2.12: Financial divestment of non core entities - in EUR million

nual divestments categorised as such. The trend clearly indicates that the major divestitures occurred between 2004 and 2006, in part in preparation for the major investments that began in 2007. The bulk of related disposal was from non-core business segments (being the most valuable assets).

Non-core activities include all the remaining activities inherited from the multi-sector utility business model and former conglomerate activities. In 2004, at least EUR 1.8 billion (five unreported amounts remain) was generated by selling activities in the field of public transportations, telecom, waste management, industrial activities (chemical and cement) and retail activities (shoe-making). These activities have been sold to either industrial groups focusing on these activities or to financial institutions (banks, institutional investors, etc.). The disposal of Enel's real estate business (NewReal) was the largest disposal in 2004. Proceeds amounted to EUR 1.4 billion. The business was sold to a consortium of banks (Deutsche bank and CDC-IXIS). In 2005, some EUR 8.1 billion was generated from divesting non-core business (telecom, water, waste management, real estate but also vehicle leasing, printing business and IT), which was sold to relevant industrial groups. The major deals were (1) the sale of E.ON's real estate subsidiary (Viterra) to Deutsche Annington GmbH, a German real estate group, for EUR 4.0 billion and (2) the first stage of the disposal of Enel's telecom business (Wind) to businessman Naguib Sawiris for nearly EUR 3.0 billion.

In 2006, proceeds from non-core activities divestments more than doubled and amounted to EUR 16.5 billion. The disposed entities covered chemical activities, traditional utility companies activities (water, waste management and telecom) and real estate. A large share of those activities is being sold to infrastructure funds or financial investors rather than industrial groups. The three major operations were (1) the disposal of RWE's UK water business (Thames Water) to a consortium led by Macquarie's European Infrastructures Fund for EUR 11.9 billion, (2) the sale of E.ON's stake in Degussa (chemicals) to German industrial conglomerate RAG for EUR 2.8 billion and (3) proceeds from the sale of the additional stakes in Enel's telecom activities (Wind) for roughly EUR 1.4 billion.

Since 2007, proceeds from non-core activities contributed less to divestiture amounts given that most of the reorientation towards regional energy-focused utilities was achieved. In 2007, only EUR 604 million was obtained from the divestment of non-core business (telecom and waste management), which was sold to pure players, in particular the disposal of E.ON's telecom activities (ONE) to a consortium consisting of France Telecom and a private equity firm for EUR 569 million. In 2008, EUR 1.9 billion were obtained from the sale of non-core business (water and telecom): additional proceeds from the sale of Wind (Enel's former telecom business) for EUR 962 million and proceeds from the beginning of the sale of RWE's water business in the US. EUR 922 million have been generated in the course of an IPO for 40% of the outstanding shares. In 2009, a new IPO for American Water was organised in 2009 and RWE managed to sell its remaining 61% for EUR 1.3 billion.

Another part of the focus strategy was divestments from **non-core markets**, be they overseas or European. In 2004, our sample group divested generation activities from their non-core markets (China, Indonesia, Russia and Spain) for EUR 789 million. These activities were sold to local utilities willing to increase their generation base. In 2005, more than EUR 118 million[20] were obtained from selling power distribution and sales activities and generation assets from non-core regional markets (Portugal, Pakistan, Argentina, and the Netherlands) to local utilities and energy companies. In 2006, nearly EUR 676 million was generated by sale of power generation and distribution activities in non-core markets (Brazil, Colombia, Egypt, Argentina and Ireland). Unsurprisingly, these were sold to local players. In 2007, the sale of stakes in non-core markets (Mexico, Argentina, Kazakhstan, Latvia and Estonia) generated nearly EUR 1.1 billion. Activities sold on those markets were various (upstream oil, district heating, power generation and distribution) and transferred to local or regional groups. The largest operation was the sale of several CCGTs (2.2 GW) and a gas pipeline in Mexico by EDF to Gas Natural for EUR 951 million. In 2008, only EUR 43 million from non-core markets (50 MW of wind capacity in Morocco) were obtained. In 2009, RWE's sale of its water activities in the US and Enel's sale of a non-controlling stake in power and gas distribution and sales activities in Colombia (for EUR 172 million) were the main disposals that were part of a focus strategy for energy groups. In addition to that, Enel sold a 20% stake in its Russian upstream gas activities to Gazprom for EUR 670 million.

Finally, the last element of the focus strategy was the divestiture of **non-core services**, i.e. internal services / not customer-driven. In 2004, non-essential services activities (contracting, procurement, etc.) were sold for circa EUR 6.7 million. In 2005, our sample group of utilities also received more than EUR 1.2 billion from the sale of service-related activities (coal procurement, coal transport or engineering). The main operation was the sale of E.ON's Ruhrgas Industries (quality and engineering - gas measurement and control) to CVC Capital Partners, a private equity group, for an estimated amount of EUR 1.2 billion. In 2006, internal service activities were disposed of for EUR 842 million. These activities covered engineering activities (dismantling of industrial sites, power plant construction), coal mining and venture capital activities (for both EDF and Enel). In 2007, non-core internal services sold (coal mining and contracting) generated EUR 10 million. In 2008, we recorded EUR 103 million from disposals of internal engineering services.

[20] Proceeds from three out of five such divestments were unreported.

Regulation and contractual obligations

Apart from voluntary divestitures part of a reorientation strategy, the second most significant source of divestments was constrained divestiture. This happened because of:

- Regulation mandating disposals of assets: as a condition to approval of mergers and acquisitions for instance or as a necessary step for implementation of the liberalisation process of European energy markets (sale of transmission networks for instance);

- Regulation jeopardizing existing business ongoing profitability for various reasons;

- Contractual agreements entering into force (exercise of financial options, etc.) and post-deal adjustments.

Figure 2.13 categorizes motives for such investments. Post-deal adjustments and regulatory mandated disposals accounted for most of the divestitures over the period.

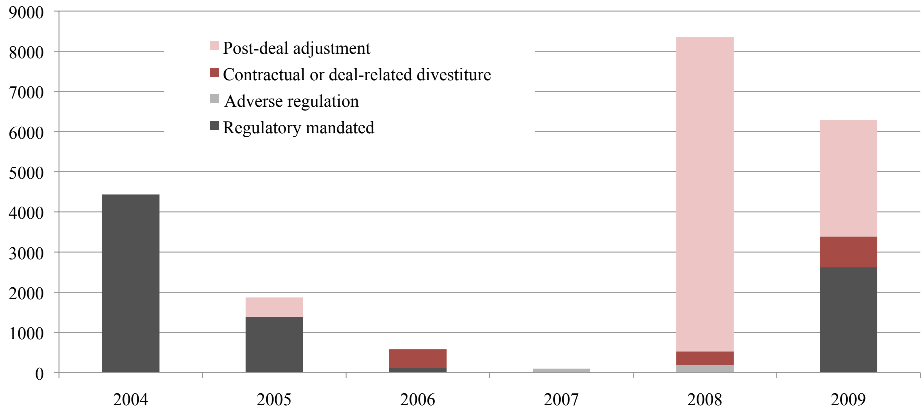

Figure 2.13: Mandatory financial divestment - in EUR million

In 2004, proceeds from this kind of disposal amounted to EUR 4.4 billion. One of the main operations was the sale of Terna (near totality of the Italian transmission grid) by Enel for circa EUR 3.0 billion to Cassa Depositi e Prestiti, an Italian partially state-owned bank (EUR 1.3 billion) for 30% of the shares and via an IPO (EUR 1.4 billion) for 50% of the shares. This divestment was required by prevailing regulation. 20% remains in the hands of Enel. Another significant disposal was the sale by the E.ON group of its entire 42.1% stake in VNG (gas transportation) to German utility EWE and German municipal authorities for EUR 0.9 billion. This disposal was a condition to ministerial approval of Ruhrgas acquisition back in 2003. In 2005, the sale of additional shares in Terna (Italian power transmission) and related dispatch assets by Enel for EUR 636 million accounted for the share of regulatory mandated disposal. In 2006, several divestments were also made compulsory for (1) regulatory reasons (transmission networks and power distribution in Italy) and (2) contractual reasons (exercise of call options on the part of buyers in particular). In those cases, the divested activities are probably still attractive to the energy groups but they are nonetheless required to proceed with the disposals. This type of disposal generated EUR 579 million. In particular, E.ON sold its entire stake in E.ON Finland to Fortum for EUR 390 million and Enel sold Union Fenosa a 30% stake in renewables pure player, Enel Union Fenosa Renovables (EUFR), for EUR 72 million. In the wake of the mandatory divestments, Enel sold further transmission assets (Enel Rete) to Rtl (a wholly-owned subsidiary of the Terna Group) for EUR 294 million.

In 2007, adverse regulations provoked sale of distribution activities in the Netherlands (RWE) and of CHP capacity in Italy (EDF via its Italian affiliate, Edison). RWE's disposal of its Dutch gas distribution activities to the city of Eindhoven amounted to EUR 400 million. The reason invoked is that Dutch regulations prevent RWE from expanding their grid activities in the Netherlands. In 2008, because of the Endesa takeover, divestments in order to conclude the deal took centre stage and generated EUR 7.8 billion (including the aforementioned major carve-out of Endesa Europe assets). EUR 7.1 billion for the sale of Endesa Europe assets to E.ON as part of Enel's acquisition of Endesa (and withdrawal of E.ON's minority stake). In Italy, further thermoelectric capacity was divested because of unfavourable conditions on the retail market (for EUR for 540 MW). In 2009, in target markets, regulatory authorities or negotiations (*ex post* or *ex ante*) on major deals imposed some divestments. These operations accounted for the bulk of the divestments (EUR 6.4 billion): (1) sale of stakes in Endesa's heritage assets for EUR 3.2 billion, (2) mandatory sale of a coal-fired plant in the UK following EDF's British Energy takeover for 370 million and (3) mandatory (or *ex post* adjustments) divestments in the transmission business in Germany and Italy for EUR 2.8 billion (sale of almost 100% of Thüga business in Germany, E.ON network of local utilities, to a consortium of municipal utilities for EUR 2.9 billion and the transfer of operational wind and hydroelectric assets in Spain and Portugal (2.1 GW) from Enel to Acciona group for EUR 2.9 billion[21]).

Other divestments

Motives for other divestments are various and include (1) changes in the scope of consolidation & sale of minority and non-controlling stakes for EUR

[21]Note that this was agreed-upon in the preparation of Endesa takeover by Enel.

732 million, (2) transfer of ownership of local assets to municipal entities for EUR 1.1 billion, (3) sale of gas infrastructures for EUR 176 million and uncategorised disposals.

Overall, we do not find that any of the disposal was predominantly motivated by the EU ETS in preparation for the launch of the carbon constraint in 2004, in phase I or at the beginning of the EU ETS. We will explore that in more details afterwards.

2.3.3 Swaps

The first major swap including power generation over our sampling period involved Vattenfall, Dong Energy and Energie E2 in 2006. According to the deal, Vattenfall would acquire 24% of the generation capacity of Elsam and Energie E2 (i.e. five coal- and gas-fired CHP power plant for 1.9 GW plus 500 MW of wind generation) in exchange for Vattenfall's recently acquired 35.3% ownership in Elsam (transferred to Dong) and Vattenfall's holding in Avedöre 2 (transferred to Energie E2). The deal required clearance by the EC and was quite instrumental to helping Vattenfall gain market shares in its core markets.

In the most recent years of our sample, E.ON pursued a strategy of consolidation of its ownership in subsidiaries by acquiring minority shareholding in exchange for various assets and holdings. In 2008, E.ON and Italian energy group A2A exchanged capacity in Italy. E.ON acquired the remaining 20% of former Endesa Italia from the minority shareholder in exchange for Montefalcone 980 MW coal-fired power plant in Italy and EUR 1.5 billion. In 2008 as well, E.ON consolidated its ownership in E.ON Swerige by acquiring the remaining 44.6% and a hydroelectric power plant in Sweden from Statkraft. In exchange, Statkraft obtained from E.ON: (1) shareholding in E.ON generation assets (40 hydro + 5 heating plants in Sweden, 2 gas-fired, 11 hydro, stakes in 2 biomass-fired, one structured gas supply contract and a power purchasing agreement in Germany and 1 hydro in the UK) and (2) circa 4% of E.ON stock. In order to acquire the remaining stake 35% in Snet and 800 MW of power procurement rights from nuclear assets in France, E.ON exchanged (1) 800 MW of nuclear power procurement in Germany, (2) 100% of its 50.4% in a coal-fired power station in Rostock and (3) power procurement rights from Buschhaus (coal-fired power station) with EnBW in 2009.

Other major swaps include EDF Energy's acquisition of Centrica's stake in SPE-Luminus in Belgium in exchange for existing and planned nuclear generation in the UK in 2009. SPE-Luminus is the second leading electricity producer in Belgium. The deal required asset disposal on the part of EDF.

2.4 Impact of operating and financial investments on ETS profile

In this section, we will discuss first the potential of locked-in carbon emissions from operating projects and the difficulties in evaluating whether the commissioned and planned investments are to be considered emissions reduction efforts (regardless of the EU ETS in this respect) or just brand new carbon emitting projects. Second, we will discuss the effect of financial transactions on the compliance perimeter of the most carbon-emitting European utilities. Finally, we discuss three specific areas in which the EU ETS has had a direct impact: carbon leakage potential in the Pan-European area, resort to Kyoto project mechanisms to expand operations in the East while reducing the EU ETS compliance cost and reportedly ETS-related delays and cancellations of generation projects.

2.4.1 Impact of operating investments on ETS profile

We computed a rough estimate of the locked-in carbon emissions from commissioned and planned carbon-emitting generation projects. Based on operating investments' available technical data (emissions factor, number of hours the plant would be running over a year and power plant net generation capacity) and assumptions for missing data (power plant expected lifetimes and missing technical data), we computed an estimate of the additional potentially locked-in carbon emissions from brownfield and greenfield generation projects (see Figure 2.14).

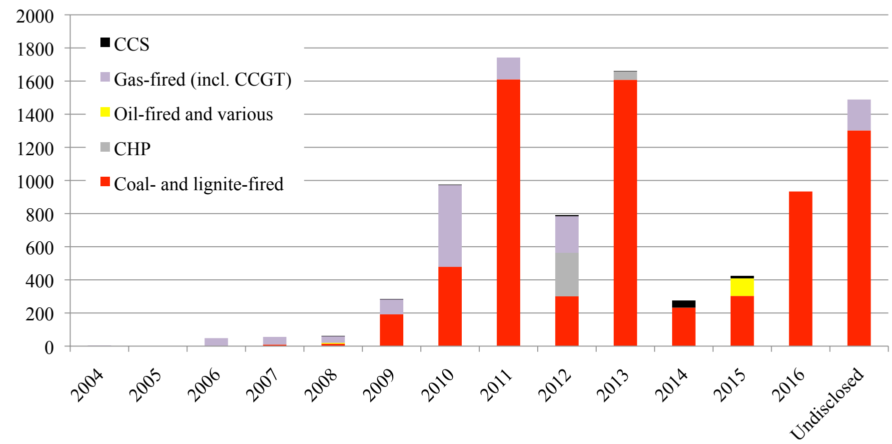

Figure 2.14: Additional potential lifetime carbon emissions - in MtCO2

In particular, we find that projects from our sample lock-in potential carbon emissions close to 8.7 $GtCO_2$ overall over their expected lifetime assuming no further retrofitting on the one hand and realisation of planned projects on the other hand. This is equivalent to almost six times the CO_2 emissions of the EU27 from power generation in 2007[22]. Commissioned projects over 2004-2009 accounts for 454 $MtCO_2$ while planned projects account for the large remaining amount. The numerous large-scale coal-fired and lignite-fired generation projects unsurprisingly contribute largely to this amount (nearly 80%). These are nonetheless natural candidates for CCS retrofitting all the more as new builds typically features high thermal efficiency to make up for the efficiency loss implied by carbon capture current techniques or are simply CCS-ready.

This is only one part of the story. Any new generation project satisfies part of the electricity demand and cannot be to blame on the sole basis of its carbon emissions potential. Obviously, it is hard to assess what corresponded to emissions reduction in all this as some benchmark or counter-factual investment pattern is to be defined. Brownfield investment could be readily compared with emissions from their former technical data. Most often, we see net improvements in terms of emissions reduction as brownfield investment was largely geared towards biomass co-firing and thermal efficiency improvement.

The picture gets blurrier when it comes to greenfield investment as it difficult to tag a specific investment as in favour of emissions reduction. In this respect, no investment at all is for the better but clearly this does not make sense. The issue of a proper counter-factual investment benchmark arises again. In the corporate literature we have analysed so far, European utilities often assess emissions reduction potential from projects by comparing emissions from the new project with those of an ageing coal-fired plant or with a gas-fired plant for renewables for instance. But this is just a convention that need not be realistic.

However, entirely attributing these changes to the ETS would be hasty as other policies (notably the large combustion plant directive), national and corporate energy mixes preferences and power plant characteristics (specific vintages, technologies, etc.) played an important, if not overwhelming, role. Besides, over the same period of time, let's keep in mind that 4.8 GW of carbon-free capacity and generation capacity featuring CCS was commissioned and 33.7 GW is planned by the five utilities.

[22] 1,483 $MtCO_2$ according to IEA data.

2.4.2 Financial investments and ETS compliance perimeter

After having looked at the whole picture and the impact of operating investments on potential emissions, we now look at the impact of changes in ownership on generation installations covered by the EU ETS. Even though financial investments were not entirely motivated by the European carbon constraint, investments that occurred changed the ETS compliance perimeters for the five major utilities under scrutiny.

We have isolated investments (investments as such, divestitures and swaps) in various generation technologies within EU ETS-constrained countries (EU27 and Norway) in our database to analyse the changes in attributable generation capacity (and therefore ETS compliance requirements). As explained earlier, changes in attributable generation capacity are defined as percentage change in ownership times the generation capacity. We acknowledge that a below 5% ownership in a carbon-emitting plant within the EU does not necessarily entail management of related carbon assets. Still, its profitability is affected. Based on the data we have collected, we have been able to distinguish between additions and removals to attributable generation for six main categories of power generation: coal-fired[23], oil-fired, gas-fired (conventional and CCGT), CHP (when a specific fuel feedstock could not be determined), renewables and nuclear. Figures 2.15 and 2.16 present the results for this analysis.

Coal-fired generation We find that 17.3 GW of existing coal-fired generation was added to the consolidation scope of the five most carbon constrained European utility groups. The main reason why is the impact of major deals in order to penetrate foreign markets where there is a significant amount of coal-fired generation already present. Another reason is that a large share of this additional coal-fired generation was acquired from Eastern Europe governments as part of the liberalisation process. The five groups most often plan major repowering and environmental expenditures on these plants.

In parallel to that, 8.9 GW of existing coal-fired generation was transferred out of the consolidation scope of the five utilities. On the one hand, some of these assets are actually transferred to other major utilities part of our sample (like EDF's stake in SNET transferred to E.ON in 2009) or beyond our sample (like EDF's stake in Hidrocantabrico via EnBW sold to EDP in 2004). In those cases, coal-fired generation is transferred to energy groups with the technical know-how and most often the will to improve the emissions profile of the power plants. On the other hand, we found that some

[23] Coal or lignite is used as the main feedstock even though the power plant may be co-fired using oil for instance.

coal-fired generation was transferred to non-energy groups (banks and hedge funds notably) without direct access to the technical know-how and a short-term view that would not necessarily foster retrofitting investments. One such case was EDF Energy's compulsory divestiture of Eggborough 2 GW coal-fired plant in the UK in order for the EC to approve of the British Energy's takeover. The plant was sold to a banking consortium representing the majority of the plant's bondholders (including distressed debt funds for about 80% of the debt claims) without indications of future plans for the plant[24].

Overall, the net balance indicates that 8.4 GW of coal-fired and assimilated generation was transferred in the hands of the five main carbon-constrained groups as part of their expansion plans. There was also some changes in coal-fired generation projects ending up with the five groups having ownership of some 700 MW of future coal-fired generation.

Oil-, gas-fired generation and CHP 4.9 GW of existing oil-fired generation, 12.0 GW of existing gas-fired generation (1.5 GW of CCGT generation planned) and 2.7 GW of existing CHP attributable capacity changed hands in favour of the five utilities. Over the same period of time, this represents more than the additional attributable coal-fired capacity. Interestingly, theses changes were not always a consequence of major deals and were, in part, direct investments in project companies for existing or future power plants.

Some 5.4 GW of attributable generation capacity based on oil, gas or CHP (including 3.7 GW for gas-only) were transferred out of the five top emitting utilities' consolidation scope. These were the result of large deals involving other energy groups except for disposal of relatively small generation to municipalities.

Overall an additional net 14.2 GW of relatively less carbon-emitting generation was transferred to the five utilities, which is nonetheless 5.8 GW more than net additional coal-fired generation.

Carbon-free generation 13.2 GW of existing and 9.4 GW of planned attributable renewables generation capacity were added to the scope of consolidation of the major five European utilities. Most of the existing capacity is hydroelectric and benefits clearly depend on remaining lifetimes for concessions in several countries. The bulk of planned capacity is made of wind (both onshore and offshore) generation projects acquired from wind project

[24]Bloomberg news (April 1st, 2010) available here: http://www.businessweek.com/news/2010-04-01/edf-transfers-u-k-eggborough-plant-to-bondholders-update1-.html

developers or regional utilities that had pursued external growth as well.

5.9 GW of existing renewable capacity was removed from the consolidation scope of the top emitting utilities. Still, renewable generation remained among major European utilities (Dong, Union Fenosa, EDP, etc.).

In the end, a net additional existing renewable capacity of 7.3 GW and potentially 8.8 GW more, pending further development (subject to ulterior PP&E investment and the maintaining of favourable incentive schemes), have been transferred to the most carbon constrained utilities.

Nuclear generation capacity of 14.6 GW (14.4 GW net of removals) was added to the consolidation scope of the top five emitting utilities. These were in great proportion acquired in the course of major acquisitions (Endesa and British Energy notably).

Finally, we aggregated data for carbon-emitting attributable generation and carbon-free generation (see Figure 2.17). We observe that the five most carbon-emitting utilities have approximately added as much carbon-emitting (22.6 GW) as carbon-free (21.7 GW) existing capacity to their assets via external growth. After all, financial acquisitions are part of potential answers from carbon-constrained entities as was claimed by RWE with the acquisition of Essent.

Taking into account additional potential generation, the picture changes and more carbon-free generation is added (30.5 GW vs. 24.4 GW). Still, as said earlier potential / planned generation requires additional investment, is risky and was propelled and sustained by direct incentive policies[25].

2.4.3 Specific EU ETS-related developments

Over the sample period, we observed several investments that might be indicative of positive or creative responses to the European carbon constraint on the part of regulated entities: carbon leakage, combination of operating / financial investment with Kyoto project mechanisms and cancellation or delays in power generation.

Carbon leakage in power generation

While in the literature, carbon leakage almost exclusively caters to industrial sectors, we find evidence of plans for carbon-emitting generation outside

[25] If we were to refine the analysis in order to better grasp the impact of tons of CO2 actually transferred over this period, we would at least need the (1) year the plant was commissioned, (2) its expected lifetime and (3) expected fuel mix over its lifetime.

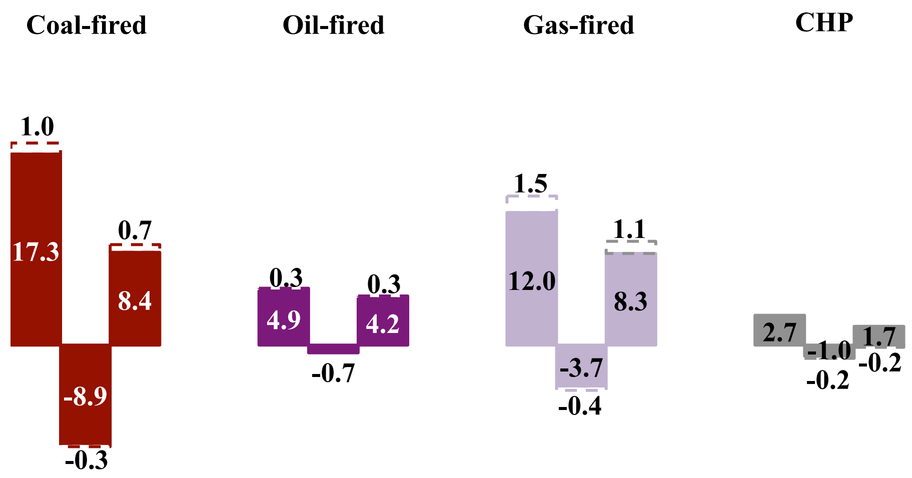

Figure 2.15: Changes in carbon-emitting attributable capacity over 2004-2009 in EU+EEA (additions, removals and net effect) - in GW

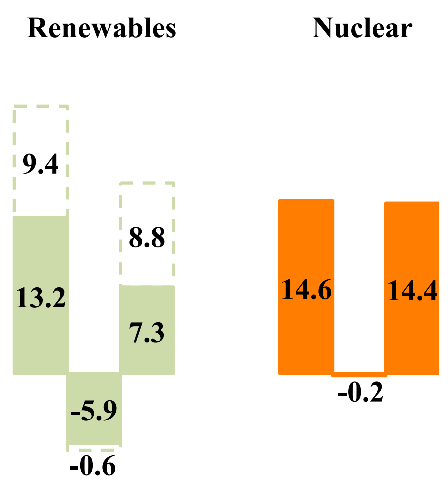

Figure 2.16: Changes in carbon-free attributable capacity over 2004-2009 in EU+EEA (additions, removals and net effect) - in GW

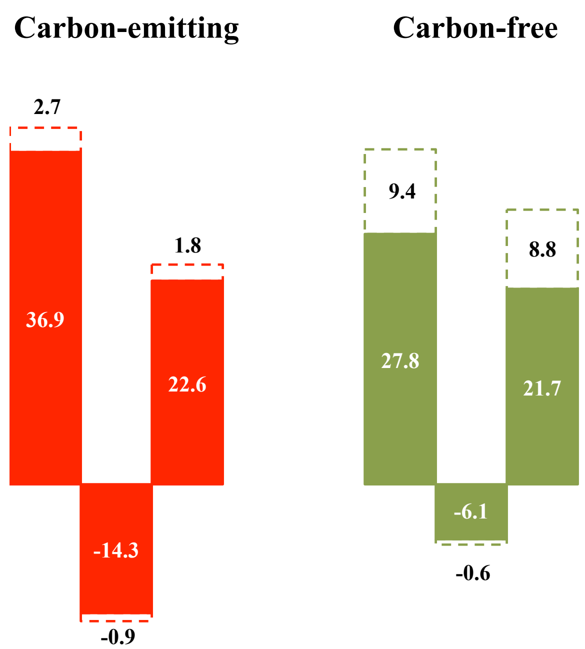

Figure 2.17: Changes in attributable capacity over 2004-2009 in EU+EEA (additions, removals and net effect) - in GW

the EU borders. In one case for instance, a special purpose entity was set up in 2009 for EUR 33 million to build 800 to 1,600 MW of coal-fired generation in Albania and overseas transmission cables to bring part of the power generated back to Italy[26]. While the EU ETS cannot explain alone this type of leakage, it surely plays a role. More generally, in EU member states sharing borders with non-EU countries, there is an incentive to do so if this behaviour is not flagged as an inappropriate way to cope with the EU ETS constraint by policymakers.

Kyoto project investment in affiliates

Among our sample of both operating and financial investments, we were able to identify various resorts to Kyoto project mechanisms. The objective was to boost investments' profitability of generation projects in subsidiaries or affiliated companies in eligible countries. We find that power generation entities whose European combustion installations fall within the scope of the EU ETS often had affiliated companies in Eastern Europe or South America for instance. The entities may resort up to a certain percentage to Kyoto

[26]It was although stated that the coal-fired plant would use the latest technology (without additional precision at the time of writing) and that the commissioning of additional capacity would address issues related to the power generation mix of Albania.

project mechanisms for their own compliance with the EU ETS. Rather than investing in *any* CDM or JI primary project based on a project-only cost-benefit basis, what some of the sample companies did was to invest by considering the whole impact on the profitability of the entity. In clear, investing in its own affiliates reinforces their overall emissions balance and profitability in addition to helping coping with the European carbon constraint. Hereafter, we provide two examples from our database involving resort to the joint implementation mechanism in the area of power generation. As regard financial acquisitions, the transfer of the Wolin-North wind farm from Dong to Vattenfall in the course of the major Elsam A/S asset swap also transferred the underlying JI project (Lake Ostrowo wind farm) implemented by its previous owner.

Regarding operating investments, an illustration of this trend is the construction of four CCGTs by E.ON in Russia via its stake in OGK-4 (76%), which qualified as JI projects. E.ON Carbon Sourcing, a 100% subsidiary of E.ON Climate and Renewables, acts as the other party in the mechanism that fund the investment cost and will use the ERUs generated. In particular, the JI projects[27] are:

- "Installation of CCGT-400 at Shaturskaya TPP" with a projected plant efficiency expected at nearly 56% and an emissions factor of 0.361 tCO2/MWh. Total investment cost is EUR 398 million. Compared to a combined margin emission factor (from existing power plants and new energy units) of 0.540 tCO2/MWh, the total estimated emission reductions over the period 2010-2020 amount to 5 millions ton of CO2e (1.1 MtCO2e over the 2009-2012 crediting period).

- "Installation of new CCGT-400 at Yaivinskaya TPP" with a projected plant efficiency expected at nearly 58% and an emissions factor of 0.370 tCO2/MWh. Total investment cost is EUR 419 million. Compared to a combined margin emission factor (from existing power plants and new energy units) of 0.601 tCO2/MWh, the total estimated emission reductions over the period 2011-2020 amount to 6.1 millions ton of CO2e (0.9 MtCO2e over the 2011-2012 crediting period).

- "Installation of two CCGT-400 at Surgutskaya TPP-2" with a projected plant efficiency expected at approximately 56% and an emissions factor of 0.364 tCO2/MWh. Total investment cost is more than EUR 780 million. Compared to a combined margin emission factor (from existing power plants and new energy units) of 0.601 tCO2/MWh, the total estimated emission reductions over the period 2011-2020 amount

[27] For more details (project design documents, etc.), please refer to projects 0195, 0215 and 0216 on http://ji.unfccc.int.

to 12.7 millions ton of CO2e (2.3 MtCO2e over the 2011-2012 crediting period).

Similar CCGT projects in Russia have been implemented by other European energy utilities like Enel and Fortum for instance. We find that, to some extent, Kyoto project mechanisms contributed to power generation expansion in the East.

Cancellations and delays in generation projects

Another area in which the EU ETS and the negotiations for national and European CCS subventions clearly played a role was in investment timing and even completion thereof.

In 2009 and 2010, several coal-fired and one carbon-free coal-fired generation projects planned by RWE in Germany, Poland and in the UK were postponed because of the planned introduction of auctioning schemes in the EU ETS from 2013. While it was initially suggested that the projects would be postponed until the power producer would be able to cover the increased generation cost with higher electricity prices, it seems that the projects have been indefinitely postponed. Additional factors such as the economic crisis, public resistance or lack of direct support to these projects are to be added to the picture. Projects whose construction had already begun would be maintained[28]. Similar events are to be accounted for in other major European utilities.

The negotiations to obtain CCS support funding have triggered construction plans for those having obtained support from national governments (UK and Germany notably) and the EC, and delays or cancellations for those unable to benefit from direct support. In the former case, Vattenfall's Jänschwalde 385 MW oxy-fuel project in Germany, E.ON Maasvlakte 250 MW post-combustion project in Germany or Endesa's Compostilla pilot plant in Spain have benefited from up to EUR 180 million support by the EC on a project basis. In the latter case, when RWE did not obtain the EC support for its CO2-free power plant in Germany, it decided to halt its investment plan in this particular plant[29].

Both in the case of coal-fired generation and CCS units, it should be highlighted that (1) ongoing development of large-scale carbon-emitting generation projects in the most recent years has been rather sensitive to expectations of a reinforced carbon constraint, (2) announcements regarding

[28] Ruhr Nachrichten, January 22nd, 2009, Financial Times Deutschland June 17th, 2010 and Point Carbon September 9th, 2010. Therefore, some of these elements are not featured in our database and related discussion.

[29] Süddeutsche Zeitung November 12th, 2009.

planned generation has a high strategic value for energy groups, which can and has been used to leverage direct support to specific technologies like CCS and that (3) non-financial factors such as public acceptance or legal framework for carbon storage have played a major role.

2.5 Conclusion

In the early years of the EU ETS, European utilities investments were considerably more influenced by non-climatic considerations, notably the strategic repositioning of the industry towards a regional utility business and regulations in the areas of NOx and SO2 emissions, energy markets liberalisation and unbundling. In the absence of a consensual counterfactual investment scenario over the period, we can only highlight that some investments performed and planned are clearly in favour of mitigating carbon emissions without attributing this to the ETS directly but rather to the flurry of direct support mechanisms to renewables or energy markets developments. Besides, the impact of changes in compliance perimeters and to whom are transferred "dirty" generation assets should not be neglected.

The beginning of a tighter constraint in phase II (2008-2012) and more precisely the realisation of a shift to a top-down cap-and-trade scheme based on auctioning of allowances triggered more investment-related responses on the part of regulated entities. Some of these responses go in the sense of the policymaker, highly carbon-emitting plants are cancelled in favour of plants emitting less or no carbon at all and regulated entities fully use project mechanisms to foster investments in lower carbon power plants. However, some of the responses are rather creative and require further monitoring. These need to be addressed by policymakers, in particular when there is a risk of carbon leakage or when commissioning of required generation capacity is unduly postponed.

In order to better assess the effectiveness of the incentive given and to prevent deviations, more transparency is required. Individual best practices like the Carbon Disclosure Project or excellent investors communication department disclosures cannot substitute a mandatory reporting system on power generation projects at the European scale. These results supports the revision of the EC regulation concerning the notification to the EC of investment projects into energy infrastructure (Council Regulation 736/96) in favour of complementary reporting on financial, technical and environmental data.

Chapter 3

Impact of the EU ETS on investment in new generation: a real options approach

One of the stated objective of the EU ETS is to give the incentive to invest in low-carbon or carbon-free power generation technologies. Still, so far, the uncertainty about future carbon prices and the existence of technology-dedicated incentives like subsidies for CCS and feed-in tariffs or green certificates, might indicate that the carbon price has hardly played that role. Carbon price uncertainty has been often invoked as one of the reasons why delay investments in power generation capacity in the EU. More specifically, the lack of long-term visibility and volatility of the European carbon price have been strongly criticized by European utilities. This chapter tackles the issue of carbon price uncertainty for European utilities and tries to evaluate the claims of the power sector and find reasons why utilities investment planners would delay their investments in generation capacity or would favour specific investment alternatives over others.

After having reviewed in the previous chapters, the decision-making framework for European utilities (economics and policy) and practice in the face of climate policies, we turn to a more theoretical approach to understand the impact of this framework on investment in new generation. The objective of this chapter is not to compare generation technologies as was already done in the literature but to develop scenarios for investment portfolios.

First, we review theoretical development in investment decision-making, including a focus on real options valuation and why it is a more thorough approach than the traditional deterministic discounted cash flow (DDCF) approach.

Second, we present the investment decision-making model used to test our hypothesis. The model is a real options model able to (1) consider the attractiveness of several investment opportunities (power plants) over a fixed time window, (2) account for several sources of uncertainty (including the price of carbon), (3) flexibility in the decision-making process (timing and technology choice) and (4) a budget constraint. The method developed should help utilities decision-makers integrate their views on carbon prices in an investment decision framework and ultimately, the method employed should help identify sensitivity points to guide policy-makers when designing amendments to the rules governing the EU ETS. The model is solved using the least-squares Monte Carlo approach (Longstaff and Schwartz, 2001 [2] and Gamba, 2003 [3]).

Third, we will discuss economic insights and policy implications based on scenarios derived from the model. In particular, we will evaluate the impact of amendments to the carbon price, ETS features and non-ETS features on investment decisions. Policy-wise, the model indicates that attempts to limit market price volatility and / or ensure a quick reversion to long-term equilibrium are of little help when compared to giving indications regarding significant cap level at various points in time (indicative of the deterministic trend). Any significant information about future commitments is definitively more critical to decision-making than current or past carbon price behaviour. Furthermore, the price of carbon only contributes little to shifting investment decisions towards carbon-neutral or lower carbon investments. Rather, the price of carbon is critical to short-term adjustments (fuel-switching / trading / operation planning). Finally, technology-dedicated incentives seems to better provide an incentive towards the investment in carbon-neutral or lower carbon power plants.

3.1 Investment decision-making models overview

This section depicts the trends in investment decision-making models (and investment criteria as well) from those inspired by typical cost-benefit analyses to more recent evolutions and approaches (Monte Carlo simulations, real options, etc.).

3.1.1 Deterministic discounted cash flows (DDCF) valuation

When deciding upon undertaking investments, decision-makers are faced with the task of conducting a sound assessment and valuation of any target investment. This task is typically performed in a three-step process.

Step 1 - estimation of the project cash flows

The first step entails estimating future net proceeds (accounting-based earnings, cash measure, value-based measurement, etc.) from the investment under scrutiny. The financial analyst community widely advocates for the use of cash-based measures for valuation purpose, as they tend to limit or prevent the effects of accounting-induced distortions.

Cash inflows include revenues from sales, positive effects from tax shields, revenues from incentives (feed-in tariffs, sale of green certificates), etc. Cash outflows include capital expenditures and operation and maintenance expenses comprised of both variables costs like workforce salary, raw material costs, tax expenses and fixed costs like amortization, borrowing expenses, etc. Two critical components are (1) the initial investment cost incurred most often at the inception or over the first years and (2) the salvage value (also known as the residual or terminal value) received at the end of the project lifetime. While both are usually larger than interim cash flows, the latter is most often a fraction of the former (thereby accounting for amortization and changes in market value of the project). The data used is typically after-tax. By summing up initial investment costs, inflows, outflows and terminal value, we obtain net cash flows. Table 3.1 gives us such an example. An initial investment of EUR 1,000 provides here a recurring EUR 120 net cash flow over a 10-year period and an extra EUR 300 in year 10 for the investment terminal value.

Table 3.1: Net cash flows sample calculation

	t=0	t=1	t=2	...	t=10
Initial investment cost	- 1,000	-	-	...	-
Quantity sold	-	x 10	x 10	...	x 10
Sale price	-	+ 22	+ 22	...	+ 22
Inflows	-	+ 220	+ 220	...	+ 220
Outflows	-	- 100	- 100	...	- 100
Terminal value	-	-	-	...	+ 300
Net cash flows	- 1,000	+ 120	+ 120	...	+ 420

Step 2 - determination of an appropriate discount rate

Recognizing that a Euro today is worth more that a Euro tomorrow, we need to find a way of taking into account intertemporal effects. There is no directly comparing today's Euro and tomorrow's Euro. We cannot simply add or more fundamentally relate net cash flows from different periods of time without making them compatible first. Lending a Euro over a day should compensate its lender for foregoing his or her ability to spend it today.

Therefore, the second step entails accounting for the time value of money. Discounting future net proceeds using a proper discount rate to the moment of valuation performs this. The passing of time is accounted for using a risk-free rate as a discount rate (typically a short-term governmental money market security).

Step 3 - calculations of discounted cash flows and net present values

The third step relates all the discounted cash flows with the investment cost incurred by a given investment opportunity. Therefore, the so-called net present value (NPV) of an investment is the sum of discounted cash flows (labelled CF_t for the cash flow in period t discounted at the rate r) over the lifetime of the investment (from time 0 to T) minus the initial investment cost (a negative CF_0).

$$
\begin{aligned}
NPV &= \Sigma_{t=0}^{T} \frac{CF_t}{(1+r)^t} \\
&= CF_0 + \Sigma_{t=1}^{T} \frac{CF_t}{(1+r)^t}
\end{aligned}
$$

A positive NPV indicates that the project under scrutiny is creating value. The NPV rule suggests pursuing any investment whose NPV is positive. In case of multiple investment opportunities, the NPV rule guides investments towards projects with the highest NPV. The NPV rule is pretty straightforward and widely used among business practitioners.

For instance, assuming a 5% discount rate and using the same sample cash flow projection as in table 3.1, we end up with a positive NPV (EUR 111) - so the investment considered should be undertaken (see table 3.2). Another

Table 3.2: Net present value calculation

	t=0	t=1	t=2	...	t=10
Net cash flows	- 1,000	+ 120	+ 120	...	+ 420
Discounted cash flows	- 1,000	+ 114	+ 109	...	+ 258
NPV	+ 111				

important property that will be of use for our model later in this chapter is the additivity of NPVs:

$$
NPV(A+B) = NPV(A) + NPV(B)
$$

Limitations of the DDCF

In spite of being pretty straightforward and widely used by investment practitioners, the DDCF and NPV rule based on it have nonetheless shortcomings.

(1) Lack of flexibility First, DDCF (or discounted cash flows under certainty) do not particularly account for flexibility in the decision-making process or in the operation of the investments undertaken. The traditional

DDCF approach entails accepting all the outcomes of the projects once decided upon, it is a now-or-never decision and it systematically underestimates the asset value whenever real options are embedded (read flexibility in the process) (He, 2007 [49]).

Following Wang and de Neufville (2004 [50]) typology, we retain two main categories of flexibility that lack being accounted for in a DDCF framework. On the one hand, flexibility *in* projects, which is analogous to operating flexibility. This category includes the ability to change the operating mode of a plant, perform changes in the output quantity or quality, etc. This category features options which are created by changing the actual design of the technical system. On the other hand, flexibility *on* projects improves the NPV profile by including strategic flexibility: investment timing, expansion, contraction, etc. Real options *on* projects are similar to financial options taken on facilities or business units (merely treating technology as a black box).

Flexibility is accounted for by resorting to the real options approach or only some of its building blocks (decision trees, dynamic programming, other optimization methods, etc.).

(2) Uncertainty not accounted for Second, the assumption of certainty contrasts with an uncertain decision-making environment. In a certain decision-making environment, perfect foresight of each variable factored in the decision process is assumed.

Uncertainty can either be embedded in the cash flows (using scenarios, simulations, etc.) or in the discount rate or rates, adjusting it or them for risk. More technically, other related limitations includes the difficulty to estimate future cash flows because of their stochastic nature, the risk of making errors in choosing an appropriate discount rate, etc.

In the next pages, we review some of the improvements to the DDCF approach aiming at overcoming the limitations of the approach.

Improvements to the DDCF

Improvements to the DDCF have been added over the years. Some addresses specific issues and limitations (accounting for uncertainty, flexibility and investment constraints) while others provide a different set of profitability metrics and analyses (sensitivity analysis and simulation). We discuss these hereafter.

(1) Adjust the discount rate for risk In addition to the time value of money, an Euro tomorrow is somehow more uncertain in comparison to the certainty of holding a Euro today. In other words, it bears a risk that needs to be accounted for.

Typically, adding a risk premium to the risk-free rate - thereby discounting cash flows even more, allows to embed risk. This type of method of accounting for risk involves no modification to the cash flows at the numerator. Traditional corporate finance features such methods to account for the investment financing structure (weighted average cost of capital or WACC), return expectations in relation to some stylized models (capital asset pricing model or CAPM, etc.), etc.

(2) Scenarios An alternative to adjusting the discount rate for risk is to solely account for the time value of money in the denominator (i.e. use solely the risk-free rate without any risk premium added) and account for uncertainty in the numerator only. This is highly important in case different cash flow components bear different level of uncertainty (a secured government grant in comparison to a volatile market price for instance) and it would be unfair to discount them with a one-size-fits-all discount rate.

One approach is to consider that several stylized scenarios for future cash flow patterns are rather likely to happen than a single perfectly foreseen future. A probability of occurrence is attached to each of these scenarios. Working with expectations, decision-makers end up with expected NPVs to decide upon investments.

For instance, again, we assume a 5% discount rate and use the same sample cash flow projections. We attach a 0.5 probability to the base case scenario and a 0.25 probability to each of the two alternative scenarios, labelled high and low. Data is compiled in Table 3.3.

Table 3.3: Expected NPV calculation

	t=0	t=1	t=2	...	t=10
High case scenario (25%)	- 1,000	+ 220	+ 220	...	+ 520
Base case scenario (50%)	- 1,000	+ 120	+ 120	...	+ 420
Low case scenario (25%)	- 1,000	+ 70	+ 70	...	+ 370
Expected net cash flows	- 1,000	+ 133	+ 133	...	+ 433
Expected discounted cash flows	- 1,000	+ 127	+ 121	...	+ 266
Expected NPV	+ 211				

We find out an expected NPV of EUR 211 - again the investment considered should be undertaken. Please note that should the high case scenario materialize, we would have an even higher NPV (EUR 883) while should the low case scenario materialize, the project actually destroys value and the investor obtains a negative NPV (- EUR 275). Table 3.4 outlines benefits and

Table 3.4: Pros and cons of scenarios

Benefits	Limitations
- Accounts for uncertainty in an artificial manner.	- Major changes in the decision-making framework may jeopardize the resort to only a few scenarios; - Attaching probability to scenarios can be subjective and biased when performed by the investors.

limitations of using the cash flow scenario approach (based on Trigeorgis, 1996 [51] and Neuhoff, 2007 [52]).

(3) Sensitivity analysis Recognizing that any valuation performed hinges on the key variables behind cash flow projections and discount rates, investors often assess the impact of a change in key variables on the NPV holding other variables constant.

Starting with a base case scenario, the investor performs an initial NPV calculation. Then holding all the other variables constant, each variable of interest is changed by a certain range around its base case specification. The resulting range of calculated NPVs indicates the sensitivity of the investment profitability in case a key variable is not properly estimated (or should its value change over time).

Pursuing with our illustrative example, we perform two sensitivity analyses detailed in Table 3.5. It appears that below a sale price of EUR 20.56, the NPV of the investment under scrutiny becomes negative, i.e. the investment should not be undertaken. Likewise, should the assumption of selling 10 units turns out to be too optimistic, the investment becomes unprofitable (break-even point at 9.35 units sold).

We clearly see the benefits of this approach in terms of risk control and understanding of investment value drivers. Table 3.6 compares benefits and

Table 3.5: Sensitivity analysis sample calculation: sale price (P) and quantity sold (Q)

	P=20	P=21	P=22	P=23	P=24
NPV	- 44	+ 34	+ 111	+ 188	+ 265
	Q=8	Q=9	Q=10	Q=11	Q=12
NPV	- 229	- 59	+ 111	+ 281	+ 451

limitations of using the sensitivity analysis (based on Trigeorgis, 1996 [51]).

Table 3.6: Pros and cons of sensitivity analysis

Benefits	Limitations
- allows identifying and quantifying critical variables to investment decisions;	- takes only one variable at a time and ignores the impact of a combination thereof;
- whenever a variable is deemed highly critical, this could indicate that it is worth investing additional resources (time and / or money) to reduce the corresponding uncertainty;	- estimates of a variable could be serially dependent over time, therefore a forecast error for a given year might propagate even more in subsequent years;
- indicates variable-specific thresholds above or below which an investment becomes unprofitable.	- ignores interdependencies among variables.

(4) Simulations Simulations involves resorting to a mathematical model depicting the investment framework and specific conditions featuring randomness. The typical methodology used is that of the Monte Carlo simulation which involve a four-step process. First, the investment under scrutiny

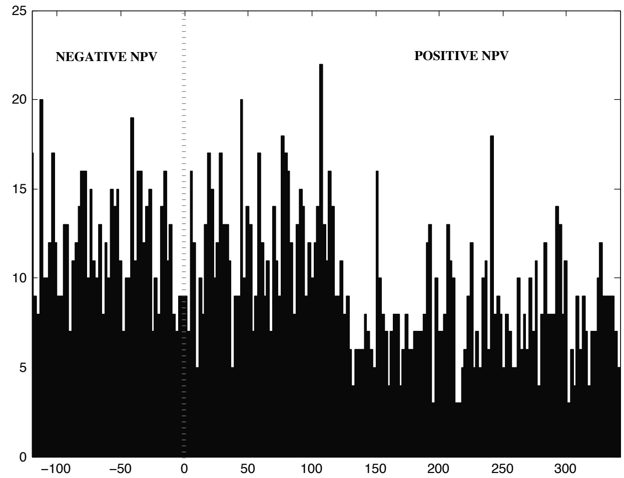

Figure 3.1: Monte Carlo NPV simulation with a stochastic sale price (frequency of various levels of NPV)

and all the key variables and relations among them and over time are modelled mathematically. Second, a probability distribution is attached to each of the key variables. This is typically performed using past empirical data or subjective data (i.e. expert guidance or results from third-party models). Third, a large number of random values are drawn for the key variables (usually generated using a computer) and are used to calculate the NPV. Fourth, based on the large number of NPVs calculated, we approximate a probability distribution for the NPV.

Figure 3.1 shows a sample NPV distribution based on a stochastic sale price simulation. We observe that the simulation indicates that the NPV can be somehow remote from the DDCF method (EUR 111). The NPV ranges from minus EUR 120 to a positive NPV of EUR 350 with a significant number of simulated NPVs below zero.

Table 3.7 compares benefits and limitations of using simulations (based on Trigeorgis, 1996 [51]).

Table 3.7: Pros and cons of simulations

Benefits	Limitations
- Allows handling complex investment problems;	- Some interdependencies among key variables are quite difficult to correctly model or entail resorting to third-party modelling which comes at pecuniary and agency costs;
- Overcomes limitations of sensitivity analysis.	- There is possibly a double-counting issue regarding risk - risk is inherent in the NPV distribution concept and most often already accounted for in the risk-adjusted discount rate;
	- Difficulty to motivate a decision based on the insights from a NPV distribution (expected NPV and variance) - no clear-cut decision based on a criteria;
	- Unreliability of extreme values (distribution tails);
	- Cannot handle quite well investor flexibility but rather stick to a business-as-usual operating mode.

(5) Incorporating capital rationing When undertaking investment valuations, limited resources at the corporate level should be acknowledged (Brealey and Myers, 2003 [53]). Capital rationing means that an investor cannot undertake all the positive-NPV investments because of a likely budget constraint.

We distinguish between soft and hard capital rationing. Soft capital rationing corresponds to management provisional limits to guide the investment decision-making process while hard capital rationing means that no new money can be raised to invest in a positive-NPV project even though a few Euro might be missing. Hard capital rationing implies market imperfections that may render the NPV rule invalid. Clearly in the case of the European power sector, money can be raised by dint of various term loans, lending facilities and ability to issue stock for instance. We acknowledge being in a soft capital rationing environment.

Two types of methods have been developed in the literature and among practitioners to incorporate the budget constraint into decision-making.

First, a ranking of positive-NPV investments based on a profitability criteria helps determine the most profitable combination of investments. This is what the profitability index, defined hereafter, does.

$$\text{Profitability index} \quad = \quad \frac{\text{NPV}}{\text{Initial investment outlay}}$$

Nevertheless, this ranking method does not allow for more complex corporate capital rationing schemes with more than a pure budgetary constraint (new investments available over time, etc.).

Second, a more general approach to incorporating capital rationing suggest resorting to linear programming or integer programming (i.e. do not allow for investment in fractions of projects). The optimization consists in finding the weights (i.e. the quantities) attached to investment projects so that the combined NPV is maximized under a set of various constraints (respect budget constraint at various points in time, no negative weights, no fractional investment, etc.). The optimization procedure is solved using computer software.

(6) Decision tree analysis Decision tree analysis helps the investor map out all forms of flexibility (actions) contingent on the possible states of nature (external events) in a hierarchical manner (Trigeorgis, 1996 [51]). The investor chooses the combination of choices that is consistent with the maximization of expected NPV.

Figure 3.2 depicts a typical decision tree approach. Decision points for the investor are identified by a box and elements beyond his or her control by a circle (no influence on R&D outcomes or on the market acceptance for the end-user product). In this illustrative example, the investor faces the choice in time 0 to invest or not in a R&D project. If he or she chooses to do so, he would incur a EUR 0.1 million cost with only a 30% chance of success. He may also simply walk away before engaging in the R&D project. In case the R&D project fails (70%), the investor loses the initial investment. In case it succeeds (30%), the investor has the possibility (second box) to build a plant to manufacture the final product, which means another EUR 3 million cash outlay. Then, the investor would be waiting for the market response which is modelled using three scenarios (low, mid and high). In case market response is low, the investor has the flexibility to abandon the plant (i.e. sell it) for its salvage value, recovering a percentage over the plant investment cost and preventing any further addition losses.

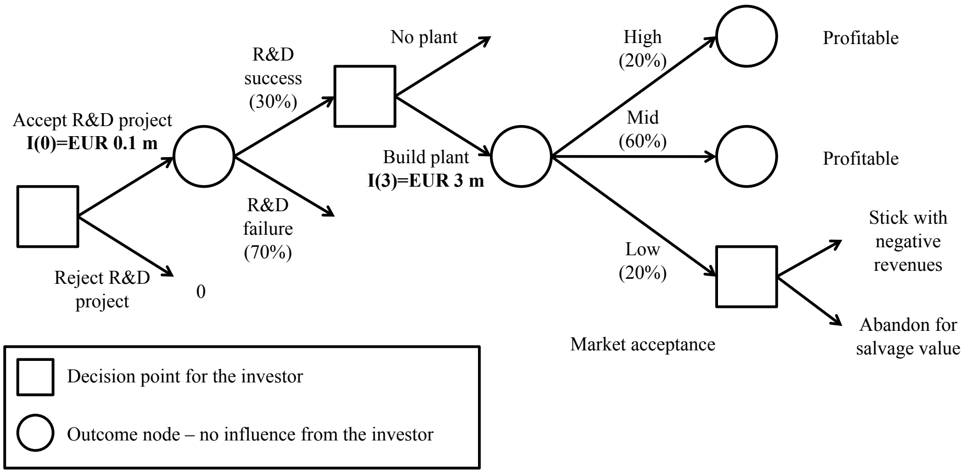

Figure 3.2: Sample decision tree (adapted from Trigeorgis, 1996)

Compared to DDCF, this approach accounts for flexibility in the management of the project with three exit points for the investor: at the R&D stage (no participation at all indeed), at the industrialization phase and according to the market response. These exit points are included in the valuation of the investment and typically add value to the project under scrutiny given that flexibility here benefits the investor able to cut losses. Directly comparing the value of the project with flexibility with its uncertain discounted cash flows counterpart (solely scenarios for instance) allows the investor to identify and quantify the value of flexibility (option value following the real options terminology).

The way decision tree problems are solved often entails working with expectations from the rightmost tree developments to the initial value of the project using recursive methods (dynamic programming, average-out-and-fold-back or roll-back procedures).

Table 3.8 compares benefits and limitations of using the decision tree analysis (based on Trigeorgis, 1996 [51]).

3.1.2 Other investment criteria used by practitioners

In the traditional DDCF decision-making and all its improvements suggested in section 3.1.1, the choice upon an investment relied on the NPV criteria.

Table 3.8: Pros and cons of decision tree analysis

Benefits	Limitations
- Appropriate and helpful for analysing sequential investment decisions when uncertainty is resolved at discrete points in time;	- In real life, investors may not have to be committed to the entire string of events related to an investment;
- Influence management to consider consequences from short-term decisions;	- Can become unmanageable or untractable in case too many paths are considered;
- Provide guidance to the decision-maker based on expectations and distributions on key variables.	- The use of an identical discount rate over each paths can be problematic.

Still, instead of resorting to the NPV rule, many investors rely on other investment criteria to decide upon investments. While these alternative criteria can be somewhat widely used in practice, they are inferior to the NPV criteria for many reasons (to a lesser extent for the internal rate of return). Using other investment criteria also has to do with the perspective or focus of the decision maker. A utility's corporate finance department would typically focus on NPV, institutional investors providing equity to infrastructure investments would focus on the internal rate of return and how a new investment would fit an existing investment portfolio, etc.

Alternative criteria 1 - internal rate of return One the most common alternative investment-decision metric used is the internal rate of return (IRR). It corresponds to the discount rate that would make an investor indifferent between receiving the initial investment cost or the string of subsequent discounted cash flows (in other words, the discount rate so that the NPV is zero). Mathematically, the IRR is found by running an iterative (trial-and-error) procedure solving:

$$-CF_0 = \Sigma_{t=1}^{T} \frac{CF_t}{(1+IRR)^t}$$

The IRR represents a rate of return for an investor. The investment rule associated with the IRR is somehow similar to that of the NPV. While with the NPV, the criteria had to be positive to motivate an investment, with the IRR, the alternative criteria has to be higher than the investor's own required rate of return.

Recalling our initial example, the IRR is the discount rate that solves the following equation:

$$\underbrace{1,000}_{\text{initial investment}} = \underbrace{\Sigma_{t=1}^{10} \frac{120}{(1+IRR)^t}}_{\text{annual net CF}} + \underbrace{\frac{300}{(1+IRR)^{10}}}_{\text{terminal value}}$$

Using a spreadsheet software, we find that the IRR is equal to 6.91%, which is in excess of the assumed 5% discount rate. So the investment should be undertaken as it generates more profits than the reference discount rate (risk-free rate or investor's cost of capital).

Still, the IRR has shortcomings. In particular, it becomes problematic to estimate the IRR using an iterative procedure when more than one outflow is required. For instance, assume that instead of incurring EUR 1,000 now, we engaged in multiple significant outflows over the life of the investment (changing a unit ten years from now) - we might find that several IRR exists (an issue known as the multiple IRR problem). This would render the evaluation using the sole IRR criteria impossible.

Alternative criteria 2 - payback rule The payback period for an investment is the number of years it takes before the cumulative forecast cash flows equals the initial investment outlay (Brealey and Myers, 2003 [53]). In our initial example, the payback period would be 9 years. A typical payback

Table 3.9: Payback calculation

	t=0	t=1	t=2	...	t=10
Net cash flows	- 1,000	+ 120	+ 120	...	+ 420
Cumulative cash flows	- 1,000	- 880	- 760	...	+ 500

rule would be invest solely in projects which have a payback cut-off period below 2 or 3 years for instance.

Nevertheless, this method has two main shortcomings. On the one hand, the payback rule ignores cash flows beyond the cut-off date be it an additional major outflow or a windfall profit that would not be considered given the short-term bias taken (i.e. rejection of long-term strategic projects). On the other hand, an equal weight is given to all the cash flows which favour investments with earlier profits.

An alternative is to resort to a discounted payback calculation. Implicitly, this gives more weight to cash flows in the earlier years compared to those in the later years (thereby overcoming the second shortcoming). Using our example, we find a payback period of 10 years.

Table 3.10: Discounted payback calculation

	t=0	t=1	t=2	...	t=10
Discounted cash flows	- 1,000	+ 114	+ 109	...	+ 258
Cumulative DDCF	- 1,000	- 885	- 777	...	+111

Alternative criteria 3 - book rate of return Most investors report book-related data and therefore compute book rate of return on investments under scrutiny. The book rate of return is defined as such:

$$\text{Book rate of return} = \frac{\text{book income}}{\text{book assets}}$$

Relying on accounting data to value investments is dangerous as valuation hinges on accounting treatment and acceptable options available (capitalize or treat a cost as an expense, depreciation rate schedules, revenue recognition timing, etc.) which can be subject to manipulation by management and amendments to accounting rules.

3.1.3 Real options valuation

In response to the limitations of the traditional discounted cash flow approach and building upon several improvements to the valuation process that have been discussed in the previous sections (scenarios, simulations, etc.), the real options approach aims at capturing more reality in the valuation process.

Development of the real options theory

The real options approach (ROA) essentially builds on the financial options theory (see the box afterwards for a review of the terminology based on Hull (2003, [54]) - and most predominantly the seminal works on option pricing by Black and Scholes and Merton, the binomial approach by Cox, Ross and Rubinstein as well as on stochastic price modelling[1].

Financial options concepts

Call option: an option to buy an asset at a certain price (strike or exercise price) by a certain date. While the buyer of a call option can exercise the option or not, the seller (or writer) of the call option has the obligation to sell the asset at the agreed-upon price and date should the buyer decides so.

[1] For a recent treatment on this topic, refer to Shreve (2004) [55] and Shreve (2006) [56].

Put option: an option to sell an asset at a certain price (strike or exercise price) by a certain date. While the buyer of a put option can exercise the option or not, the seller (or writer) of the put option has the obligation to buy the asset at the agreed-upon price and date should the buyer decides so.

Types of options: a European option can be exercised only at the end of its life. An American option can be exercised at any time during its life and a Bermudan option can be exercised on specified dates during its life.

Factors affecting option prices: The following elements have been identified as having an impact on the price of an option: (1) the price of the underlying asset (both current and strike price), (2) the time to expiration (or maturity) of the option, (3) the volatility of the underlying asset price, (4) the risk-free interest rate and (5) interim cash flows or dividends expected during the life of the option.

Risk-neutral valuation is also a major building block of the ROA with the contingent claim analysis (replicating portfolio and use of spanning assets) and the certainty-equivalent approach. Finally, the most recent works (especially in the face of ever more complex problems) involve numerical methods to avoid solving analytically real options problems. In this respect, the landmark works on dynamic programming (Bellman, 1957 [57]) have been supplemented with backward-looking Monte Carlo simulations (Longstaff and Schawartz, 2001 [2]) and control-variate methods with numerical approximations. Reference works on the ROA include textbooks by Dixit and Pindyck (1994) [1] and Trigeorgis (1996) [51] and papers by Brennan and Schwartz (1985) [58] on multiple option framework for a mine's optimal management and Pindyck (1988) [59] on the options to choose capacity under product price uncertainty.

On the practitioner side, it should nonetheless be acknowledged that the ROA is by no means a one-size-fits-all method. The method is nonetheless fraught with conceptual and implementation difficulties and has more often gained acceptance among academics rather than by decision-makers (1) for fear of resorting to a "black box" (He, 2007 [49]), (2) because of activity-based compensation systems encouraging management to exercise options too early (Sick and Gamba, 2005 [60]), etc. In a survey of management capital budget practice, Block (2007, [61] finds that out of 279 professional respondents, only 14.3% currently used real options. Among the reasons for not using real options were: (1) lack of management support (42.7%),

(2) DDCF is a proven method (25.6%), (3) requires too much sophistication (19.5%) and (4) encourages too much risk taking (12.2%). Nonetheless, recent papers employing new approaches (notably the least-square Monte Carlo approach detailed afterwards) show how it is possible to solve complex options using computer-based simulation procedures. This should help promote the use of ROA among practitioners.

Improvements in relation to the DDCF

In an effort to overcome the limitations of the net present value (NPV) rule under deterministic discounted cash flows (DDCF), the real options methodology suggests an approach that can be used to *complete rather than replace* the traditional NPV rule. In particular, the real options approach (ROA) features a combination of the following four improvements.

(1) Investment timing First, the real options approach (ROA) allows the decision maker to postpone the initial investment undertaken - this gives the investor flexibility in the investment timing (option to defer) instead of the traditional now-or-never investment decision. The investor may consider that an investment, if undertaken now, will not be profitable based on uncertain cash flow projections. Suppose, that a great deal of the uncertainty is resolved one year from now - surely, that would make sense to account for this ability to postpone the investment one year from now. The ROA permits to capture this effect.

A simple example should clarify the impact on valuation (the illustrative example is largely inspired from Dixit and Pindyck, 1994 [1]). Consider an investor pondering whether or not to invest EUR 1,000 now in a project that is expected to last forever (a perpetuity in actuarial jargon). It is only one year from now that the investor will know the value of the perpetual annual cash flow. As of today, the investor expects that the cash flow will be EUR 40 with a probability of 0.5 and EUR 60 with a probability of 0.5 as well. Expected cash flow is therefore EUR 50. The discount rate employed here is set at 5%.

$$
\begin{aligned}
E(NPV) &= -1,000 + \Sigma_{t=0}^{\inf} \frac{(0.5).40 + (0.5).60}{(1.05)^t} \\
&= -1,000 + \frac{(0.5).(40) + (0.5).(60)}{0.05} \\
&= -1,000 + 1,000 \\
&= 0
\end{aligned}
$$

We obtain an expected NPV (E(NPV)) equal to zero indicating no peculiar set of action - the investor might be better off pursuing alternative investments with positive NPVs. Still, the previous calculations ignore the opportunity cost of investing now rather than waiting and keeping open the ability not to invest should prices go.

Now, recognizing that in reality, investment opportunities are seldom on a now-or-never basis and that investor have the ability to postpone investments to acquire a better information, we move to the case where uncertainty is resolved in time 1. If the market price turns out to be a EUR 60 cash flow, the investor would invest and if the price turns out to be EUR 40, he would simply not invest. Making things comparable with the previous case (i.e. discounting back to t=0), we obtain:

$$\begin{aligned} E(NPV) &= (0.5)[\frac{-1,000}{1.05} + \Sigma_{t=1}^{\inf} \frac{60}{(1.05)^t}] + (0.5).0 \\ &= 66.67 \end{aligned}$$

Consequently, if we wait one year to decide upon investing the project's NPV today is EUR 66.67 in comparison to EUR 0 if the investor was to invest only now. The project remains the same, only the valuation differs.

The improvements in terms of investment timing can easily be adapted to account for all types of options *on* projects. Following the typology by Trigeorgis (1996, [51]), we consider:

- **Option to defer or accelerate investment**: for instance, when a licence to operate an industrial site allows the investor to defer the investment in the future and benefit from the resolution of uncertainty regarding climate negotiations;

- **Option to default/stop between completion / construction stages**: for instance, consider a US utility pursuing multiple permitting applications. The utility announces the constructions of multiple and relatively similar power plants on the US soil. The utility progresses at the scheduled pace in the investment outlay process but consider and value its ability to halt the process should regulatory or any other risk jeopardize the profitability of the investment beyond incurred and default costs (see Walls et al., 2007 [62]);

- **Option to alter investment scale (expand or contract)**: in the case of an expansion, we suggest valuing the investor's ability to incur a follow-up cost to scale up the production (increase power plant capacity) later on should appropriate market conditions be met (lower carbon price for instance). Sticking to the financial options analogy, the investor actually is the owner of a call option he may exercise should the price of the underlying (actual future market conditions) go higher than the strike price (initial expectations regarding future market conditions). Following a similar analogy, an option to contract would be analogous to a put option, in which the strike price would equal potential cost savings (from reduced costs from higher carbon prices for instance);

- **Option to abandon an investment for its terminal value**: quite similar to the option to contract, the investor has the option to abandon the power plant investment permanently in exchange for its terminal value. The option is similar to an American put option on the power plant's current value with a strike price equal to the terminal value;

- **Corporate growth options**: these options set the path of future opportunities and are of primary strategic importance. Suppose a European utility is building a pilot coal-fired plant to test a carbon capture and storage technology. Although in isolation, the venture could appear unprofitable, it might turn out to be the first in a series of similar plants if the technology is successfully developed and implemented at an industrial scale. Value rather comes from unlocked future growth opportunities (Trigeorgis, 1996 [51]).

(2) Operating flexibility Second, the ROA permits the decision maker to value the operating flexibility in the underlying asset. For instance, Figure 3.3 (adapted from Geman, 2006 [63]) illustrates how a flexible CCGT plant (not bound by long-term supply contracts) can be profitable. Basically, the power plant operates when market conditions are profitable and is shut down when it becomes unprofitable. The investor is trying to identify what

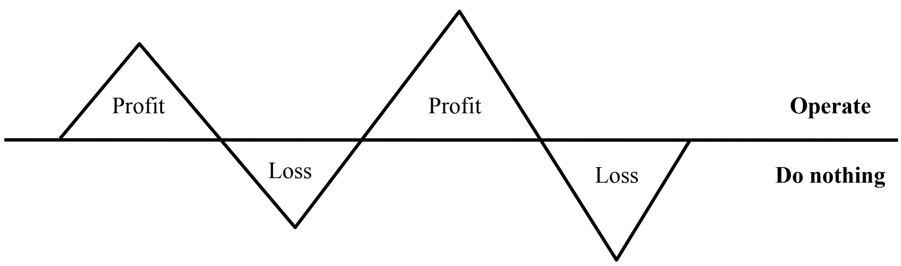

Figure 3.3: Valuation of a flexible CCGT

internal flexibilities can be reasonably incorporated in the valuation process to improve the NPV profile (and the quality of the valuation by the way).

The likely impact on the NPV profile is illustrated in Figure 3.4 (adapted from Frayer and Uludere, 2001 [64]). With flexibility, the upside can be captured without the downside risk (or at least not all of it). In particular,

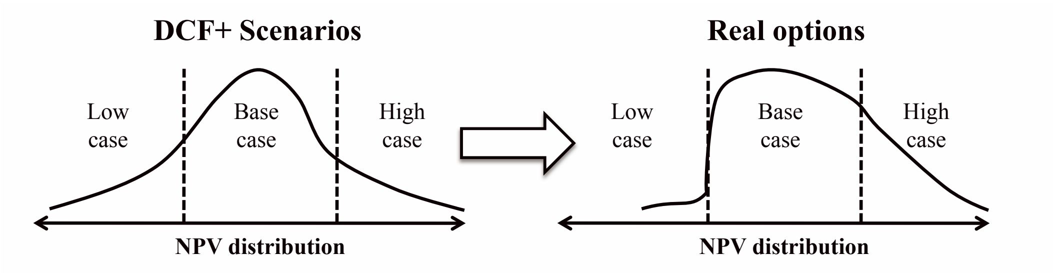

Figure 3.4: NPV profile: DDCF vs. ROA

Trigeorgis (1996, [51]) identified the following operating real options:

- **Option to stop and restart operations**: Obviously, in some cases the line is thin between options *in* and options *on* projects. We argue that the ability to temporarily switch off a plant (a process called mothballing) should the market environment become unprofitable rather belongs to operating flexibility because of the possibly temporary character of the operation.

- **Option to switch use for inputs and outputs**: For instance, consider a power plant in the UK either able to switch fuel from coal to natural gas when market prices make it more profitable or able to co-fire a variable quantity of biomass to generate power. On the output side, process flexibility could be illustrated for instance by the ability of a CHP plant in Germany to produce variable quantities of power and heat for a given energy input depending on market prices, long-term contracts and incentives. Process flexibility is achieved with technology capability, access to alternative input and output and switching among processes as their relative costs and prices change.

(3) Accounting for uncertainty Third, the ROA typically incorporates some way of accounting for uncertainty. This can be performed by resorting to discrete or continuous-time (diffusion) models of risk. The former entails resorting to binomial tree modelling for instance.

In the latter case, the mathematical depiction typically takes the form of a general stochastic differential equation (SDE) used to model processes under uncertainty, typically equity or commodity prices. Following Dixit and Pindyck (1994, [1]), a stochastic process is a variable that evolves over time in a manner that is at least random. It is defined by a probability law for the evolution X_t of a variable X over time t. A typical SDE has the following form:

$$dX_t = \underbrace{F(X_t)dt}_{\text{drift component}} + \underbrace{G(X_t)dW_t}_{\text{diffusion component}}$$

where:

- X_t = the process variable to simulate (in our case, the price of carbon allowances, p^c_t or its natural logarithm, $ln(p^c_t)$);
- dX_t = the change in the process aforementioned;
- $F(X_t)$ = the drift rate function which is the trend component of the SDE. Two typical drift rate functions are commonly used for economic and financial time series:
  - A "linear drift rate" taking the following shape:

    $$F(X_t) = A_t + B_t.X_t$$

    where A_t is the intercept term of $F(X_t)$ and B_t is the first-order term of $F(X_t)$ (slope or linear growth component).
  - A "mean-reverting drift rate" specification taking the following shape:

    $$F(X_t) = \theta_t.(X^*_t - X_t)$$

    where θ_t is the mean reversion speed, i.e. the time it takes for the price process to go back to its long-term (also named "normal") average level, X^*_t, to which the process eventually reverts to ($\theta_t \geq 0$).
- $G(X_t)$ = the diffusion rate function expressing the behaviour of the process around its trend (variability);
- W_t = a Brownian motion vector, which increments are used to model shocks to the processes. A Brownian motion (also known as a Wiener process) is a continuous-time stochastic process with three important properties: (1) it is a Markov process (probability distribution for all future values of the process depends only on its current value), (2) it has independent increments (the probability distribution for the change on the process over any time interval is independent of any

other time interval) and (3) changes in the process over any finite interval of time are normally distributed. Note that W_t could instead be a Poisson jump process or a variety of processes. It is all about making an assumption for the distributional characteristics of the source of uncertainty.

When modelling energy prices (especially power and natural gas), two major approaches have been used.

First, single factor models are the simplest type of reduced-form models. They basically feature the drift and diffusion components aforementioned. Commonly-used stochastic processes include:

- the Geometric Brownian Motion (GBM) or lognormal diffusion process in which the drift $F(X_t) = \alpha.X_t$ and the diffusion $G(X_t) = \sigma.X_t$. GBM are frequently used to model stock prices, interest rates, wage rates, output prices and other economic and financial variables.

- the Arithmetic Brownian Motion or normal diffusion process in which the drift $F(X_t) = \alpha$ and the diffusion $G(X_t) = \sigma$;

- The Ornstein-Uhlenbeck mean reverting process in which the drift $F(X_t) = \theta.(X_t^* - X_t)$ (mean-reverting drift rate) and the diffusion $G(X_t) = \sigma$. The process is typically used for the prices of raw commodities that should be related to the long-run marginal production cost. There are nonetheless short-run fluctuations but the process reverts back to to the marginal cost of production in the long-run.

- The hybrid mean reversion or Integrated (or Inhomogeneous) GBM in which the drift $F(X_t) = \theta.(X_t^* - X_t)$ (mean-reverting drift rate) and the diffusion $G(X_t) = \sigma.X_t$. This process captures both the mean reversion and the price proportional characteristics of electricity prices.

Second, two-factor models build on the previous category and intend to complete the analysis by giving a stochastic behaviour to one of the component of the single factor models, be it from the drift and/or the diffusion (i.e. α, σ, θ and X_t^*): stochastic volatility, stochastic long-term equilibrium price, etc. The component itself becomes a stochastic process represented by a general SDE. This approach also features (1) jump-diffusion models, (2) regime-switching models and (3) attempts to split short-term behaviour from long-term behaviour.

Once the functional form of uncertainty has been decided upon, a critical step is the fitting of the parameters of the function to the source of uncertainty. This can be achieved in three manners:

- Econometrics based on historical observation: this approach attempts to elicit the parameters of functional forms from time series of sources of uncertainty using different statistical methods (ordinary least-squares, maximum likelihood estimation or moment matching methods for instance). It should be stressed that usually at least 30 years of historical data is required in order to properly calibrate a model (Dixit and Pindyck, 1994 [1]; Keppler et al., 2006 [65]). Dixit and Pindyck (1994 [1]) hints at relying on theoretical considerations should this condition not be fulfilled. This is typically a backward-looking way to calibrate prices and hence bear the risk of unforeseen changes in parameters dynamics (regime-switching) or extreme events outside the historical range;

- Specific model output indicating equilibrium prices for commodities. This is a forward-looking way to set the parameters of stochastic processes. Results are highly dependent on the models;

- Expert surveys to elicit future price paths. This is also a forward-looking exercise and academics have developed approaches to factor in specific predictions or ranges thereof into parameters (for an illustration, see Laughton and Jacoby, 1992 [66]).

(4) Irreversibility Finally, under the ROA initial investments are considered irreversible. A limitation of the traditional NPV rule under DDCF is to assume the perfect marketability of assets being valued. This made valuation rather unrealistic when large scale or proprietary investment are performed. Instead, the ROA takes this characteristic into account.

In fact, the problem of choosing the timing of irreversible investment is an optimal stopping problem, i.e. one should invest at a moment when the opportunity cost of delaying the project equals the expected change in its NPV (for further reference see McDonald and Siegel 1986 [67] and Murto 2007 [68]).

Solving real options models

Various methods are envisaged in the real options literature to solve such problems. In particular, Sick and Gamba (2005 [60]) identified four basic computational methodologies for valuing real options.

(1) Closed-form analytic solutions This category is inherited from the financial options literature and therefore only works for the simplest real options types (a single development option equivalent to a call option or a single abandonment option equivalent to a put option). The method used includes the Black-Scholes formulas for European put and call options and solutions for perpetual American put and call options on normally or lognormally distributed underlying assets.

Given that closed-form solutions rarely exist (especially when several sources of uncertainty are considered), alternative methods have been used either to approximate solutions or to discretize continuous underlying processes. The three remaining approaches fall into this category.

(2) Numerical solutions to partial differential equations (PDEs) The analytical approximation methods attempt to solve such problems by finding a closed-form solution to the partial differential equations (PDEs) at the core of the model.

Two equivalent approaches are detailed in the literature. The dynamic programming approach involves breaking down the entire sequence of decisions into two components: the immediate decision and a value function that encompasses the consequences of all subsequent decisions (Bellman approach). The contingent claims approach makes an analogy between the investment considered and a stream of costs and benefits varying through time and depending on the unfolding of uncertain events. Hence, valuation is based on underlying tradable assets. This implies some combination of traded assets that will mimic the pattern of returns from the investment project at every future date and in every future uncertain eventuality. Dixit and Pindyck (1994) [1] explain that both approaches should result in the same solutions (the only differences being the discount rate used and the way cash flow components account for uncertainty).

Nonetheless, this type of approximated solution is rather used by academics than by practitioners as it would require too much resources to build custom PDE solutions for every real options encountered in business.

(3) Lattice, tree and mesh models Following Sick and Gamba (2005 [60]), the lattice approach to evaluating real options involves using a Bernoulli process with up an down jump moves at each step to approximate the stochastic process of the underlying. Three parameters are to be found in the Bernoulli process used to approximate the stochastic process that cannot be solved directly: (1) the size of the up move and its form - additive or multiplicative (for example multiply by 1.05, i.e. 5% increase), (2) the size of the down move[2] and (3) the risk-neutral probability of the up move (from which that of a down move is implied). The smaller the size of the

[2]When the size is equal to that of the up move, we are facing a recombining tree which facilitates computations. But this is not required to resort to this approach.

steps between jumps, the better the approximation. The dynamics of the Bernoulli model is specified into the whole lattice of up and down moves, which provides the investor with a variation of the decision tree. The tree is solved using an optimization technique called the Bellman equation or the principal of optimality in dynamic programming. The Bellman equation recursively computes the optimal real option value by comparing the continuation value to the proceeds of moving to the next state. It provides the investor with both the value of the investment opportunity under consideration and the optimal strategy (i.e. exercise the option at step 5 for instance).

The main advantage of these models is that they are easy to understand and work particularly well for American and European options. When a single of uncertainty is considered, they can be implemented quite straightforward. But when more than one source of uncertainty is considered, solving such models is usually complex and required implementing more code or resorting to numerical programming languages. Lattice, tree and mesh models are plagued by the curse of dimensionality: as more dimensions of uncertainty are featured in the model, many more sub-cases are to be accounted for in the tree, which complicates the solution and the interpretation.

(4) Simulation models Alternatively, Monte Carlo simulations (first employed by Boyle in 1977 [69]) are a numerical integration method that can be used to find a risk-neutral value of an option by sampling the range of integration. This is traditionally a forward-looking technique in contrast to the dynamic programming technique with resorts to backward recursion. Several authors have attempted to combine both approaches in a valuation framework (see the case of an undeveloped oil field in Cortazar and Schwartz, 1998 [70]).

More recently, the development of the least-squares Monte Carlo (LSM) method (a subset of Monte Carlo methods) has allowed to match Monte Carlo simulations and dynamic programming which can be used to price American and Bermudan options (in which case the option can only be exercised at specific dates over its life) featuring several sources of uncertainty. Longstaff and Schwartz (2001) [2] first developed the method in a financial options context with various applications to vanilla options, path-dependent options, multifactor options and complex American swaptions. The idea behind is to estimate the conditional expected continuation value component of the Bellman equation from a simulation of the whole distribution rather than using a Bernoulli lattice. The main contribution of the LSM approach is to compute the expected continuation value for all previous time-steps by regressing the discounted future option values on a linear combination of functional forms of current state variables (Cortazar et al., 2008 [71]). The estimation is performed using ordinary least-squares and by resorting to a choice of basis functions to act as regressors for the estimation process. The method is rather easy to implement and can be retrofitted to handle more complex investment settings. The method is illustrated in the framework in our investment-decision model in the appendix section and in section 3.2.5.

The 2001 seminal paper triggered a strong interest in extending the original paper to new applications (Rodrigues and Armada 2006 [72], Alesii 2008 [73], Areal et al. 2008 [74]). In particular, several robustness or calculation tests have been performed for: (1) various types of stochastic processes with a higher number of dimensions, (2) various number of discretization points, simulated paths and basis functions, (3) various types of basis functions (not only Laguerre polynomials as in Longstaff and Schwartz (2001) [2]) and (4) regression algorithms (different from ordinary least-squares). Closed-form (when available) or lattice solutions have been used as benchmarks in all those tests and results indicates that the LSM algorithm is quite robust, solutions are quite close from benchmarks and computation speed is good.

In 2003, Gamba [3] and then Rodrigues and Armada (2006 [72]) transposed the LSM approach to real options problems with interacting real options, several state variables, etc. Cortazar et al. (2008, [71]) applies the LSM approach to the valuation of multidimensional American real options - namely, the Brennan and Schwartz (1985 [58]) paper on natural resources investment and an expansion thereof with a three-factor stochastic process for the price of copper. Again, it is found that results from LSM simulations compare well to those from finite difference methods.

Applications to power plant valuation

Common applications for the ROA in the academic literature are high capital cost investments (oil fields, mines, power plants, etc.) characterized by large uncertainties in demand, supply and/or price (natural resources and R&D projects especially), long lifetime and some leeway or strategic behaviour either in the initial investment decision or subsequent operating decisions.

In this respect, the very characteristics of power plant investment decisions make it particularly relevant to use the ROA. As usual with the real options approach, three elements are particularly looked at: the overall value of an investment, specific option value(s) and the optimal behaviour (chain of decisions that will reap the maximum value out of an investment opportunity).

The ROA has been applied to a large variety of specific issues related to power plants like peak-load power plant valuation, hydro power plant valuation (taking into account the flexibility in managing the water level in its reservoir), fuel switching in IGCC plants or CHP plant optimal output scheme (heat vs. electricity).

In this section, we provide a literature review on power plant valuation using the real options methodology, which highlights the evolution from single investment valuation and comparative investment valuation to investment planning and technology deployment. When undertaking this survey, we will keep in mind our hypotheses to test and the model we will detail afterwards.

(1) Single investment valuation Single investment valuation focuses on providing a fair value for a given power generation asset typically improperly valued using DDCF. Among the major papers, Deng et al. (2001 [75]) propose a methodology to value generation assets by constructing replicating portfolios from electricity futures and a risk-free asset. The model identifies that the right to operate a generation asset is given by the value of a spark spread option with a strike price corresponding to the heat rate written on a generating fuel. It is suggested that the method generates reasonable estimates of the actual value of the assets (compared to recent transactions) and more accurate than with a traditional DDCF approach.

In contrast to the then-prevailing purely financial approach to valuing real assets, Tseng and Barz (2002 [76]) incorporated physical constraints in the short-term modelling of a power plant (unit commitment constraint with a ramp-up time and an associated cost). The method suggested is an integration of a backward-moving dynamic programming with a forward-moving Monte Carlo simulation. It is shown that failure to consider physical constraints may significantly overestimate the value of the plant. The method used is quite flexible and can accommodate additional price processes and new uncertainties even though it requires massive computations.

In the same vein, Deng and Oren (2003 [77]) incorporated operational characteristics and start-up costs in the valuation of a power generation asset. Generators are modelled as a strip of cross commodities call options (spark or dark spreads) with a delay and cost imposed on each option exercise. In contrast to Tseng and Barz (2002 [76]), the stochastic prices of electricity and fuel are represented by recombining multinomial trees. They find that the more the efficient the power plant is, the less its valuation is affected by operational constraints (and vice versa).

Hlouskova et al. (2005 [78]) studied the unit commitment problem of an electricity producing turbine using the Tseng and Barz (2002 [76]) model and specifically taking into account: (1) price uncertainty captured by a mean-reverting process with jumps and time-varying means to account for seasonality and (2) operating constraints for the turbine. Compared to previous literature, they provide a more complex modelling of the price uncertainty. In addition, the model is adapted to compute the risk profile the turbine. More recently, Abadie and Chamorro (2006 [79]) applied real options valuation to a natural gas-fired power plant using a least-squares Monte Carlo approach accounting for several sources of uncertainty and constraint (construction lead-time, etc.).

In the model we develop later on in this chapter, we will not incorporate (1) short-term operational flexibility (increasing value) and (2) physical & operational constraints (typically decreasing value). The reason why is that we will be focusing on exploring the value of generation portfolios where the big picture matters most, not asset- or market-specific characteristics. Yet, we acknowledge that individual investment valuation might be affected.

(2) Comparative investment valuation A second strain of ROA applications to power generation assets focuses on the comparative valuation of one asset against one another. This strain of research typically answers questions like when / under what conditions would an investor favour one generation technology over another. This is especially performed in the light of internal (flexibility of an asset) and external factors (exposure to market prices or hedge).

Frayer and Uludere (2001 [64]) compare the value of two generation assets in the Northwest region of the USA facing volatile power prices. Using the ROA, they find that the peaking gas-fired plant may be more valuable than the mid-merit coal-fired plant, even though the traditional DDCF approach would favour the latter given its lower marginal cost. A flexible generating plant can be modelled as a string of European call options on the spread between electricity prices and variable cost (see Table 3.11 adapted from Frayer and Uludere, 2001 [64]). In particular, the difference is explained by the peaking plant ability to ramp up and down in function of the market environment.

Table 3.11: Financial vs. real options terminology

	Real options
Underlying asset	Power
Value of the underlying asset	Expected price of power
Exercise price	Expected variable cost of production (like fuel cost)
Time to maturity	Each hour in the plant's useful life
Uncertainty	Spark-spread volatility
Risk-free rate	US Treasuries interest rate

Murto and Nese (2003 [80]) explore the choice between a fossil fuel plant with a stochastic fuel price (modelled as a GBM) and operational flexibility (it is possible not to operate at unprofitable market conditions) and a biomass-fired plant, which price is assumed constant. Using methods developed by Dixit and Pindyck (1994 [1]), they find typical results from the real options methodology. Namely that (1) the lower the fossil fuel price, the more attractive the investment in the fossil fuelled plant (and conversely the higher the price, the more attractive the biomass plant) and (2) increased uncertainty in any price process would expand the waiting region (i.e. delay the investment decision).

Epaulard and Gallon (2001 [81]) apply real options methods to value the European Pressurized Reactor (EPR) project in France in comparison to a CCGT with long-term natural gas contracts providing a hedge against a price increase. Otherwise, the price of natural gas is assumed to follow a GBM stochastic process. Of particular interest is the option value associated with building an EPR prototype as early as in 2000 that would allow subsequent investment in commercial EPR technology in 2015 (2-step decision). Sensitivity tests indicates that (1) increases in the discount rate reduce the attractiveness of the EPR investment, (2) the alternative of incurring rejuvenating expenses for older nuclear power plants may delay the EPR investment decision.

Näsällälä and Fleten (2005, [82]) compare two CCGT plants - a peakload power plant able to ramp up and down according to price change and a baseload plant which produces electricity independent of the spark spread. The spark spread is modelled as a two-factor stochastic process: the sum of a short-term deviation stochastic process (following an Ornstein-Uhlenbeck process) and an equilibrium price stochastic process (arithmetic Brownian process). First, a decision is made on the technology of choice. Second, in case the baseload was first favoured it can be upgraded afterwards to a peakload plant. They find that an increase in the volatility of the spark spread (i.e. the uncertainty considered) has an ambiguous effect on the investment decision. On the one hand, it increases the value of the peakload plant rendering such plants more attractive. On the other hand, uncertainty also delays any investment. Using a numerical simulation, they attempt to disentangle the two effects. It is found that an increase in short-term variations hasten investment decisions, while an increase in long-term variations delays investment decisions (which is rather intuitive due to the mean-reverting behaviour of short-term variations).

For our investment model, we keep modelling insights for comparative investment valuation from this strain of literature. We also follow Näsällälä and Fleten (2005, [82]) attempt to disentangle short-term effects from long-term effects (short-volatility of the carbon price versus changes in the growth rate of the carbon price longer-term trend in our case). Yet, we extend the break-even analysis between two assets to a more elaborate optimization procedure for various technologies under budget constraint.

(3) Investment planning / technology deployment A third strain of papers look at multiple technologies in a longer term. Our model is closer to that strain of papers. Madlener et al. (2005[83]) explore the adoption of generation technology in the Turkish power sector using a dynamic technology adoption model aiming at maximizing a combined NPV under uncertainty and with flexibility in the timing of adoption (optimal stopping problem solved by dynamic programming). In particular, vintage-specific life-cycle capital, requirement to fulfil the uncertain demand and operation costs are taken into account. Nonetheless, model results are quite different from empirical evidence over 1970-2000 (CCGTs instead of lignite-fired plants with lignite being the domestic fossil fuel source). We retain the flexibility in investment timing developed in this paper but do not consider vintage-specific capital nor learning curves as this would entails projecting technology cots over a ten-year window.

Finally, Kumbaroglu et al. (2005[84]) suggest an investment planning model for renewable power technologies with real options embedded. Learning curve information, power and fuel price stochastic uncertainty and demand uncertainty featured in the model. It is shown that because of their relative high costs, the diffusion of renewable energy technologies only occurs if targeted policies exist. In particular, policies aimed at increase the share of renewable power generation and short-term financial incentives (Kyoto protocol CDM or JI mechanisms notably) can help deploy such technologies. We will perform sensitivity tests to ETS-related policies in our model.

Applications to power plant valuation and climate policies

Now, we explore the literature dedicated to ROA valuation of power generation assets in the face of climate mitigation policies. Four broad groups of paper are to be found: papers looking at the option value of operational flexibility when facing revenue-eroding mitigation policies, papers attempting to quantify climate policy risks, papers performing comparative / relative valuation of generation assets and papers dedicated to investment planning.

(1) Specific option value for flexible generation technologies A typical real option result is that operational flexibility adds value to a specific investment. This value-added is the option value. Volatile market prices or uncertainty increase the option value. This group of papers look at this extra value. Laurikka (2005 [85]) applies the ROA to estimate the impact of the introduction of the EU ETS on the option value of gasification technology in Finland. He resorts to a simulation model (similar to Laurikka and Koljonen, 2006 [86] but able to deal with multiple stochastic variables) in which a single firm aims at maximizing its NPV. The author finds that the IGCC technology is not yet competitive in power plant retrofits within the EU ETS (current investment cost still too high). Additionally, he highlights that the value of a preparation investment to the potential later use of the IGCC technology (compound option) was still too high - if it were lower, the ROA would favour such investment (while traditional DDCF would not). Given our choice to focus on the big picture and this paper's conclusions, we ruled out IGCC from our basket of available technologies. Moreover, while preparation investment are interesting, we do not focus on these in our model.

Abadie and Chamorro (2008 [87]) study the case of CCS investment on a coal-fired plant in Spain. The investor is exposed to uncertain carbon and power prices. Employing a two-dimensional binomial lattice to derive the optimal investment rule solves the model. In particular, they elicit the carbon price required to trigger the retrofitting of existing coal-fired plants with CCS units. They find that current permit prices do not provide an incentive to the rapid adoption of the CCS technology and that a price close to EUR 55/ton is required. Should carbon price volatility be significantly reduced (from 47% to 20% on annual basis) the trigger price would drop to EUR 32/ton. Even with a 100% government support for the CCS units, the trigger price would only drop to EUR 42/ton, still quite remote from the then-prevailing prices. We will elicit such price thresholds in our model to switch from one technology to another.

(2) Investment risk quantification The second group of papers quantifies the impact of climate policy uncertainty on investment risks using ROA. Yang and Blyth (2007 [88]) describe the IEA model (IEA's MINUIT model[3]) to investigate the implications of uncertainties for investment decisions, including carbon price. The model allows for multiple sources of uncertainty and can be adapted to value option-free models (i.e. both deterministic and stochastic discounted cash flows), basic option models (i.e. timing option), multiple options, multiple options with probabilities and compound or nested options (i.e. option within an option like option to invest in a CCS prototype that would create an option to build commercial scale CCS units later on for instance). The energy prices modelling explicitly allows jumps (contrary to instance from Laurikka, 2005 [85]). Still, the model do not account for capital constraint and consider only one technology at a time. These are two improvements we will add with the model discussed in

[3]Short for Modelling Investment with Uncertain ImpacTs.

the next section.

(3) Compared investment valuation The third group of papers examines the relative changes in valuation of competing generation technologies with climate policies. Laurikka and Koljonen (2006 [86]) evaluate the effect of the introduction of the EU ETS on power plant investment decisions in Finland (coal-fired vs. gas-fired plant). Two flexibilities are accounted for: the option to wait on the one hand and the option to alter the production scale on the other hand. The model is solved using a Monte Carlo simulation *à la* Deng and Oren (2003, [77]). While we keep the timing option suggested in this paper, we will use a constant production scale to focus on our question of generation portfolio rather dive into operational or design details. In contrast to the other papers in the literature, the ability to sell allowances in excess of compliance needs is introduced in this model. We will not replicate this specific considering the trend towards more auctioning in the EU ETS where carbon trading would be less the results of an initial allocation but rather a regular adjustment process. Moreover, we do not expect that profit and losses from carbon trading activities be significant. The main point of Laurikka and Koljonen (2006 [86]) paper is to show the improvement induced by the ROA to value generation assets facing climate policy uncertainty.

Sekar (2005 [89]) applies the ROA to better understand the impact of CCS technologies on coal-fired power plants. He considers three technologies: a pulverized coal plant (expensive subsequent CCS retrofit), a baseline IGCC (relatively less expensive CCS retrofit) and the capture-ready IGCC (relatively cheap CCS retrofit). The paper suggests that there is substantial economic value to temporal flexibility in the retrofit decision-making. This value increases with that of CO2 price uncertainty, a typical real options result. The pulverized coal plant is the most-favoured alternative while capture-ready IGCC is the least-favoured. Our model considers two of these coal-based technologies (pulverized coal plant with and without CCS).

Fuss et al. (2008 [90]) compare the attractiveness of coal-fired plant investment vs. coal-fired plant with CCS in the light of uncertain climate policy. In particular, they consider two forms of carbon price-related uncertainties: (1) a market-driven price volatility around a mean price (market uncertainty) and (2) bifurcating price trajectories mimicking uncertainty about changing policy regimes (policy uncertainty). The model is solved using forward Monte Carlo simulation. Relatively similar to Näsällälä and Fleten (2005, [82]), they identify two contradictory effects at play in the model. On the one hand, the investor facing market uncertainty about CO2 prices invests into carbon-savings technology (i.e. with CCS) earlier than if the actual price path had been known beforehand (result optimizing under imperfect information). On the other hand, policy uncertainty induces the investor to wait and see whether its government will commit to climate policy (typical real options effect). Which effects is the stronger depends on the relative value of learning about government commitments and the value of investing immediately (as a hedge). They conclude that the carbon price uncertainty is more harmless from an environmental and financial point of view than the policy uncertainty. We will test similar trade-offs with our model.

Szolgayova et al. (2008 [91]) assess the impact of introducing carbon price caps on power generation investments. They present the case of a power producer, who consider replacing existing coal-fired capacity with either (1) coal-fired capacity that can be extended to include a CCS module or (2) a biomass-fired power plant. The model used is similar to Fuss et al. (2008 [90]). The paper shows that price caps set at too high a level are detrimental to the adoption of modern biomass-fired capacity. In addition to that, they indicated that even for moderately rising carbon prices, carbon price uncertainty frequently leads to investment into CCS, while investment is not triggered in the face of deterministic CO2 prices (a typical real option result).

(4) Investment planning / transition mapping The last group of papers broadly named "transition mapping" considers the optimization of investment choices in multiple technologies over a long time horizon. Fuss et al. (2009 [92]) explore the impact of climate policy uncertainty on the adoption of power generation technologies over a very long time horizon of 150 years. The technologies considered are coal-fired plant without CCS, with CCS and wind power. The model features timing flexibility. Capital is not divisible in the model (only one choice at a given time), which is something we added to our model. The model is solved using a blend of Monte Carlo simulation and stochastic dynamic programming. The paper indicates that the larger the carbon price uncertainty, the larger the cumulative CO2 emissions over the planning horizon. We will not follow such a long-term planning horizon for investment especially given potential technical progress and learning curve effects that would most likely occur. They conclude that it is better from an environmental point of view to have climate policies that are stable over a certain length of time and change abruptly than less abrupt but more frequently changing policies.

3.2 Presentation of the investment decision model

In the previous section, we reviewed the state of the art in capital budgeting academic research. It was highlighted that a typical NPV analysis helped answer questions like "what is the value of an investment?" or "should someone invest in this project?".

Yet, these questions did not reflect what was exactly on the investor's mind. First, the investor is interested in realizing the maximum value of the investment (flexibility and uncertainty factored in both the valuation and investment criteria). The DDCF approach and NPV criteria used in a typical framework do not account for these. Second, the investor is interested in *how* that maximum value can be attained. The DDCF approach neither provides flexibility in the decision-making process nor gives insight on how best to realize the value. In both cases, the ROA helps answer those questions which are critical in the face of climate policy uncertainty: what is the value of power plant exposed to climate policy uncertainty? What investment decisions are taken (timing and technology) given investor's expectation?

In this section, we present the multivariate real options framework we will be using in the remainder of this chapter. Research objectives are the following:

1. Resort to a more realistic approach to corporate investment decision-making;

2. Highlight typical investment decisions undertaken within this framework and corresponding generation portfolios;

3. Identify policy levers that the policy-maker can ultimately use to provide a better incentive to prevent locking-up tons of carbon over power plant lifetimes.

We consider the case of a fictional European utility company that has a 10-year window to invest in a combination of various generation technologies: nuclear, CCGT, pulverized coal with and without carbon capture and storage (CCS) and offshore wind generation.

We assume a European utility operating over the French-German area. The utility has been approved to build and operate power plants on a given number of sites. Until expiration of the licenses to build for the sites (10 years from now), the utility has flexibility in (1) when to build power plants (timing option) and (2) what power generation technologies to invest in. We assume that the utility is exposed to French power market prices. This allows us to consider nuclear technology as a generating technology (while in the case of Germany that would not have been possible because of the post-Fukushima phase-out of nuclear generation).

The model specifically accounts for uncertainty in carbon and power prices and incorporates capital rationing in the real options investment decision framework to reflect (1) a portfolio-like decision-making on the part of utilities (at some point, investment valuations in addition to being performed on a case-by-case basis are factored in a portfolio of holdings and how they would fit in that portfolio is critical) and (2) the capital expenditures earmarking in the European utilities business (i.e. assigning target capacity increase over time to various business units, technologies, countries and markets).

The utility investor is assumed to be either a genuine new entrant in the EU ETS or an incumbent investing in a new installation. Accordingly, some power plants could be eligible to the new entrant reserve (NER) which puts aside EUAs for new participants in the scheme. Still, it was assumed in the initial calibration of the model that there were not any allowances left in the NER so that EUAs have to be purchased to initiate plant's operations in order to reflect the forthcoming situation of investors facing the auctioning of EUAs on a more systematic basis[4].

3.2.1 Model structure

The objective of the model is to solve an investment decision problem under uncertainty. The shift towards more liberalized markets with several policy instruments triggered regained interest in electricity market modelling. Such interest revolved around three major trends (Ventosa et al., 2005 [93]): optimization models, equilibrium models and simulations models. To some extent, our approach belongs to the first trend given our focus on a single firm trying to optimize its investment plan under exogenous price developments. We resort to a least-square Monte Carlo real options approach in order to account for multiple sources of uncertainty (carbon and power prices uncertainty), flexibility in the decision-making process and the ability to retrofit the main methodology to consider soft capital rationing practice. We use a discrete time mixed state real options decision model. In our problem, the state space is mixed (i.e. some states are continuous while others are discrete) while the action space is discrete. See figure 3.5 for a decision

[4] Note that since we mainly focus on the carbon price uncertainty, we are not taking into account power demand uncertainty, the impact of competition moves on market prices (by addition or removal of capacity), technical progress, transmission and network constraints (which to some extent, we acknowledge, might be critical for the valuation of intermittent sources of electricity).

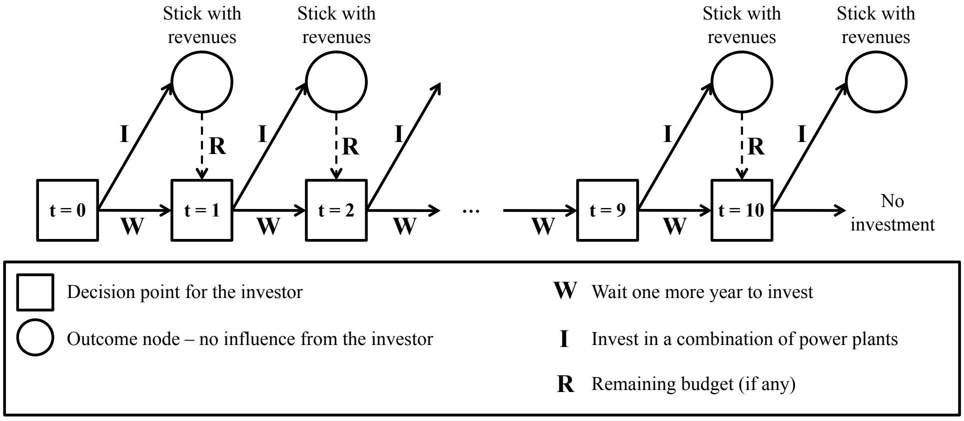

Figure 3.5: Model structure

tree representation of the model. In every period $t \in \|0; 10\|$, the investor[5]:

- observes the state of various economic processes: (1) the remaining internal budget (b_t), (2) stochastic prices for carbon (p_t^c) and electricity (p_t^b for baseload and p_t^p for peakload) and (3) deterministic prices for the feed-in tariff of the offshore wind farm (p_t^f) and for fossil fuels, namely coal (p_t^k), and natural gas (p_t^g). We use S_t as the set of price state variables (excluding the budget level).

- decides to (1) invest in a combination of power plant technologies (a CCGT power plant costing I^G, a pulverized coal plant without CCS for I^K, with CCS for I^C, a nuclear power plant for I^N and an offshore wind power plant for I^W) or (2) wait to invest later as long as the site license has not expired and the budget permits. The decision is indicated by the control variable x_t (the scope of actions depending on the remaining budget).

- earns a reward $f_t(b_t, x_t, S_t)$ in the form of the NPV of the investment undertaken that depends both on the states of the economic processes and the action taken at a given time t.

The investor seeks a "policy" of state-contingent actions $(x_0^*, x_1^*, ..., x_{10}^*)$ that will maximize the present value of current and expected future rewards,

[5]A typical approaches to ROA power plant valuation involves directly modelling the spark spread (the power generator profit margin per MWh) as the sole underlying process (and often as a mean-reverting process or inhomogeneous geometric Brownian motion). Given that our focus is on carbon price uncertainty, we will not model clean spark spreads or clean dark spreads but rather model power and carbon price processes as distinct processes. That way, we can use the same price processes to value nuclear and wind investment alternatives and we can better observe the economic relationships between carbon and power prices.

discounted at a per period factor e^{-r}:

$$\max_{x_t(.)} \; [\mathbb{E}_0^Q \sum_{t=0}^{10} e^{-r.t} f(b_t, x_t, S_t)]$$

Note that $\mathbb{E}_t^Q[\tilde{S}_{t+1}]$, indicating the risk-neutral expectation about the future set of stochastic state variables (S_{t+1}) conditional on knowing S_t (also known as the Equivalent Martingale Measure or EMM), is equivalent to $\mathbb{E}^Q[\tilde{S}_{t+1} \mid S_t]$. We resort to the former notation for the sake of readability. Also note that $\tilde{S}_t$ indicates that the set of stochastic state variables is actually random in time t as opposed to S_t which indicates it is known.

The use of a risk-neutral pricing framework allows us to use a risk-free rate for discounting purpose instead of having to determine a risk-adjusted discount rate that would be bluntly applied to all cash flows whatever the risk embedded (feed-in tariffs would therefore implicitly be assumed as risky as the carbon price).

Finally, like in Szolgayova et al. (2008 [91]), we assume that the investor is a price taker, who supplies electricity inelastically.

3.2.2 State variables used in the model

State variables represents observable and expected value of economic parameters. We consider the carbon price, power prices, the remaining capital expenditures earmarked for power generation and the price of fuels.

(1) Carbon stochastic prices modelling

Survey of carbon price modelling Recent empirical papers help explain the evolution of past prices on the European carbon market. In particular, Alberola et al. (2008) [94] and Mansanet-Bataller et al. (2007) [95] have shown that carbon prices reacted to energy markets price developments (power, oil, natural gas and coal), extreme temperatures (i.e. significantly beyond or below long-term averages) and industrial activity. Alberola and Chevallier (2009) [96] have identified that market participants would engage in intertemporal adjustments allowed by the market design of the EU ETS. Mansanet-Bataller and Pardo (2009) [97] demonstrate European carbon prices' high sensitivity to institutional announcements resulting in price shifts upon or prior announcements. Benz and Trück (2008) [98] have identified stylized facts of European carbon prices: mean-reversion, jumps and spikes, and heteroskedastic volatility (clustering volatility).

Although definitely a place to look at for guidance, the relatively short carbon price history makes it difficult to solely rely on this literature for investment decision-making - a prospective task by nature. The choice of the relevant approach for modelling the carbon underlying asset must help in the long-term irreversible decision making. Still, those price drivers and stylized facts help the decision maker choose the proper carbon price modelling and parameter fitting.

Therefore, we resort to a stochastic price model to account for uncertainty in European carbon prices. We model the carbon price as a continuous state stochastic variable. This means that the investor does not know what the future prices will be (that would be a deterministic variable instead) but does know the price process and fitting parameters used and hence the statistical distribution associated. This approach involves using a mathematical depiction of the price dynamic for carbon, that is subsequently calibrated and then used to simulate price paths ultimately used in generation technologies valuation and investment decision-making.

The two main processes for carbon price found in the literature on investment decision under carbon price uncertainty so far are (1) the Geometric Brownian Motion (GBM) which is the price process basically used for stocks and (2) a typical mean-reverting (MR) process, the Ornstein-Uhlenbeck model. Those price processes are sometimes completed by adding jumps to the processes to reflect abrupt changes in climate policy[6]. Table 16 in the annex surveys price processes used for carbon prices found in the literature as well as fitting methods and data used.

Most authors have resorted to the GBM form to model the price of carbon. This is the typical form chosen for equity prices in option pricing model and which implicitly makes an assumption of exponential price growth. In a policy-oriented study of investments under climate policy uncertainty, Blyth et al. (2007) [100] and Yang et al. (2008) [101] model the price of carbon as a GBM. Yang and Blyth (2007) [88] further improve their modelling of carbon price by simulating possible carbon price shocks that would represent policy-related events by adding a jump feature to the stochastic modelling (only once ten years from when the initial investment decision can be first taken). The GBM is fitted using a mix of IEA projections and judgemental input.

[6]Other authors have suggested other functional forms for carbon price modelling taking into account more detailed price movements like price spikes or regime switching. But those stochastic modelling are not initially done for investment decision where the big picture matters the most but rather for derivatives pricing or short-term valuation purpose. See for example, Benz and Trück (2006) [98] for an application of regime-switching models and Daskalakis et al. (2007) [99] for applications of jump-diffusion models.

In an application to optimal rotation period for forest valuation, Chladná (2007) [102] resorts to a GBM fitted with the IIASA MESSAGE model[7]. Szolgayova et al. (2008) [91] and Fuss et al. (2008) [90] assume that, while the electricity price is suggested to follow a mean-reverting process, the carbon price follows a GBM process. Again, the data used to parameterize the GBM comes from IIASA's GGI Scenario database and originally refers to the shadow price of emissions. Fuss et al. (2009) [92] use the same GBM to model the price of carbon but also add a jump process to reflect policy changes over a very long-term horizon (150 years). The size of jumps are drawn from an underlying GBM.

Abadie and Chamorro (2008) [87] resort to a stochastic model of carbon prices to evaluate the prospects of carbon capture investments in Spain. While all the other papers surveyed have been fitted using either model projections or judgemental input, they model carbon prices using a a typical GBM fitted with EU ETS futures contracts data. Hence, they provide a risk-neutral version of GBM functional form explicitly taking into account a futures market risk premium. They estimate the parameters using a Kalman filter procedure with EUA futures prices between January 2006 and October 2007.

In the literature, the choice of a mean-reverting price model is an alternative to the GBM which has the drawback to allow wider price developments over time (the variance of which grows infinitely) than mean reverting models. While models based on GBM have been used for tractability and ability to obtain closed-form expressions, mean reversion reflects the long-term equilibrium of production and demand. Laurikka and Koljonen (2006) [86] model the natural logarithm of the price of carbon allowances as a simple mean-reverting Ito process, namely an Ornstein-Uhlenbeck process (continuous state and discrete time). The authors assign two different values to the long-term price level (by 2013) depending on the scenario taken: EUR 20/ton in a high scenario and EUR 1/ton in a low price scenario. Similarly, the variance parameter can take the value of 10% (low volatility scenario) or 40% (high volatility scenario). For fitting the model they use a starting price of EUR 7/ton based on early forward transaction prices reported by Point Carbon in 2004. Laurikka (2005) [85] suggests a simulation model which can simultaneously deal with multiple stochastic variables (emission allowances, electricity and fuels) to estimate the value of flexibility. Again, the stochastic processes used in the simulation mimic the simplest mean-reverting process (the Ornstein-Uhlenbeck process). It is important to remark that both stud-

[7]Model for Energy Supply Strategy Alternatives and their General Environmental Impact - a systems engineering optimization model used for medium to long-term energy system planning, energy policy analysis, and scenario development.

ies were designed prior to the entry into force of the EU ETS or at its very beginning.

Stochastic process retained for carbon When it comes to modelling the price of carbon, we contend it is more judicious to model the price of carbon as a mean-reverting process along a (log-linear) trend for three main reasons[8].

First, we argue that carbon price long-term price drivers (the supposedly declining cap feature of the cap-and-trade policy, economic cycles oscillating around a long-term economic growth trend and technological abatement options availability) are such that a mean-reverting process around a trend makes sense.

Second, even though there is no directly observable mean-reverting level as such, it is expected that stakeholders actions should ensure not much price deviation from long-term equilibrium (as would be implied by modelling the price of carbon as a GBM for instance). On the one hand, there are forces that would strive to prevent the price of carbon from reaching extremely high level. Too high a price is the sign of a cap level hardly compatible with a healthy economic activity[9]. On the other hand, there are forces eager to see the price of carbon reach a minimum threshold[10]. As such, market phases negotiations are the occasion to "reset" the rules in order to adjust any fundamental flaw in the market design (like the implied ban on banking decision between phase I and II during the trial phase of the EU ETS). This is achieved on the regulator side by modifying the cap and other elements of policy design (flexibility, exemptions, etc.). On the regulated side, lobbying,

[8] Of course, it is ultimately each decision maker's task to resort to the price process he deems the most appropriate. The same comment applies to the fitting of the process retained.

[9] The effect on the economy and society could be disruptive (insufficient power generation capacity, loss of international competitiveness for industries subject to carbon leakage, etc.). There exist a non-observable upper bound for the price of carbon reflecting the acceptability of compliance buyers above which their survival would be at stake (exit threshold).

[10] In this respect, policymakers (at both the EC and EU Member States levels) are urged to implement successfully the policy to justify their legitimacy to act as such. So are the politics who mandated the regulators and the international community pressuring the EU Member States to respect the commitment to reduce carbon emissions. NGOs, think tanks and carbon market observers would monitor the evolution of carbon price and would publicly advocate for environmental consciousness in case things go wrong. Carbon-reducing and carbon-neutral technology developers are eager to keeping the incentive to maintain the development of such technologies and ensuring commercial prospects thereafter or own compliance prospects. Finally, regulated entities themselves would push for meaningful carbon prices as a way to establish barriers to entry or at least increase the cost to enter the market.

pressuring and legal challenges have been employed.

Third, commodities have often been modelled as MR processes (Pindyck, 1999 [103] and Schwartz, 1997 [104]) allowing to reflect some long-term cost of production, extraction or abatement.

We now turn to the carbon price modelling retained. Let p_t^c denote the price of a carbon emission allowance (in EUR/tCO_2) at time t. We assume that the p_t^c is a continuous state stochastic variable following an exogenous mean-reverting continuously-valued process with a linear trend and constant volatility (similar to the one-factor model based on the log spot price from Lucia and Schwartz, 2000 [105]):

$$\begin{cases} ln(p_t^c) & = h_t^{c*} + X_t^c \\ h_t^{c*} & = \alpha^c + \beta^c.t \quad \text{(linear deterministic trend)} \\ dX_t^c & = -\theta^c.X_t^c.dt + \sigma^c dW_t^c \end{cases}$$

In this price representation, the log of the carbon price is expressed as the sum of (1) a predictable deterministic function of time (h_t^{c*}) and (2) a diffusion stochastic process (X_t^c) in which:

- θ^c is the constant mean reversion speed for the log of the carbon price;
- $h_t^{c*} = \alpha^c + \beta^c t$ is the linear deterministic trend for the log of the price of carbon (not a constant as in the Ornstein-Uhlenbeck model);
- σ^c represents the constant volatility of the instantaneous log-price variation;
- W_t^c is a standard Brownian motion for the log of the carbon price (providing unexpected price shocks).

The linear trend component for the price of carbon can be interpreted as the long run cost of reducing carbon emissions in the EU ETS (evolving over time). In our model, this should therefore reflect cost from future demand for abatement and future abatement options available in the marginal abatement cost curve.

Given our risk-neutral framework (see section 3.2.1), we express the price of carbon according to:

$$\begin{cases} ln(\hat{p}_t^c) & = h_t^{c*} + \hat{X}_t^c \\ h_t^{c*} & = \alpha^c + \beta^c.t \quad \text{(linear deterministic trend)} \\ d\hat{X}_t^c & = \theta^c.(-\lambda^c.\frac{\sigma^c}{\theta^c} - \hat{X}_t^c).dt + \sigma^c d\hat{W}_t^c \end{cases}$$

Where the market price of risk for carbon, λ^c, is assumed to be a constant and the hat superscript used here denotes the move from the real world to the risk-neutral world.

Calibration of the stochastic process The literature shows that the calibration of the carbon price processes is a mix of inputs from econometric analysis of historical data, model output (like the IIASAs GGI Scenario database) and judgemental input be it a shadow price (*valeur tutélaire du carbone* in France for instance [106]) or academic and professional expert price elicitation surveys (like in Sekar, 2005 [89] and Bohm et al., 2007 [107]).

In our case, the non-availability of at least some 30 years of carbon and power prices history prevents us from obtaining a reliable econometric calibration. Still, we decide to fit the price of carbon using the relatively short price history. We decide that the initial parameters estimated would constitute our base case. Later, we will look at the sensitivity of the investments decided upon given the parameters. We will discuss the economic meaning around those parameters in the later section on parameter sensitivity study.

Following Fusai and Roncoroni (2008) [108], we fit the mean-reverting carbon price with futures market data over three years. Once discretized, the process will depend on ϵ_t which is an independently and identically distributed (over time and independent of preceding states and actions) normally-distributed (0, 1) exogenous shock. That is equivalent to saying that the state of the carbon price in period $t+1$ will depend on the state in period t and an exogenous random shock ϵ_{t+1} that is unknown in period t. The carbon price model is estimated by maximum likelihood. The log-likelihood function is computed by discretizing the mean-reverting process through the Euler method and solving for the log price:

$$ln(p^c_{t+\Delta t}) = ln(p^c_t) + \theta^c[h^{c*}_t - ln(p^c_t)]\Delta t + \sigma^c\sqrt{\Delta t}\epsilon_t$$

Recall that ϵ_t is a random draw from a standard normal distribution $N(0,1)$. The resulting variable has a normal conditional distribution given by:

$$ln(p^c_{t+\Delta t} \mid p^c_t) \sim N(m_t, v_t)$$

Where:

$$m_t = ln(p^c_t) + \theta^c(h^{c*}_t - ln(p^c_t))\Delta t$$

$$v_t = (\sigma^c)^2\Delta t$$

We set $\Delta t = 1/255$[11] and obtain the following expression for the log likelihood function with daily observations:

$$lnL = -\frac{1}{2}\sum_{i=1}^{n}[\frac{(ln(p^c_{t,i}) - m_{t,i})^2}{v_{t,i}}] - \frac{1}{2}ln(v_{t,i}) - \frac{1}{2}ln2\pi$$

By maximizing this quantity with respect to parameters $\alpha^c - \lambda^c$, β^c, θ^c and σ^c, we obtain a statistically estimated model for the carbon price dynamic. Data stems from ECX carbon futures contract for delivery in December 2010. This data set (1,371 observations) covers almost five years and a half from April 22nd, 2005 to August 24th, 2010. Figure 3.6 illustrates the price of carbon over the sampling period. The parameters chosen are to be found

Figure 3.6: EUA futures price 2010 (ECX) - in EUR/tCO2

in Table 3.12. Apart from β^c, which was negative (-0.0944) and implied

Table 3.12: Parameters for the carbon price process

α^c	Average level	3.1890[12]
$\beta^c - \lambda^c$	Linear growth	0.0250
θ^c	Mean reversion force	2.4474
$(\sigma^c)^2$	Instantaneous variance	0.1900

[11] Average number of trading days on ECX, the marketplace with currently the largest volume of transaction and which data we used to calibrate the price process.

[12] Equivalent to EUR 20.80 by taking the exponential.

that the price of EUA would crash in a few years, we used results from the econometric calibration. Instead, we used a positive growth rate that would be used for our base case calibration. We set the growth factor at 0.025 consistent with a target price of EUR 40 by 2030 - which is in line with market analysts price projections over the sample period.

(2) Power stochastic prices modelling

The literature on the stochastic modelling of electricity prices (Geman, 2006 [63]; He, 2007 [49]) identifies that power prices share the following characteristics:

- High spot price volatility and volatility clustering effect (periods of high volatility tend to be followed by similar periods);
- Mean reversion to the marginal cost of production (like most commodities);
- Seasonality (intraday, weekly and annual);
- Price jumps reflecting supply shocks (power plant outage) or unexpected demand;
- Market-specific prices (reflecting the existing generation mix, demand profile and incentive policies).

These characteristics pertain most to spot prices. With forward or futures contracts, the width of these effects tend to be softened or disappear the longer the maturity.

Given that the spot market in Europe is almost exclusively an adjustment market (the real options literature involving spot power prices reflects largely a focus on derivatives pricing), we assume that the power plants that would be built would sell their production using exclusively forward transactions. This seems a reasonable assumption in light of calendar contracts liquidity on market places and market practice as indicated by European utilities annual reports[13].

While the price of a ton of carbon is *de facto* EU-wide, it is not that simple for the price of a MWh generated and sold. The price of a MWh fundamentally depends on the power plant status in the generation merit order related to a given demand source (country- or grid-wide) and for a given

[13]For instance, RWE financial statements for 2008 indicate that, in fiscal year 2008, the utility actually hedged nearly 100% of its expected power production for 2009 and approximately 70% for 2010 (by selling power using forward transactions).

time. Given the power plant investment options suggested in the next section and more exactly the capacity, availability and competing power plants, plants should either operate as peakload or as baseload plants. In our modelling environment, we assume that the CCGT, pulverized coal plants with and without CCS would operate as peakload plants and sell their power generation at peakload prices (p_t^p).

Conversely, the nuclear plant would operate as a baseload plant and sell its power generation at baseload prices (p_t^b).

Additionally, the sale of power generated by renewable energy sources often benefits from an support mechanisms, be it tradable green certificates as in the UK or feed-in tariffs as in France. For the wind offshore investment alternative considered, we assume that the power generated can be sold at feed-in tariffs (p_t^f) over the applicable period: EUR 130/MWh for the first ten years and EUR 64/MWh for the remaining 10 years reflecting the current French feed-in tariffs.

Stochastic processes retained for power We suggest modelling baseload and peakload power prices as mean-reverting processes with a linear trend just like we did for carbon. The modelling remains the same - only the fitting of parameters changes. Moving directly to the risk-neutral world:

$$\begin{cases} ln(\hat{p}_t^p) & = h_t^{p*} + \hat{X}_t^p \quad \text{(for peakload power spot price)} \\ h_t^{p*} & = \alpha^p + \beta^p.t \quad \text{(linear deterministic trend)} \\ d\hat{X}_t^p & = \theta^p.(-\lambda^p.\frac{\sigma^p}{\theta^p} - \hat{X}_t^p).dt + \sigma^p d\hat{W}_t^p \end{cases}$$

$$\begin{cases} ln(\hat{p}_t^b) & = h_t^{b*} + \hat{X}_t^b \quad \text{(for baseload power spot price)} \\ h_t^{b*}* & = \alpha^b + \beta^b.t \quad \text{(linear deterministic trend)} \\ d\hat{X}_t^b & = \theta^b.(-\lambda^b.\frac{\sigma^b}{\theta^b} - \hat{X}_t^b).dt + \sigma^b d\hat{W}_t^b \end{cases}$$

where:

- θ^p and θ^b are the constant mean-reversion speeds for the log of peakload and baseload electricity prices;
- $h_t^{p*} = \alpha^p + \beta^p.t$ is the linear trend for the log of the price of peakload power;
- $h_t^{b*} = \alpha^b + \beta^b.t$ is the linear trend for the log of the price of baseload power;
- σ^p and σ^b representing the constant volatility of the instantaneous log-price variation for peakload and baseload electricity prices;

- λ^p and λ^b are the market prices of risk for the log of the peakload and baseload power prices;

- W_t^p and W_t^b are standard Brownian motions for the log of the peakload and baseload power prices.

Calibration of the stochastic process We fit those price processes the same way we did for carbon prices (we use historical data and will perform sensitivity tests to better match price projections). We used almost five years of French baseload and peakload 2011 calendar futures from EEX/Powernext (in order to be as close as possible from the maturity date of carbon futures, i.e. December 2010). Figure 3.7 illustrates the price of power (baseload and peakload) over the sampling period. Baseload prices

Figure 3.7: French baseload and peakload power futures prices 2011 (EEX) - in EUR/MWh

data set (1,262 observations) covers from August 26th, 2005 to August 23rd, 2010 and peakload prices data set (1,259 observations) covers from August 31st, 2005 to August 23rd, 2010. The same procedure as for carbon is employed to determine the parameters' value (maximum likelihood) and the results are compiled in table 3.13. Apart from β^b, which was initially too high (0.0153) and would have implied that the price of baseload power would become higher than the price of peakload power fifty years from now (β^p initially equal to 0.0081), we used results from the econometric calibration. For the growth factors, we used a smaller one (0.0060) for both baseload and peakload price that would preserve the economic relationship between

Table 3.13: Parameters for the power price processes

α^p	Average level peakload	4.3745
$\beta^p - \lambda^p$	Linear growth peakload	0.0060
θ^p	Mean reversion force peakload	0.9125
$(\sigma^p)^2$	Instantaneous variance peakload	0.0321
α^b	Average level baseload	4.0019
$\beta^b - \lambda^b$	Linear growth baseload	0.0060
θ^b	Mean reversion force baseload	0.8921
$(\sigma^b)^2$	Instantaneous variance baseload	0.0295

baseload and peakload prices. Target prices by 2030 become EUR 62/MWh baseload and EUR 90/MWh peakload. This is in line with market analysts' projections (as of December 2010, Morgan Stanley's base case long-term electricity price for France is EUR 65/MWh).

(3) Correlation among stochastic prices processes

We also ensured that single price process generation would not deviate from the basic relationship among them. We used constant correlation factors among the increments of the three Brownian motions involved ($\rho_{p,c}$, $\rho_{b,c}$ and $\rho_{p,b}$).

Further, it should be acknowledged that the introduction of the EU ETS has hardly been neutral on the electricity prices. There has been reports of power sector incumbents' windfall profits by selling grandfathered allowances allocated for free at market prices[14]. We thus need to account for the linkages among the price processes. In the literature, two approaches have been suggested.

On the one hand, some authors explicitly modelled the level of passthrough (see Laurikka and Koljonen, 2006 [86]). Consequently, the estimated price of baseload electricity is the simulated baseload price in the absence of an emissions trading scheme (a counter-factual or business-as-usual - BAU - price in other words) to which is added the price of carbon times an estimated transformation factor. That approach has the advantage to account for the potentially directional relationship from carbon prices to electricity prices while having the disadvantage to require the modelling of a forward-looking BAU electricity price. Laurikka and Koljonen (2006) [86] estimate that transformation factor between 0.22 and 0.77 depending upon the prevailing BAU electricity price. Yet, this approach has the inconvenient to require modelling what would be a BAU power price and add modelling complexity.

[14]For instance, refer to the BundesKartellamt decisions in Germany on RWE & E.ON alleged passthrough as early as 2005.

On the other hand, carbon and power stochastic prices can be positively correlated to account for the relationship between those prices. Szolgayva et al. (2008) [91] and Fuss et al. (2008) [90] explicitly allow for some passthrough via a positive correlation factor between the noises of the electricity and the carbon price processes. The increments of the Wiener processes of electricity and carbon are assumed to be correlated at +0.7. They assert that the positive value is implying that disturbances in the carbon price are positively reflected in those of electricity. In Laurikka and Koljonen (2006) [86], the price of carbon allowance is modelled jointly with the price of baseload electricity using a quadrinomial tree. The relationship between the two prices is summarized in a correlation factor which can take the value of either 0 or 0.5. A causality study of carbon, electricity, coal, gas and stock prices (Keppler and Mansanet-Bataller, 2009 [109]) identifies that the Granger causality relationship between carbon and electricity prices evolves from phase I to phase II. This supports the idea that simulation of power and carbon prices need to be more refined than a constant correlation factor[15].

We estimated correlations between the spot price of baseload electricity, peakload electricity and carbon ($\rho_{p,c}$, $\rho_{b,c}$ and $\rho_{p,b}$) using time series employed for fitting the price processes over a common sample period of almost five years (see table 3.14 for the estimated correlations).

Table 3.14: Correlation among stochastic price processes

$\rho_{x,y}$	dW^c	dW^p	dW^b
dW^c	1.0000	0.5301	0.5561
dW^p	0.5301	1.0000	0.9837
dW^b	0.5561	0.9837	1.0000

(4) Capital expenditure budget

In order to account for a widespread soft rationing practice among European utilities, we explicitly added a variable for the capital expenditure budget. The budget is modelled as a discrete state (i.e. finite number of value taken) variable. It basically acts as a way to ensure respect of the budget constraint. Let b_t denote the budget available to invest in period t. We begin the problem with an initial endowment of $\bar{b}$. As we progress through investment nodes, b_t can take any possible combination of investment costs between $\bar{b}$ (untapped budget) and the combination that exhaust the most the budget granted.

[15] We leave this point to further research.

The next period budget corresponds to this period's budget minus investments undertaken during this period:

$$b_{t+1} = b_t - x_t$$

Looking at recent investment programs announced by European utilities and given power plant investment costs assumptions further detailed, we set the initial endowment $\bar{b}$ at EUR 5.0 billion over the investment window. With the investment alternatives investment costs and initial budget specified, we identify τ possible investment combinations.

3.2.3 Other specifications

The price of fossil fuels

In order to simplify the model used and strictly focus on carbon price uncertainty, we assume that fuel prices follow deterministic paths (that is, we know for sure the future prices of fuels).

Coal and natural gas are modelled as deterministic state variables consistent with the IEA 2008 price scenario assumptions (IEA, 2008 [110]). The IEA price scenario assumptions are the results of a top-down assessment of prior needs to encourage sufficient investment in supply and meet projected demand by 2030.

In particular, it was initially assumed that the price of coal remains at USD 120/ton[16] of coal between 2010 and 2015 and linearly goes down to USD 110/ton of coal as new mining and transportation capacity becomes available and that coal prices would remain at that level for the rest of our study horizon. Instead, in order to reflect a trend towards cheaper coal prices, we opted for a EUR 40/ton assumption for the price of coal.

Similarly, the price of natural gas in Europe is expected to follow the following path in USD/MMBTU: 11.15 in 2010, 11.50 in 2015, 12.71 in 2020, 13.45 in 2025 and 14.19 in 2030. A linear interpolation between target prices and current prices is generated for the missing dates. Beyond 2030, we apply an annual growth rate of 1.077% reflecting the average growth rate between the last two target dates. Regarding uranium, we used a per MWh cost assumption instead of a dedicated price modelling given that (1) nuclear power plants either are supplemented with long-term uranium procurement contracts or the turnkey agreements incorporate such long-term contracts to begin with and (2) the volatility of nuclear ore prices and power plant val-

[16] We assume that 1.3705 EUR/USD consistent with the average FX rate in 2007 (WEO assumptions are expressed in 2007 USD) according to the ECB.

uation sensitivity to them is quite low. In particular, we assumed a nuclear fuel cost of EUR 6.38/MWh.

Time and discount rate

We assume an investment window of 10 years starting from now (t=0). The frequency of decision points in time is annual ($t \in \|0; 10\|$). Given that power plant lifetime goes up to 60 years and building time can go up to 7 years, the horizon for simulations reaches 78 years.

The investment window retained and frequency makes our model a string of Bermudan call options with look-back features (tracked by the remaining budget) given that exercise is limited to certain dates within the life of the option and that the exercise does not necessarily kill the ability to subsequently invest in other power plants (budget permitting). The risk-free discount rate used, r, is set at 6%.

3.2.4 Choice variable

There is a single discrete choice variable, namely the decision to invest in power plants. At any decision node in time, we may invest or wait one more period (for instance to see how the carbon price evolves). Should we decide to invest, we could invest in one power plant or a "basket" of power plants.

Power plant investment alternatives

The investment alternatives considered in the model are building a CCGT power plant (incur I^G), a supercritical pulverized coal power plant without CCS (incur I^K), with CCS (incur I^C), a nuclear power plant (incur I^N), an offshore wind power plant (incur I^W) or any allowed combination of those. Once the initial investment cost has been incurred, we are entitled cash flows over the lifetime of the power plant.

The five generation technologies have the following features:

- CCGT (combined cycle gas turbine) power plants are basically characterized by a moderate capital cost, but high and volatile fuel procurement cost and an average carbon compliance cost;

- Supercritical pulverized coal plants characterized by a higher capital cost than CCGT plants, lower fuel procurement cost but higher carbon compliance cost than CCGT's. These power plants can be further retrofitted with CCS modules. We consider two type of pulverized coal-fired plant: one without CCS and another one with CCS;

- Nuclear power plants characterized by a very high capital cost but a low fuel procurement cost and no carbon compliance cost;

- An offshore[17] wind park characterized by a high capital cost (relative to capacity) but no fuel procurement cost and no carbon compliance cost. Additionally, we assume that investment in these technologies is favoured since they benefit from feed-in tariffs.

For each of those power plants, we report key cost and technical data. Power plant characteristics, including capital cost, estimates are taken from the IEA, NEA and OECD studies of projected costs of generating electricity (2010 [111] and 2005 editions [112]) for European countries. Figure 3.8 il-

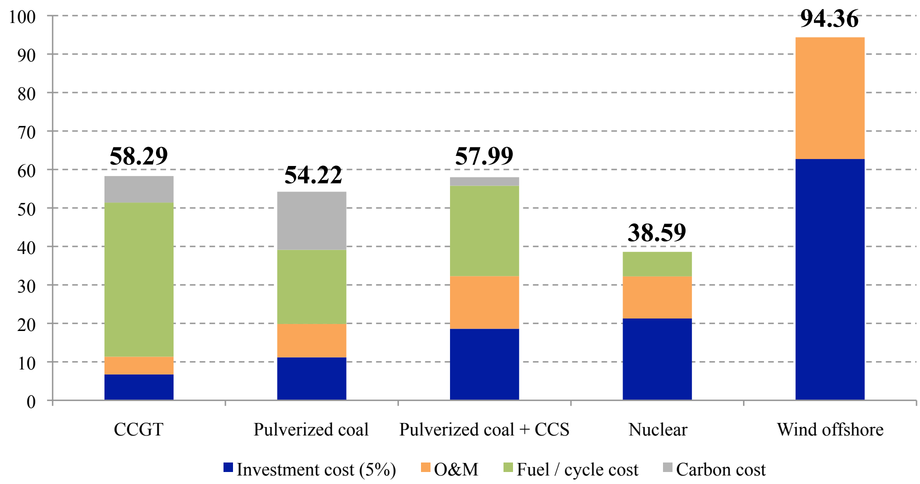

Figure 3.8: Levelised costs of electricity in EUR/MWh

lustrates the levelised costs of electricity (LCOE) for the five generation technologies considered in the model (based on IEA, NEA and OECD, 2010 [111]). The most expensive technology is the wind offshore park (hence the feed-in tariffs), while the cheapest on a per MWh basis is nuclear. The technology most exposed to investment cost is the wind offshore park, CCGTs are most exposed to fuel prices and the pulverized coal plants are most exposed to carbon prices. Once commissioned, power plants are dispatched according to the French power generation park merit order.

The CCGT plant total investment cost[18] amounts to EUR 618 million. The

[17]For the sake of comparison among generation technologies in terms of generation capacity.

[18]Initial investment cost and operation and maintenance cost over the life of the plant discounted at 8.5% following IEA, NEA and OECD, 2005 [112].

plant takes 3 years to be built and will operate during 30 years. The thermal capacity of the power plant is set at 800 MW and its thermal efficiency is set at 60%. It is assumed that the plant will deliver power 35% of the year (3,066 hours). Based on this availability factor, the expected daily output for the power plant is 6,720 MWh (2.453 GWh per annum). Regarding carbon emissions, the emissions factor of the CCGT plant is assumed at 0.353 tCO2/MWh (which amounts to 866 MtCO2 on an annual basis).

The pulverized coal plant represents a typical investment in a supercritical coal-fired plant. The pulverized coal unit total investment cost amounts to circa EUR 1,166 million without CCS and EUR 1,789 million with CCS. In both cases, the lifetime of the plant is set at 40 years and it takes 4 years to build the plant. The thermal capacity of the plant without CCS is set at 800 MW and 740 MW with CCS. Retrofitting a plant with a CCS module typically entails reducing its thermal efficiency. Therefore, the thermal efficiency of the plant with CCS is set at 38% instead of 46% without CCS. In both cases, we assume an availability factor of 30% (the plant would operate in "semi-base" in France), which represents 5.760 MWh on a daily basis (2.102 GWh p.a.) without CCS and 5.328 MWh on a daily basis (1.945 GWh p.a.) with CCS. The emissions factor without CCS is higher than for the CCGT plant and reaches 0.728 tCO2/MWh (equivalent to 1.530 MtCO2 each year). We assume that the CCS module captures 90% of the emissions of the plant without CCS. Therefore, the emissions factor with CCS is higher than for the CCGT plant and reaches 0.073 tCO2/MWh (equivalent to 142 MtCO2 each year).

The nuclear power plant is the first of the two carbon-free investment alternatives. The total investment cost (including discounted nuclear waste decommissioning) amounts to EUR 4,998 million. The plant takes 7 years to be built and will operate during 60 years. The thermal capacity of the plant is 1,630 MW. With an availability factor of 80%, this represents 31.296 MWh on a daily basis (12.14 GWh p.a.).

The offshore wind plant is the other carbon-free investment alternative. The total investment cost reaches EUR 1,022 million. The wind farm takes 1 year to be built and will operate over 25 years. The average load factor of the wind farm is 40%[19] and the capacity is 300 MW. This amounts to a potential 2.880 MWh on a daily basis (1.051 GWh p.a.).

Table 3.15 summarizes our assumptions for the power plant investment al-

[19] Higher average load factor have been reached in Denmark: Vattenfall's Horns Rev average load factor is 43% and DONG Energy's Horns Rev 2 boasts an average load factor of 46.7%.

ternatives.

Table 3.15: Power plant assumptions

	CCGT	PC	PC+CCS	Nuclear	Wind
Construction length - in years	3	4	4	7	1
Lifetime - in years	30	40	40	60	25
Thermal capacity - in MWe	800	800	740	1630	300
(Thermal) efficiency - in %	60	46	38	-	-
Average load factor - in %	35	30	30	80	40
Expected annual output - in GWh	2.453	2.102	1.945	12.14	1.051
Emissions factor - in tCO2/MWh	0.353	0.728	0.073	0.000	0.000
Lifetime emissions - in MtCO2	25.980	61.222	5.663	0.000	0.000
Investment costs - in EUR million	628	1,166	1,789	4,998	1,022

Allowable investment combinations under budget constraint

Given an initial budget of EUR 5.0 billion, this implies that the budget variable can take any of the following values:

$$b_t \in \{ \underbrace{2}_{\text{After nuclear x1}} ; ...; \underbrace{5000}_{\text{Untapped}} \}, \forall t$$

and the control variable:

$$x_t \in \{ \underbrace{0}_{\text{Wait}} ; \underbrace{628}_{\text{CCGT x1}} ; \underbrace{1022}_{\text{Wind x1}} ; ...; \underbrace{4998}_{\text{Nuclear x1}} \}, \forall t$$

3.2.5 Solving the model

The reward function

The reward function f_t identifies immediate reward from undertaking a specific choice at time t. This reward corresponds to the net present value (NPV) of given investment combination alternatives. Note that the value taken by this function depends on market prices conditions, the timing of investment, the budget level and the investment combinations decided upon.

We identified τ unique combinations of generation technologies[20].

$$f_t(b_t, x_t, S_t) = \begin{cases} 0 & \text{for } x_t = 0, \\ NPV_t^G & \text{for } x_t = I^G, \\ NPV_t^W & \text{for } x_t = I^W, \\ NPV_t^C & \text{for } x_t = I^C, \\ NPV_t^K & \text{for } x_t = I^K, \\ 2.NPV_t^G & \text{for } x_t = 2.I^G, \\ ..., & \\ NPV_t^N & \text{for } x_t = I^N. \end{cases}$$

$$s.t. \;\; x_t \leq b_t \;, \forall t$$

Where the NPV for a given technology at time t is the sum of discounted annual cash flow minus investment cost:

$$NPV_t^{tech} \quad = \sum_{j=t+build^{tech}}^{t+build^{tech}+life^{tech}} [\Pi_j^{tech}.e^{-r.j}] - I^{tech}$$

In which:

- $\Pi_t^G = 365.q^G.(\hat{p}_t^p - p_t^g/TE^G - \hat{p}_t^c.EF^G - O\&M^G)$ annual cash flow for the CCGT plant;
- $\Pi_t^W = 365.q^W.(p_t^f - O\&M^W)$ annual cash flow for the wind power plant benefiting from feed-in tariffs (first 20 years);
- $\Pi_t^W = 365.q^W.(\hat{p}_t^b - O\&M^W)$ annual cash flow for the wind power plant after having benefited from feed-in tariffs (next 5 years);
- $\Pi_t^C = 365.q^C.(\hat{p}_t^p - p_t^k/TE^C - \hat{p}_t^c.EF^C - O\&M^C)$ annual cash flow for the pulverized coal plant with CCS;
- $\Pi_t^K = 365.q^K.(\hat{p}_t^p - p_t^k/TE^K - \hat{p}_t^c.EF^K - O\&M^K)$ annual cash flow for the pulverized coal plant without CCS;
- $\Pi_t^N = 365.q^N.(\hat{p}_t^b - 6.38 - O\&M^N)$ annual cash flow for the nuclear plant;

And:

- q^G, q^W, q^C, q^K, and q^N are the daily quantities of electricity (in MWh) produced by the CCGT, wind, pulverized coal with and without CCS and nuclear plant respectively;

[20] In case the condition $x_t \leq b_t$ is not respected, we will assume, for computational purpose, that $f_t(b_t, x_t, S_t)$ takes the value of $-\infty$.

- $\hat{p}_t^c$, $\hat{p}_t^p$, and $\hat{p}_t^b$ are annual averages of monthly prices for carbon, peakload power and baseload power respectively;

- p_j^g, p_j^k and p_j^f are the average annual prices for natural gas and coal and the feed-in tariff for offshore wind;

- TE^C, TE^K and TE^G are the thermal efficiencies of the pulverized coal with and without CCS and CCGT plants respectively;

- EF^C, EF^K and EF^G are the carbon emissions factors (in tCO2/MWh) of the pulverized coal with and without CCS and CCGT plant respectively;

- $O\&M^G$, $O\&M^W$, $O\&M^C$, $O\&M^K$ and $O\&M^N$ are the operation and maintenance cost per MWh for the CCGT, wind, pulverized coal with and without CCS and nuclear plant respectively. O&M over lifetime are discounted back to investment time and to simplify calculations. The data source remains the IEA, NEA and OECD study;

- r corresponds to the zero-coupon rate (the risk-free rate);

- t corresponds to passage of time, expressed in years;

- $life^G$, $life^W$, $life^C$, $life^K$ and $life^N$ are the lifetimes of the CCGT, wind, pulverized coal with and without CCS and nuclear plant respectively;

- $build^G$, $build^W$, $build^C$, $build^K$ and $build^N$ are the construction times of CCGT, wind, pulverized coal with and without CCS and nuclear plant respectively;

- I^{tech} is the investment cost incurred for each of the various power generation technologies;

The Bellman value function

The principle of optimality applied to our discrete time mixed states decision models yield Bellman's recursive functional equation. Here, V_t denotes the maximum attainable sum of current and expected future rewards given that the processes are in states b_t and S_t in period t. For all b_t and for all S_t:

$$V_t(b_t, S_t) = \max_{x_t} \left\{ \underbrace{f_t(b_t, x_t, S_t)}_{\text{immediate reward}} + \underbrace{e^{-r}.\mathbb{E}_t^Q[V_{t+1}(b_t - x_t, \tilde{S}_{t+1})]}_{\text{discounted expected reward}} \right\}$$

The first element of the Bellman equation corresponds to the immediate reward component (f) while the second element corresponds to the discounted expected future benefits (knowing S_t). This latter component is also known, in the financial option terminology, as the continuation value and will be later estimated by OLS following the method suggested by Longstaff and Schwartz (2001, [2]).

The post terminal value function is the special case at the end of the investment window. Since we are in a finite horizon problem, the investor cannot invest after T periods but may earn a final reward V_{T+1} which corresponds to the remaining immediate investment opportunity of the possible investment "baskets". We assume no continuation value after T. At expiration, for all b_T and for all S_T:

$$V_T(b_T, S_T) = \max_{x_T} \left\{ \underbrace{f_T(b_T, x_T, S_T)}_{\text{immediate reward}} \right\}$$

In our backward recursion setting, this last decision node will be our starting point. With V_T, we can find recursively V_{T-1} for all states (b_T, S_T). With V_{T-1}, we can find recursively V_{T-2} for all states (b_{T-1}, S_{T-1}) and so on until $V_0(\bar{b}, S_0)$ is derived and the optimal policy established since there is no immediate uncertainty at t=0 so that we can work our way forward into the recursion.

Algorithm for the model

The model is solved using the least-squares Monte Carlo approach (Longstaff and Schwartz, 2001 [2] and Gamba, 2003 [3]) in order to account for various sources of uncertainty and flexibility in timing and technology (see appendix section for implementation in the Matlab environment). Compared to the existing literature, we adapt the method to explicitly allow for capital rationing and choose among various technologies rather than just determining an optimal option exercise time.

The annex section of this thesis features a step-by-step introduction to the methodology employed. In this section, we directly jump to the general case. We begin by describing the general procedure employed and then present the results of the initial calibration. Figure 3.9 describes our general procedure to determine optimal decisions in our real options framework.

We now look in details at each of the steps involved.

Step 1 - Simultaneously generate Γ risk-neutral paths for the stochastic state variables
We are generating jointly (since the price processes are correlated) Γ sample paths for the three price processes considered (carbon $\hat{p}_t^{c,i}$, baseload power

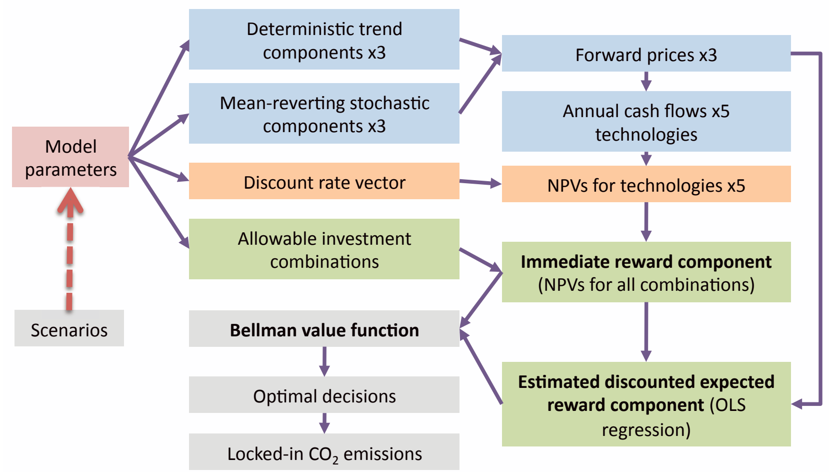

Figure 3.9: Steps to solve the LSM model

$\hat{p}_t^{b,i}$ and peakload power $\hat{p}_t^{p,i}$, with $i \in \|1;\Gamma\|$) according to the calibration retained over the necessary horizon (longest investment decision node + longest construction time + longest lifetime), i.e. over "12 x 78" months. We obtain an "Γ x (12 x 78) x 3" matrix with the price paths. Note that Γ is typically a large number (10,000).

As a general check, we generate plots of a sub-sample of price paths (ten of them) for the three stochastic state variables (see Figure 3.10 for carbon and Figure 3.11 for peakload and baseload power).

Step 2 - Calculate Γ NPV paths for the five technologies
Based on the Γ sample price paths generated, we compute the net present values for the five different technologies (nuclear $NPV_t^{N,i}$, pulverized coal without CCS $NPV_t^{K,i}$, with CCS $NPV_t^{C,i}$, wind offshore $NPV_t^{W,i}$ and CCGT, $NPV_t^{G,i}$) every year from now to ten years from now (11 investment decision nodes). With those NPVs, we are able to value any of the τ investment combinations that can be undertaken at any time $t \in \|0;10\|$ (budget permitting). We obtain an "Γ x 11 x 5" matrix with the NPVs for the five technologies considered.

Again as a general check, we generate a distribution plot of the NPVs of the different technologies at t=0, t=5 and t=10 (see Figure 3.12).

Step 3 - Determining the allowed investment combinations
Given the initial budget constraint $\bar{b}$ and investment costs I^N, I^K, I^C, I^W and I^G and denoting Q^{tech} the quantity of a given technology we invest in

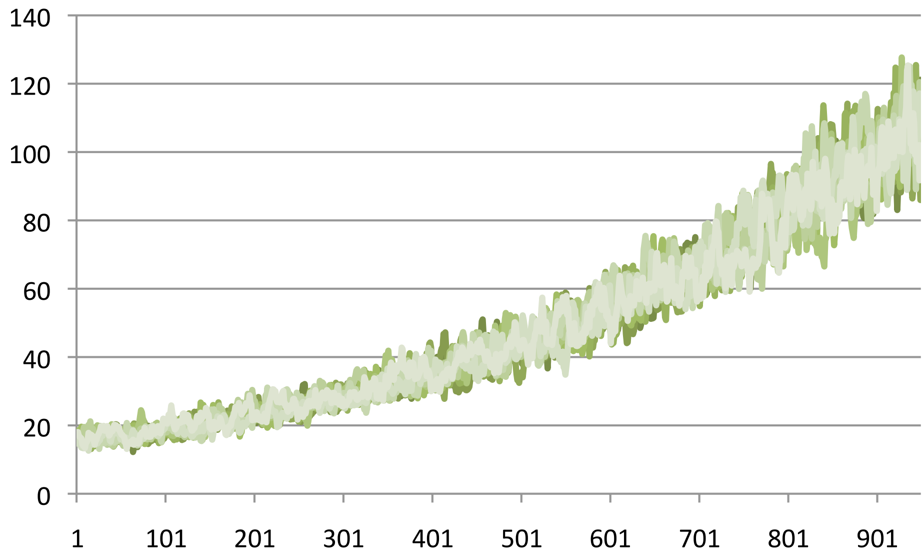

Figure 3.10: Ten sample carbon prices - in EUR/tCO2

(Q^{tech} being an integer - no investment in half a plant for instance), we recognize that at any time, the following relation must be satisfied:

$$x_t = I^N.Q^N + I^K.Q^K + I^I.Q^C + I^W.Q^W + I^G.Q^G \leq b_t \ , \forall t.$$

We identify that the control variable can take one of the following τ values:

$$\begin{aligned} x_t &\in \{\ 0;\ I^G;\ I^W;\ ...;\ I^N\} \\ &\in \{\ 0;\ 628;\ 1022;\ ...;\ 4998\} \end{aligned}$$

And the budget can therefore take one of the following τ values:

$$\begin{aligned} b_t &\in \{\ \bar{b} - I^N;\ ...;\ \bar{b} - I^W;\ \bar{b} - I^G;\ \bar{b}\} \\ &\in \{\ 2;\ ...;\ 3978;\ 4372;\ 5000\} \end{aligned}$$

Step 4 - Start from the last decision node at t=10

We start from t=10, the last time we are able to invest during the investment window. At this last decision node, the continuation value is assumed to be zero. That is to say - once the investment opportunity is missed, there is no ability to generate cash flows from it. The value function takes the following form in which S_{10}^i is a set of stochastic state variables at t=10 and on path i:

$$V_{10}(b_{10}, S_{10}^i) = \max_{x_{10}} \left\{ f_{10}(b_{10}, x_{10}, S_{10}^i) \right\} \ , \forall i.$$

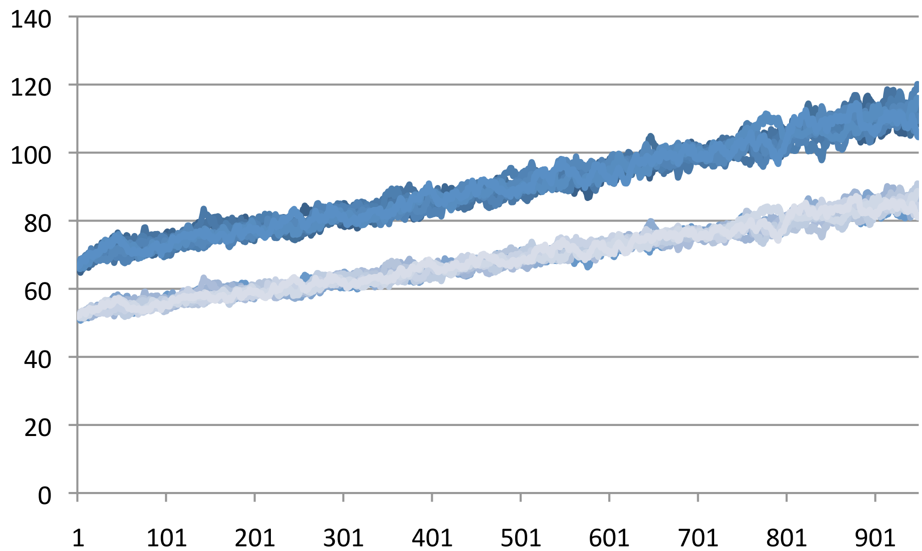

Figure 3.11: Ten sample peakload and baseload power prices - in EUR/MWh

For all the possible budget levels at b_{10} (τ) and on all the Γ paths, we compute $V_{10}(b_{10}, S^i_{10})$. We obtain τ "Γ paths x τ possible decisions" tables in which we identify the immediate reward components $f_{10}(b_{10}, x_{10}, S^i_{10})$. These are stored in the matrix $\mathcal{M}R_{10}$ (the matrix storing the reward functions). Based on those tables, we determine the maximum value among $f_{10}(b_{10}, x_{10}, S^i_{10})$ and associated investment decision for a given remaining budget level and for a given path. These are consigned in two "Γ paths x τ budget levels" matrices, one for the maximum value ($\mathcal{M}V_{10}$) and one for the corresponding optimal decision ($\mathcal{M}x^*_{10}$).

Note that the condition, $x_{10} \leq b_{10}$, must be satisfied. Therefore, the calculations are eased when the remaining budget actually limits the possible investment combinations (for instance when the budget does not allow any additional investment, the only suitable course of action is to wait).

We end up this step with the matrices $\mathcal{M}R_{10}$, $\mathcal{M}V_{10}$ and $\mathcal{M}x^*_{10}$ (check the structures of matrices $\mathcal{M}R_t$, $\mathcal{M}V_t$ and $\mathcal{M}x^*_t$ in the annex for more details) in hands.

Step 5 - Moving backward in the decision-making process (from t=9 to t=1)

The value function now incorporates a continuation value and takes the

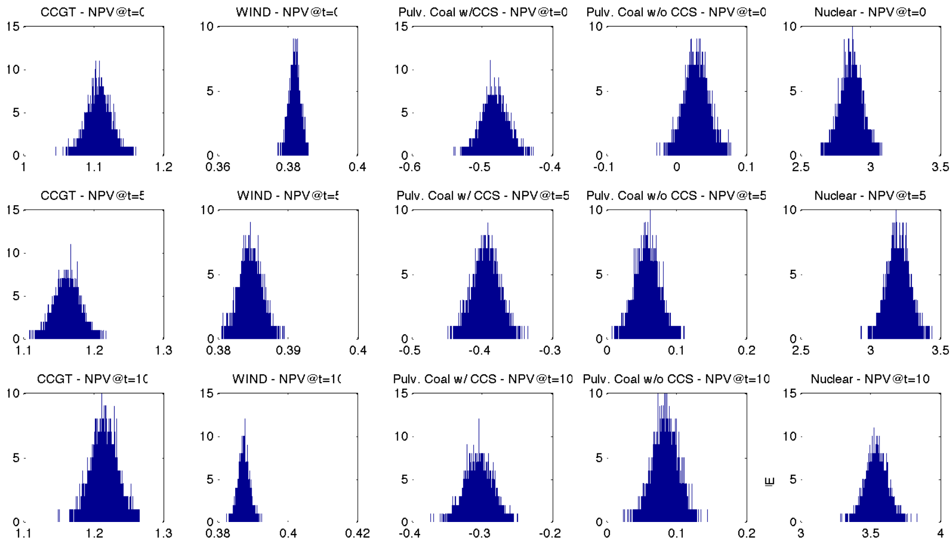

Figure 3.12: Sample NPV distributions - in EUR million

following form:

$$V_9(b_9, S_9^i) = \max_{x_9} \left\{ f_9(b_9, x_9, S_9^i) + e^{-r}.\mathbb{E}_9^Q[V_{10}(b_9 - x_9, \tilde{S}_{10}^i)] \right\} \ , \forall i \text{ and } \forall ti.$$

In order to determine the value maximizing choice for all the remaining budget level (b_9) and each sample path, we have to:

- compute $f_9(b_9, x_9, S_9^i)$, $\forall i$ and $\forall b_9$ like we did in step 4 and store the resulting τ "Γ paths x τ possible decisions" reward functions in matrix $\mathcal{M}R_9$;
- estimate $e^{-r}.\mathbb{E}_9^Q[V_{10}(b_9 - x_9, \tilde{S}_{10}^i)]$ $\forall i$ and $\forall b_9$ using OLS regressions like we did in the preliminary stochastic case study (else that would be clairvoyance and we would be replacing a stochastic problem by a deterministic one) and store the resulting τ "Γ paths x τ possible decisions" estimated continuation value functions in matrix $\mathcal{M}C_9$;

In particular, we consider the following OLS regression model:

$$\begin{aligned} e^{-r}.\mathbb{E}_t^Q[V_{t+1}(b_t - x_t, \tilde{S}_{t+1}^i)] &\approx \phi_{t+1}(b_t - x_t, S_{t+1}^i) \\ &= c_{0,t}^{b_t - x_t} + c_{1,t}^{b_t - x_t}.\hat{p}_t^{c,i} + c_{2,t}^{b_t - x_t}.\hat{p}_t^{p,i} \\ &\quad + c_{3,t}^{b_t - x_t}.\hat{p}_t^{b,i} + e_i^{b_t - x_t} \end{aligned}$$

We regress discounted continuation values (contingent on the decision taken at t) to be found in $\mathcal{M}V_{10}$ against a set of contemporary carbon, peakload and baseload prices. It should be stressed that, contrary to the preliminary stochastic case study, we do not have to estimate a single continuation value but rather up to τ. Once estimated, we store $\phi_{10}(b_9 - x_9, S^i_{10})$ in matrix $\mathcal{M}C_9$ (check $\mathcal{M}C_t$ in the annex for more details).

Finally, we have to:

- combine matrices $\mathcal{M}R_9$ and $\mathcal{M}C_9$ to determine $V_9(b_9, S^i_9)$, $\forall i$ and $\forall b_9$. This entails adding the $\mathcal{M}R_9$ and $\mathcal{M}C_9$ matrices and keep the maximum combined value , $\forall i$ and $\forall b_9$;
- store the resulting maximum combined value, i.e. $V_9(b_9, S^i_9)$, in $\mathcal{M}V_9$ and related optimal decisions in $\mathcal{M}x^*_9$;
- repeat the process for $t = 8$ until $t = 1$.

Step 6 - The first decision node (t=0)
At $t = 0$, the budget variable uncertainty is resolved, we know for sure that b_0=$\bar{b}$. The value function hence takes the following form:

$$V_0(\bar{b}, S^i_0) = \max_{x_0} \left\{ f_0(\bar{b}, x_0, S^i_0) + e^{-r}.\mathbb{E}^Q_0[V_1(\bar{b} - x_0, \tilde{S}^i_1)] \right\} \ ,\forall i.$$

In order to determine the value maximizing choice for each sample paths, we do the followings:

- We compute $f_0(\bar{b}, x_0, S^i_0)$ $\forall i$ and store the resulting "Γ paths x τ possible decisions" reward functions in matrix $\mathcal{M}R_0$. Note that this matrix is smaller to the other $\mathcal{M}R_t$ matrices since only one budget level is possible at t=0;
- At t=0, the set of contemporary carbon, peakload and baseload prices used in the regression are known as well since they are estimated based on current prices. This means that we cannot estimate $e^{-r}.\mathbb{E}^Q_0[V_1(\bar{b} - x_0, \tilde{S}^i_1)]$ using OLS regressions like we did in step 5. Instead, following Longstaff and Schwartz (2001 [2]) and like we did in the illustrative case study, we simply discount one year back $V_1(\bar{b} - x_0)$ $\forall i$ to be found in $\mathcal{M}V_1$ in the annex. The resulting approximated continuation value is stored in $\mathcal{M}C_0$;
- We combine matrices $\mathcal{M}R_0$ and $\mathcal{M}C_0$ to determine $V_0(\bar{b}, S^i_0)$,$\forall i$. This entails adding the $\mathcal{M}R_0$ and $\mathcal{M}C_0$ matrices;
- We store the resulting value for $V_0(\bar{b}, S^i_0)$ in $\mathcal{M}V_0$ and related optimal decisions in $\mathcal{M}x^*_0$.

Step 7 - The optimal path and implied emissions
At this point, we have a set of eleven matrices $\mathcal{M}V_t$ and $\mathcal{M}x^*_t$ indicating

maximum value and optimal decisions ,$\forall t$ and $\forall i$.

We start from t=0 and compute averages over all paths in matrix $\mathcal{M}V_0$ (Γ x x_0 value function matrix at t=0, i.e. when budget is full). Here, we look for:

$$V_0(\bar{b}) \quad = \quad \max_{x_0} \left\{ \frac{1}{\Gamma} \sum_{i=1}^{\Gamma} [f_0(\bar{b}, x_0, S_0^i) + \phi_1(\bar{b} - x_0, S_1^i)] \right\}$$

The result suggests a peculiar optimal decision ($\hat{x}_0^*$) that is expected to maximize V_0 (which needs not be identical to what is to be found in $\mathcal{M}x_0^*$).

We move forward in time, and solve recursively the following equation $\forall t \in \|1; 9\|$:

$$\begin{aligned} V_t(\bar{b} - \sum_{k=0}^{t-1} \hat{x}_k^*) = \max_{x_t} \quad & \left\{ \frac{1}{\Gamma} \sum_{i=1}^{\Gamma} [f_t(\bar{b} - \sum_{k=0}^{t-1} \hat{x}_k^*, x_t, S_t^i) \right. \\ & \left. + \phi_{t+1}(\bar{b} - \sum_{k=0}^{t-1} \hat{x}_k^* - x_t, S_{t+1}^i)] \right\} \end{aligned}$$

When at t=10, we solve the following equation (no estimated discounted continuation value):

$$V_{10}(\bar{b} - \sum_{k=0}^{9} \hat{x}_k^*) \quad = \quad \max_{x_{10}} \left\{ \frac{1}{\Gamma} \sum_{i=1}^{\Gamma} [f_{10}(\bar{b} - \sum_{k=0}^{9} \hat{x}_k^*, x_{10}, S_{10}^i)] \right\}$$

We find a set comprised of optimal decisions ($\hat{x}_0^*$, $\hat{x}_1^*$, ..., $\hat{x}_{10}^*$). This set of decision is providing the decision-maker with guidance on what to do each year.

Given the optimal path, we expect a given amount of locked-in CO2 emissions. That amount can be estimated based on (1) the carbon emission factor of the technology we invest in, (2) the expected annual production and (3) the life length of the plants. [21]

3.3 Results and discussion

This section presents results from the model (base case results and sensitivity analyses) and policy insights derived from it. Although it is impossible to perfectly anticipate what climate polices will be over the lifetime of a newly-constructed power plant, EU ETS current and expected policy designs provide insights into what will affect power plant relative profitability.

[21] Changes over the lifetime of the investment (policies, technologies, etc.) and impacts on these parameters is beyond the scope of our analysis.

Of course, in no way would price be "micro-managed" still, prices can be supported by means of support policies to make sure that the climate policy objective remains intact. Figure 3.13 describes our general procedure to analyse results from our real options framework.

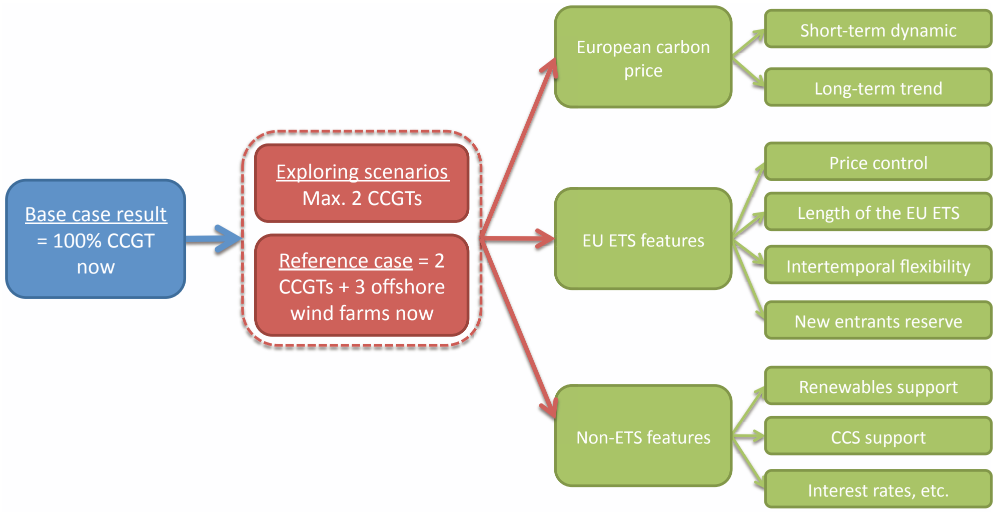

Figure 3.13: Testing scenarios - sensitivity tests

The model's base case indicates that the optimal decision is to invest in seven CCGT plants now (blue box on Figure 3.13) which potentially locks in 156 million tons of carbon over their lifetime. Several sensitivity tests indicate a lack of diversification in optimal decisions be it on the timing of investment decisions or in technology choices.

Given that our research question is not on comparing various generation technologies but rather on developing scenarios around investment portfolios (how is the EU ETS changing investment choices and timing?), we set the maximum number of investments in a given technology (maximum 2 CCGT plants). This increases the granularity of results and enables us to capture real option effects and shifts in investment choices in a portfolio context. Sensitivity tests become more insightful and allow us to identify technology and timing trigger points caused by changes in policy. Therefore, the base case becomes to invest in 2 CCGTs and 3 wind offshore parks right now (red boxes on Figure 3.13).

In the following sections, we will consider the impact of (1) policies aiming at influencing the carbon price, (2) policies aiming at modifying the EU ETS characteristics (including price control measures) and (3) climate policies outside the EU ETS, renewables and CCS support notably (green boxes on Figure 3.13).

3.3.1 Influencing the European carbon price

Now that we discussed the model's specifications, we turn to the policy questions using sensitivity tests. We begin by looking at the impact of carbon prices modelling on generation portfolio choices. In particular, we explore the impact of the short-term dynamic (volatility and mean reversion speed) and long-term trend (start level and growth factor).

Short-term dynamic

In our model, the short-term dynamic of the carbon price is comprised of two opposite forces: the volatility parameter driving the price away from its long-term trend on the one hand, and the mean-reversion speed parameter taking back the carbon price to its long-term trend on the other hand.

The mean reversion speed is typically interpreted in terms of half-life ($T_{\frac{1}{2}}$) of mean reversion, which is:

$$T_{\frac{1}{2}} = \frac{ln2}{\theta}$$

The half-life for the price of carbon here is the time it takes for the expected carbon price to reach the middle price between its current value and the long-run mean. The initial calibration of the carbon price suggests a mean reversion speed of 2.45 equivalent to a half-life of 0.2829. In other words, the carbon price tends to be pulled back to its long-term level over a period of roughly three months and a half.

The higher the mean reversion speed, the quicker the underlying process will come back to its long-term trend. Conversely, a very low mean reversion speed like 0.01 indicates that the process is indeed disconnected from an equilibrium price trend as it tends to be pulled back to its long-term level only over a period of roughly 70 years.

Recall that our base case result is 2 CCGTs and 3 wind offshore parks now. Performing a sensitivity study of the investment decisions to the mean reversion speed (i.e. holding other parameters constant including the 19% volatility), we find that the base case prevails. The only exception is when the mean reversion speed is set to less or equal to 0.01 (i.e. roughly 70 years to revert to the equilibrium price), in which case, the investor invests in the three wind offshore parks now but delays the investment in the two CCGTs up to ten years from now. Even though the width of deviation from the trend (i.e. the volatility factor) is reasonable, the extremely low mean reversion speed recognizes the possibility of adverse carbon prices over time that could erode the profitability of the CCGTs. Therefore, the investor awaits a clearer picture of carbon prices and delays its investment in CCGTs.

We also performed a sensitivity study of investment decisions to the volatility parameter (*ceteris paribus*). The initial calibration of the carbon price suggests a constant annual volatility of 19%, which is quite similar to that of other forward contracts on energy commodities. Had we used a sampling period ending six to seven months earlier, we would have obtained a constant annual volatility in the range of 40-50% (the sample included the price crash caused by the crisis).

The higher the volatility, the larger the width of price deviation from the long-term trend. Again, the base case prevails until extreme parameters levels are reached. For sustained volatility levels above 288%, the investor shuns the base case directly for a nuclear hedge. This level of volatility can only be reached in spot power market and is typically not sustained over a comparable horizon. Therefore, even though the mean reversion speed is comparable to several commodity markets, the width of potential deviations from equilibrium erodes the profitability of investment in the CCGTs. With the CCGTs unprofitable, the investor turns out to be better off with a single nuclear power plant rather than with only the three wind offshore wind parks.

Recognizing that parameters seldom stay put while others are being modified (especially within a same price process), we were able to map out a joint sensitivity study of investment decisions to both the mean reversion speed and volatility parameters. Figure 3.14 indicates the different areas of suggested investment combinations and timing. The intuition of two opposite forces is to be found in the figure. In the upper-left corner, mean reversion is high (potentially lower than two months) and volatility is non-existent (deterministic scenario for the price of carbon). The prevailing component for carbon is therefore the long-term trend and the base case scenario is realized.

At the opposite corner (lower-right), mean reversion speed is very low (potentially longer than 50 years) and volatility extreme and adverse for exposed cash flows. The carbon price is erratic and behaves almost like a random walk. The short-term component prevails over the long-term trend and alternative investment decisions are taken the closer the investor gets to this corner. In particular, the investor will move through the following regions:

- **Tolerate adverse carbon prices:** First, the investor remains quite long in the base case area (blue area) even with a volatility parameter as high as 150% and a mean reversion speed equivalent to eight

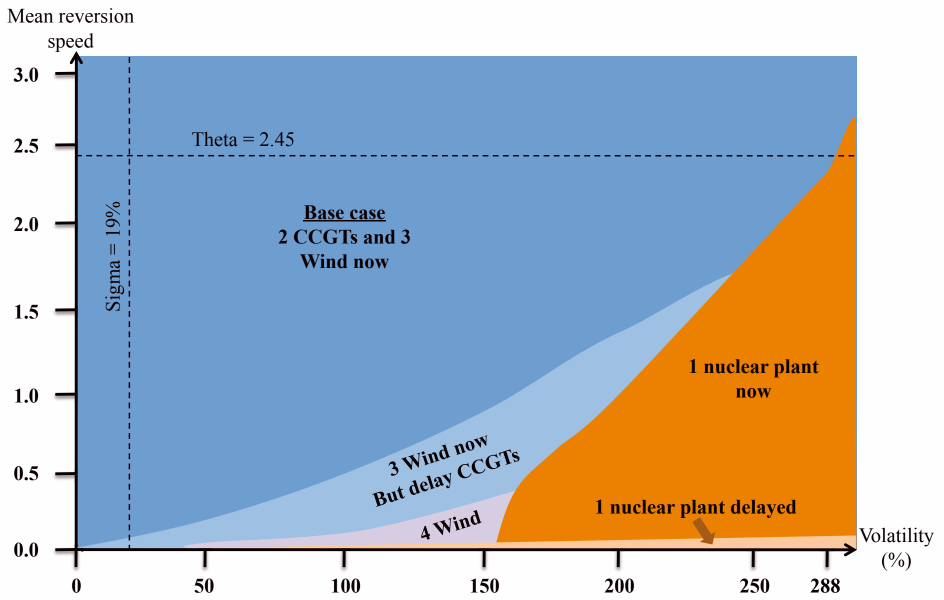

Figure 3.14: Sensitivity of investment decisions to carbon price mean reversion speed and volatility

months. In our investment framework, it appears that the investor can tolerate volatile prices, which are sustained relatively long. Of course, profitability margins of carbon-emitting generation are affected along the way but not to the extent that a change in investment decisions would be triggered.

- **Delay investment in carbon-emitting generation:** Second, in case the carbon price becomes too volatile and / or tends to revert too slowly to equilibrium[22], the investor moves to the light blue area. There, the investor will delay the investment in the two CCGTs up to ten years from now. On the upper left boundary of the light blue area, investment in the CCGTs is delayed only one to two years from now, while it is delayed ten years from now closer to the lower or right boundaries. This is a typical real options result. Still, the investor will undertake investment in the three wind offshore parks now, which are unaffected.

- **Hedge against carbon prices:** Third, when delaying investments in carbon-emitting CCGTs will not suffice (i.e. when they become unprofitable most likely), the investor will turn to carbon prices hedges. In the light pink area, the investor decides to invest in three wind

[22]For instance, with the volatility around 150% and the mean reversion speed equivalent to two years and nine months.

offshore parks now and one later (up to ten years from now). The investor hedges primarily against sustained deviations from carbon price equilibrium (and secondarily, against volatile carbon prices). In the orange area, the investor decides to invest in a nuclear power plant to hedge against extremely volatile carbon prices (and secondarily, against slowly mean reverting carbon prices).

- **Delay the hedge against carbon prices:** Finally, in the worse case (extremely slow mean reverting speeds of more than 4 years and quite volatile carbon prices), the investors moves to the light orange area. In this area, the investor hedges against carbon prices by investing in the nuclear power plant. But he does so, ten years from now, expecting that the carbon price uncertainty be resolved (there are still some chances that the investor would benefit from lower than expected carbon prices).

While, the base case investment represents approximately two-thirds of the surface in Figure 3.14, it should be noted that not all elements in the surface are as likely and the two-thirds area covers pretty much of the most likely cases. Recall that both short-term forces tend to compensate for one another so that areas closer to the lower-right corner are commensurately harder to reach.

Policy-wise, a move towards a more stable short-term framework can be achieved by (1) improving the informational efficiency of the EU ETS (ensuring a quicker return to fundamentals) and (2) helping correct the capital market inefficiencies. In no specific order, this would include limiting extreme price movements by streamlining EC communications relative to the EU ETS (in a similar fashion to the US Federal Reserve), regulating who is authorized to act as market-makers (thereby affecting market liquidity), etc. With our modelling assumptions, the direct impact would be to alter market price volatility and mean reversion speed.

Carbon long-term price trend

The long-term trend (or equilibrium) for the carbon price is modelled as an exponential linear trend with a level component (intercept), α and a growth rate component (slope), β.

The linear trend starting level, α, is initially calibrated at 2.69, which is equivalent to EUR 14.73/tCO2 (current market price at time of running simulations). At this level, the optimal investment is the base case (2 CCGTs and 3 offshore wind parks now). The level component reflects the overall constraint level (There might be some deviation from equilibrium but this should be corrected depending on the mean reversion speed), reflecting cap levels and carbon reduction pledges. The higher the linear trend starting level, the higher the reference point to which a growth rate, β, is applied. We performed sensitivity tests to the linear trend starting level, holding all else equal. We found that below EUR 5.2/ton CO2e, the investment in two CCGTs and three pulverized coal-fired plants without CCS now was favoured - the carbon constraint being not enough to prevent such investment. On the other hand, above a starting level of EUR 33.9/ton of CO2e (and still with the annual growth rate of 2.5%), the investment in CCGTs is not profitable any more and the investor turns to a single nuclear power plant now instead (which is more profitable than the three offshore wind parks).

The growth rate component is annual and constant over time. That would correspond to the annual incremental effort required by the policy. It is initially set at 2.5% per annum. At this rate, the base case combination is chosen. A sensitivity test to the growth rate component (with a starting level at EUR 14.73) reveals that:

- Above 7.5% (which would be equivalent to EUR 67/ton of CO2e in 2030), the likelihood of extreme carbon prices is such that any investment in a CCGT is forgone in favour of a single nuclear power plant now.

- Between -3.5% and -23.5% (equivalent to between EUR 7.31 and EUR 0.13 by 2030), the carbon price long-term trend becomes such that, even with feed-in tariffs, the investment in offshore wind parks cannot compete with pulverized coal plants without CCS. Therefore, the choice is to invest in two CCGTs now and three pulverized coal without CCS over time (the higher the growth rate, the later the coal investment given that there is still uncertainty at play).

- Below -23.5% (equivalent to below EUR 0.13 by 2030) and with the initial calibration for the short-term dynamic, there is no possible change in carbon prices. The investor decides to invest in two CCGTs and three coal-fired power without CCS plants right now.

Again, recognizing that both components of the long-term trend are related, we were able to map out a joint sensitivity study of investment decisions to both the level and growth parameters. Figure 3.15 indicates the different areas of suggested investment combinations and timing. The figure shows that the very existence of a carbon price has a clear impact on generation combination. Rather than two opposite forces (as in the case of the short-term dynamic), the two components of the long-term trend tend to go the same way (the higher, the more carbon-constrained).

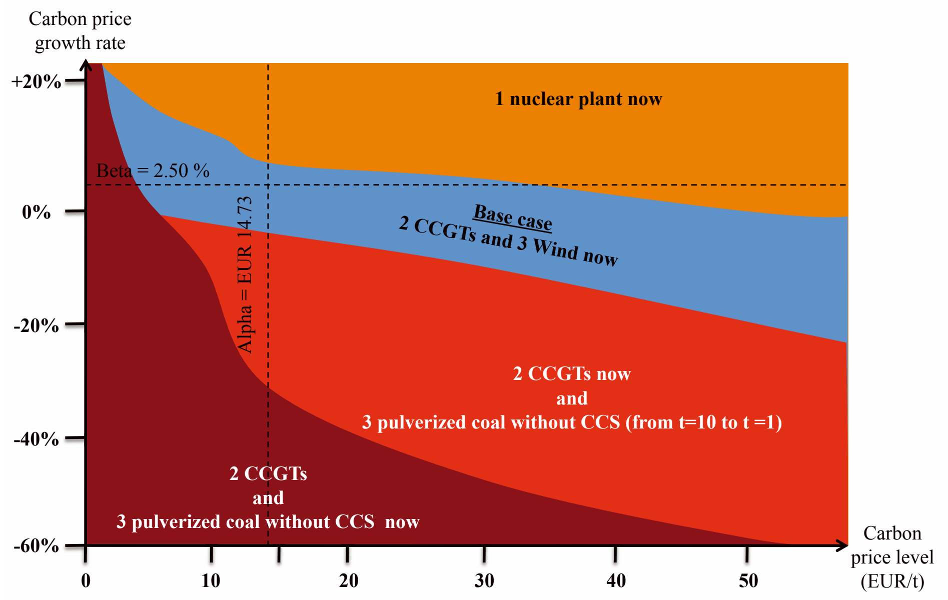

Figure 3.15: Sensitivity of investment decisions to carbon price trend level and growth rate

Still, a high level is not entirely equivalent to a high growth rate. A high level is a starting point - something that is granted. On the other hand, a high growth rate is a potential and is subject to the short-term dynamic (with more or less sustained deviations).

Coming back to Figure 3.15, we observe that in the upper-right corner, we go towards more carbon constraint and in the lower-left corner, we go towards no carbon constraint at all. We are able to identify four investment areas (from upper right to lower left):

- **Hedge against carbon prices:** Should the carbon price become too high, the investor is better off moving away from the base case area (where the CCGT has become unprofitable) to the orange area, where he will invest in a single nuclear power plant now as a hedge. Prices either needs to be low and grow quickly and sustainably or to be high enough to grow slowly[23]. We find that the carbon price trend component needs to be as low as EUR 50/ton of CO2e by 2030.

- **Tolerate adverse carbon prices:** In the base case area (blue area on the figure), the investor is exposed to changes in the carbon constraint to which investment in CCGT is sensitive. Cash flows are affected but

[23]With a start level above EUR 50/ton of CO2e, a slightly negative growth rate might even suffice (-0.8%).

not enough to trigger a shift to the surrounding areas. To remain in this area, the carbon price by 2030 needs to be in the range between EUR 10 and 50 per ton of CO2e.

- **Invest in carbon-emitting generation cautiously:** In case the EU climate policy objectives are loosened, the long-term trend component will be affected. If the cut is too high, the carbon constraint will not be enough to prevent investment in coal-fired generation. In the light red area, the investor opts to invest in two CCGTs now and, instead of three offshore wind parks now, invests in three coal-fired plants without CCS over time. The closer to the base case boundary, the later the investment in coal-based generation is performed and vice versa. The delay behaviour is explained by the fact that the long-term trend, while critical in investment decision-making, is not alone to shape the carbon price. The short-term dynamic might still reverse the situation and make coal-fired investment unprofitable, hence the wait-and-see here. In this area, typical carbon prices by 2030 range between EUR 0.10 and EUR 10 per ton of CO2e.

- **Invest in carbon-emitting generation:** In case the level is too low from the beginning (below EUR 10 in general) and / or the growth rate is highly negative (below minus 10% in general), it is highly likely that carbon prices by 2030 will be below EUR 0.01 per ton of CO2e. In that configuration, constraining carbon prices are not likely and the investor decides to invest now in two CCGTs and three pulverized coal plants without CCS.

Policy-wise, a higher carbon constraint can be achieved by making major changes to the EU ETS characteristics:

- **Opt for a less favourable allocation basis:** allowances can be allocated either on a free basis or on a paying basis (auctioning). The impact is critical in an investment decision as allowances allocated for free inherently help carbon-emitting capacity at least as long as the allocation method remains the same. Theoretically, there is no impact on carbon market prices but there is a strong impact on the profitability of investments. Over phase I and II, the allowances have been allocated mostly for free in order to ease the shift towards the EU ETS for compliance-buyers. During phase III, a phased-in auctioning is planned. In our model, though this should not change much as we considered the case of a new entrant who did not benefit from a new entrants reserve support.

- **Modify the allocation reference point:** the definition of a proper reference point, to which an effort rate is applied, is a necessary step in any allocation process. Different methods are possible. Allowances can be allocated on the basis of historical emissions at a single point in time (grandfathering), at given regular points in time (updating) or on the basis of some technological feat in a sector (benchmarking). The impact is solely on the cap and is therefore reflected in carbon prices. With a constant emissions reduction effort rate and with a downward emission trend, the later the reference point, the higher the cap (which will be reflected in the trend level). Yet, if properly anticipated well ahead by regulated entities, this might give an improper incentive to increase emissions over the reference period.

- **Increase the emissions reduction effort rate:** over phase III, it was long debated that the rate of effort may change from -20% to -30% initially depending on the outcome of Copenhagen and forthcoming COP/MOP meetings. By essence, a cap-and-trade policy features a declining cap within and between trading phases. This is the most obvious way to increase the carbon constraint on capped entities.

- **Decrease the offset acceptance for compliance:** in order to provide compliance buyers with more flexibility in achieving their emissions reduction goals, the EU ETS allows the use of offset credits (CERs and ERUs) *in lieu* of EUAs up to a certain amount. This lowers the demand for allowances all things equal, and thus depresses EUA prices. In addition to that, this influences the profitability of investments undertaken. In the current configuration, phase II compliance can be achieved by surrendering as much as 13.5% (EU average) of CERs and ERUs among carbon assets. CERs and ERUs that were not used in phase II can be transferred to phase III. According to the EC, *"between 2008 and 2020, the EU ETS legislation provides for use of credits up to 50% of the overall reductions below 2005 levels made under the EU ETS"*. Moreover, in August 2010, the EC hinted at potential qualitative screening of offsets over phase III to use for EU ETS compliance. Ultimately, this would translate into a lower quantity of cheap CERs eligible for compliance, which means, if not higher prices, at least less downward pressure. The lower the percentage of offsets accepted, the lower the downward pressure on EUA prices. In June 2011, the EC formally adopted a ban on credits from HFC-23 and N20 Kyoto projects for use in the EU ETS starting 2013.

- **Overlapping carbon tax on regulated entities:** finally, we could consider that, in addition of the EU ETS, a carbon tax levied on emissions from combustion installation is a possibility in some Member States. The level of the this tax would be factored-in in investment decision-making and probably affect optimal investment combinations and timing. Such proposals emerged notably in France and in the UK.

Short-term vs. long-term effects

It has been argued in the literature (Fuss et al. 2008 [90] and in a non-carbon framework, Näsällälä and Fleten 2005 [82])) that the short-term and long-term components of carbon price uncertainty had opposite effects on investment valuation and decisions.

Even though, we do not use exactly the same type of modelling, we will gain insights on the relationship between one of the short-term dynamic components, volatility, and one of the long-term dynamic components, growth rate.

Analysing the sensitivity of decision-making to both the short-term volatility parameter and the long-term trend growth rate, Figure 3.16 indicates the different areas of suggested investment combination and associated timing.

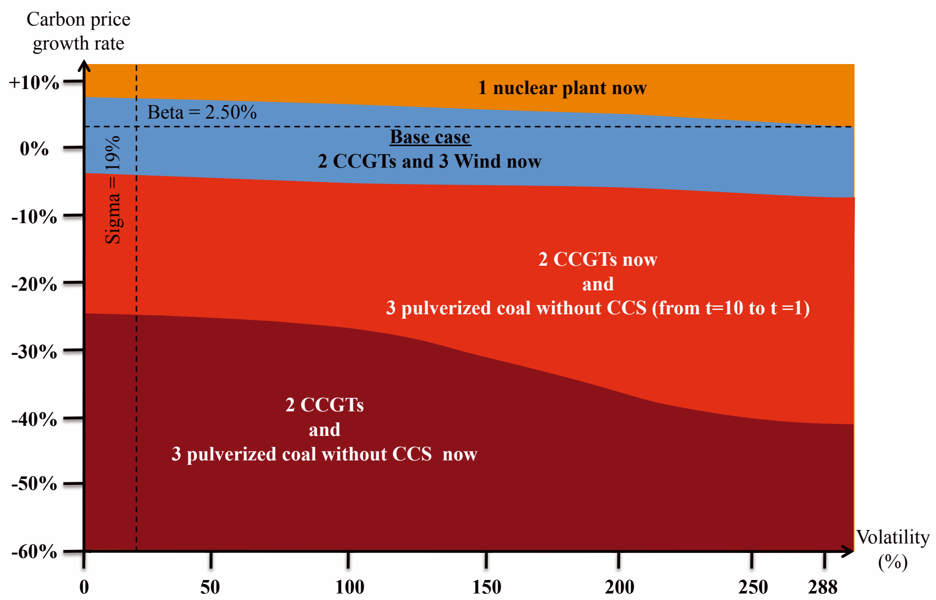

Figure 3.16: Sensitivity of investment decisions to carbon price volatility and growth rate

The picture is divided in four layers:

- For a carbon price growth rate above 7.5% in a deterministic environment or above 2.5% in an unusually highly volatile environment (constant annual volatility above 288%), the investment of choice is a single nuclear power plant now (orange area).

- For a carbon price growth rate between -3.4% and 7.4% in a deterministic environment or between -5.5% and 3.5% in a highly volatile environment (constant annual volatility above 250%), the investment of choice is the base case (blue area).

- In the light red area, the investment suggested by the model is two CCGTs now and three pulverized coal-fired plants without CCS between t=1 and t=10. There, we see the interaction between the volatility and the growth rate parameter (real option waiting effect). As volatility increases, the area extends to lower growth rates (from -25% to -50%), which indicates uncertainty regarding the profitability of coal-fired generation (potential for a significant change in carbon price, even a very small chance), even though the sole growth rate parameter would indicate the contrary.
- In the dark red area, the investment suggested is two CCGTs and three pulverized coal-fired plants without CCS now. Contrary to the previous layer, the area shrinks as volatility increases.

3.3.2 EU ETS features

Another type of sensitivity tests we run in our model considers policy instrument additions to the EU ETS (price control measures), changes in the length of the EU ETS, intertemporal flexibility and the level of the new entrants reserve.

Carbon price control measures

In the context of the economic and financial crises that begun mid-2008, market observers, worried that a collapse of carbon prices would undermine the environmental objectives of the scheme, advocated for price floor mechanisms. The modalities of a price floor support scheme range from a simple price threshold under which the carbon price must not go to more elaborate scheme involving a time-varying threshold or indexation on some reference data. Conversely, in case the price of carbon boomed (as was initially expected in ex ante EU ETS simulations[24]), one may conceive safety valve mechanisms (price cap) to avoid too heavy a burden on compliance buyers (and possibly on society as a whole). Finally, more complex structures like tunnels (cap plus floor) are a possibility.

In order to identify the impact of price control measures on investment decisions, we retrofitted the real options model to explicitly account for the existence of carbon price control measures. In particular, we consider the following equation for the price of carbon:

$$p_t^c \quad = \quad \min[p_t^{c+},\ \max(\hat{p}_t^c,\ p_t^{c-})]$$

[24]See Springer (2003, [113]) and Springer and Varilek (2004, [114]) for more details.

In this equation, the carbon price takes the value of (1) the carbon price cap, p_t^{c+}, should the simulated carbon price rise above the cap, (2) the carbon price floor, p_t^{c-}, should the simulated carbon price drop below the floor and (3) the value of the simulated carbon price else. We further refined the model to account for market phase-specific caps and floors.

Figure 3.17 illustrates the effect of various levels of cap and floor starting in 2010 on investment decisions and Figure 3.18 illustrates the effect of various levels of cap and floor starting in 2021 (phase IV) on investment decisions.

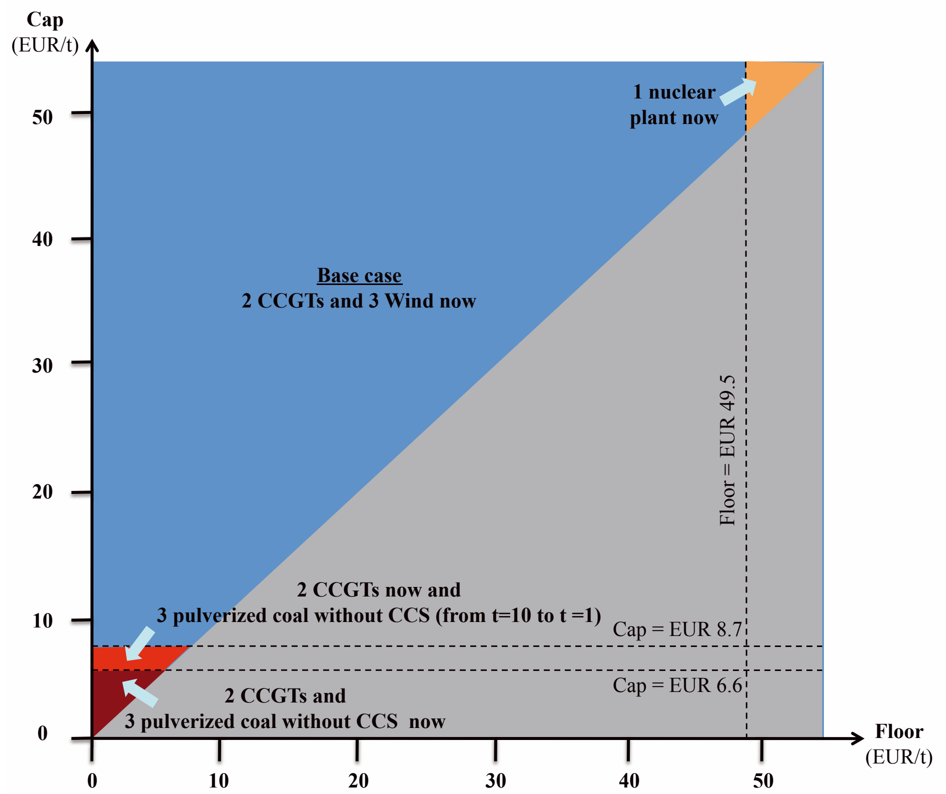

Figure 3.17: Sensitivity of investment decisions to cap and floor levels - unique over horizon

With this new element for analysis, we are able to track the impact of:

- a price cap only (by setting the price floor level to zero). For instance, on Figure 3.17 and 3.18, the upper axis indicates the impact of a carbon price cap;
- a price floor only (by setting the price cap to infinity);
- a price tunnel;

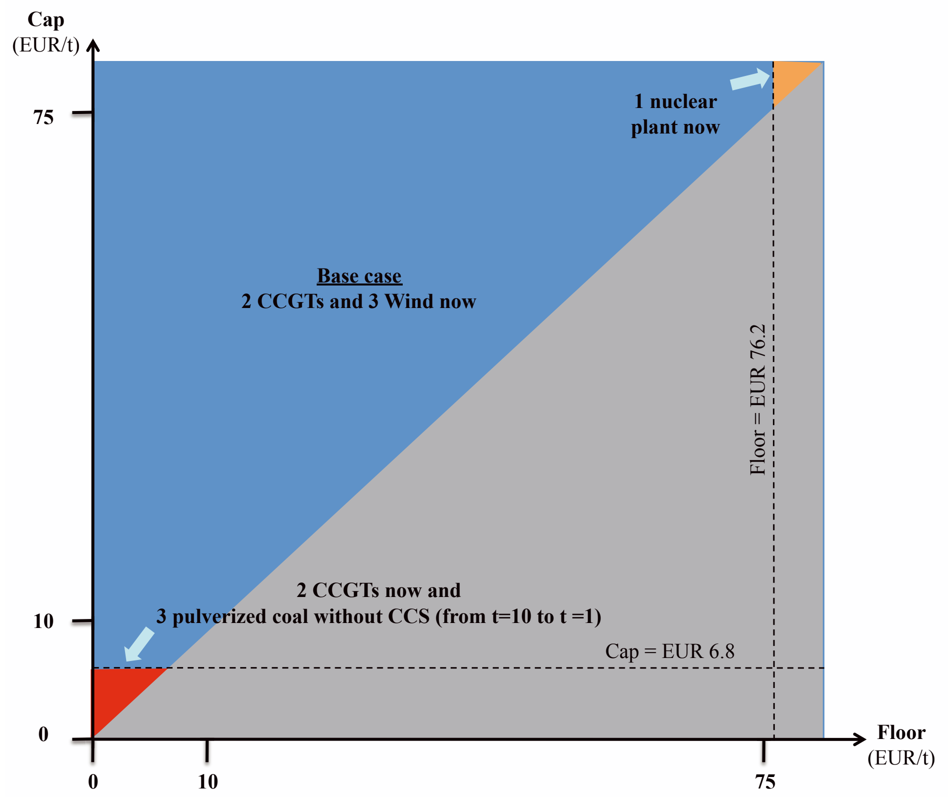

Figure 3.18: Sensitivity of investment decisions to cap and floor levels - unique and starting in phase IV

- a tax replacing the EU ETS (by setting the price floor identical to the price cap). The impact of the replacement of the carbon price by a fixed tax is to be found on Figure 3.17 when the replacement is performed now and on Figure 3.18 when the replacement occurs at the beginning of phase IV. On both graphs, the line to look at is the one going from the origin to the upper-right corner.

- the end of the EU ETS in a specific year (by setting the price cap to zero starting in a given year).

We were able to identify four investment areas[25]:

- **Invest in carbon-emitting generation right now:** This area represents attempts to water down the carbon constraint to the extent that the worst combination for emissions (given our initial assumptions) is picked. In this dark red area, the optimal investment combination is to invest in two CCGTs and three coal-fired plants without

[25]The grey area indicates non-feasible combinations (floor higher than cap).

CCS now. This can be achieved by (1) suppressing the EU ETS now, (2) setting the carbon price cap up to EUR 6.6, (3) setting up a price tunnel whose upper bound goes up to EUR 6.3 and whose lower bound is anywhere below or (4) replacing the EU ETS by a tax going up to EUR 6.6. This area cannot be reached when the policy change occurs in phase IV.

- **Invest in carbon-emitting generation cautiously:** Again, this area represents attempts to water down the carbon constraint. In this light red area, the optimal investment combination is therefore to invest in two CCGTs now and three coal-fired plants without CCS over time. This can be achieved by (1) suppressing the ETS in phase IV, (2) setting the carbon price cap between EUR 6.6 and EUR 8.7 now (or below or at EUR 6.8 in phase IV), (3) setting up a tunnel whose upper bound is set between to EUR 6.6 and EUR 8.7 now (or at or below EUR 6.8 in phase IV) and whose lower bound is set anywhere below or (4) replacing the ETS by a tax between EUR 6.6 and EUR 8.7 now (or below or at EUR 6.8 in phase IV).
- **Base case:** The blue area is the base case area. Here, any attempt to control carbon prices affects investment profitability but triggers no changes in the optimal investments and related timing. This can be achieved by (1) setting either no cap at all or a cap above EUR 8.7 now (or above EUR 6.8 in phase IV), (2) setting up a tunnel whose upper bound is set anywhere above EUR 8.7 now (EUR 6.8 in phase IV) and whose lower bound is set anywhere below EUR 49.5 now (below EUR 76.2 in phase IV) or (3) replacing the ETS by a tax between EUR 8.7 and EUR 49.5 now (or between EUR 6.8 and EUR 76.2 in phase IV).
- **Nuclear generation:** In the orange area, the optimal investment is one nuclear power plant now given that the carbon constraint was made so strong that any carbon-emitting generation is shunned. Price control measures can be costly nevertheless. This can be achieved by (1) setting a carbon price floor at or above EUR 49.5 now (EUR 76.2 in phase IV), (2) setting up a tunnel whose upper bound is set anywhere (above the lower bound) and whose lower bound is set at or above EUR 49.5 now (EUR 76.2 in phase IV) or (3) replacing the ETS by a tax at or above EUR 49.5 now (EUR 76.2 in phase IV).

Length of the EU ETS

Simulations of optimal investment decisions when the EU ETS policy is terminated in various years indicates the following three insights:

- **When the EU ETS ends up to 2013**, the investor faces no real carbon constraint apart from a temporary cost. Unsurprisingly, the investor turns to the investment combination where he invests in two CCGTs and three coal-fired plants without CCS right now.

- **When the EU ETS ends between 2014 and 2026**, the carbon constraint is getting more material and starts to affect investment decision-making. Compared to the first case, the investment in the three coal-fired plants without CCS is postponed. The later the EU ETS early termination, the larger is the delay. In fact, the delay coincides with construction length. Given that coal-fired plants without CCS take four years to be built, the plants are only commissioned when the EU ETS is ended.
- **When the EU ETS ends after 2026**, the policy continuation ensures that the base case is the optimal decision the investor can take. In other words, the carbon constraint is enough to render this combination the most profitable (with the initial calibration).

The early termination could be highly detrimental to power plant investment decisions and the locking-in of carbon emissions. Yet, it should be stressed that investment decision-making is an ongoing process. As such, what prevails for our ten-year investment window should not be taken for an argument in favour of ending the EU ETS nineteen years from now.

Rather, what could be inferred is that, following our modelling assumptions, at least fifteen years of a stable EU ETS policy context are required to prevent investment choices with a higher carbon emissions lock-in potential.

These results are quite similar to Buchner (2007 [115]) and Fuss et al. (2009, [92]). Policy-wise, this indicates that announcements relative to new market phases go-ahead give strong support to the inclusion of carbon prices in investment decision-making. The existence of a trading phase implies de facto a carbon price over the length of the phase. For the moment, the ETS officially continues until 2020 (Phase III). No hints of phase IV (except for a revision of the linear effort rate in 2025) and beyond exist currently. Although ETS policy horizon are particularly important in deciding upon investment, policy-making is usually a long process and the EU ETS does not provide investment decision-makers with ETS phase beyond 2020. Still, the existence of emissions reduction targets beyond 2020 at the EU-level is indicative a policy framework supporting it and continuation of the EU ETS policy is most likely.

Intertemporal flexibility

The EU ETS authorizes banking and borrowing of allowances between trading phases. No intertemporal flexibility allowed between trading phases implies that the price of carbon should converge towards its estimated equilibrium price for the given phase (towards transaction costs in phase I for instance after the EC decision rendering banking of EUAs into phase II pointless). A perfect intertemporal flexibility between trading phases means that the current phase price takes into account next phase emissions reduction objective. Simply stated, even though each market phase has its own emissions reduction objective, phases among which perfect intertemporal flexibility exists will exhibit prices reflecting several market phases. Recognizing that emissions markets have a declining emissions cap structure between phases to achieve policy objectives, intertemporal flexibility will exclusively be with stricter phases. Therefore, a perfect intertemporal flexibility prevents price jumps from occurring by smoothing price sensitivity to cap levels.

We tested for the effect of a ban on intertemporal flexibility between phase II and III. We assumed that the EC decided that phase II objective was too low given the financial and economic turmoil and banned the carry-over of phase II allowances to phase III and the inverse operation as well. The likely effect would be a crash of phase II prices (without phase III lower supply to support prices). Then, it all depends on the level at which phase III prices restarts. Sensitivity tests performed indicate that a price above EUR 32 at the beginning of phase III would make the investor shift from the base case to the nuclear hedge now.

We performed earlier sensitivity tests to the level component of the long-term carbon price trend. Playing on intertemporal flexibility could be a way to implement such "price reset periods" when needed. Still, this comes at the price of investors' and carbon markets' confidence erosion.

New entrants reserve (NER)

During phase II of the EU ETS, allowances were almost exclusively allocated for free on the basis of grandfathering (historical emissions as a reference point). Since it was felt that older generation would be favoured, a new entrants reserve was negotiated and set aside so that new entrants (new generation capacity for incumbent firms and genuine new entrants) would benefit from free allowances like their incumbent counterparties. The NER initial level and use over time is different in Member States. In the case of added capacity falling within the scope of the directive (CCGT and pulverized coal power plants), the ability to tap into the NER would reduce carbon procurement costs (allowances are obtained for free instead of having to buy them on the markets) over phase II and possibly beyond if extra allowances are banked. Over phase III of the EU ETS, the NER concept as it prevailed during phase II will disappear given the incentive to invest in dirty generation given and that most of the allowances will be auctioned. Even with a phased-in auctioning for the power sector, a large amount of allowances will remain allocated for free.

We especially tested for the effect of a continuation of an allocation of allowances for free to new entrants in phase II. We assumed that 100% of allowances needs were covered by tapping into the new entrants reserve. We found that the base case still prevailed. Even when we further assumed that there would still be a new entrants reserve in phase III (even for plants that would be commissioned later than phase II), we found no shift from the base case to another optimal investment combination.

We conclude by saying that maintaining or interrupting the NER has indeed an impact (1) on cash flows and profitability of carbon-emitting generation and (2) on relative competitiveness of carbon-free generation but not to the extent of a change in optimal investment decisions.

We eluded the question of passthrough as we assumed the investor was a price-taker and that pass-through regulation was rather a matter of energy regulation than the a job for the DG CLIMA of the EC. Additionally, sensitivity tests to the correlation factor between the carbon price and power prices indicated no changes in investment decisions.

3.3.3 Non-ETS features

Typically, technology-dedicated support schemes are put into place to promote R&D, pilot stage investment and later stage deployment of non-mature technologies by means of incentives: feed-in tariffs or premia, tender schemes, grants, tradable certificates, etc. The study of the impact of initiation, modification and (early) termination of such schemes are critical to investment-decision making.

Changes to renewables support

Regarding offshore wind, the base case feed-in tariff scheme is ten years at EUR 130/MWh followed by ten years at EUR 64/MWh followed by exposure to the baseload power price for the remaining five years. With this configuration, the optimal decision is the base case, in which the investor invests in three wind offshore plants now (along with two CCGTs).

We tested for policy changes that occurred during our ten-year investment window and performed a joint sensitivity study of investment decisions to (1) the length of the first technology support period (initially ten years) and (2) the level of support during this first technology support period (EUR

130/MWh). Figure 3.19 indicates the different areas of suggested investment combination and associated timing in function of various feed-in tariffs (FIT) levels and length of support. In Figure 3.19, we identify three areas:

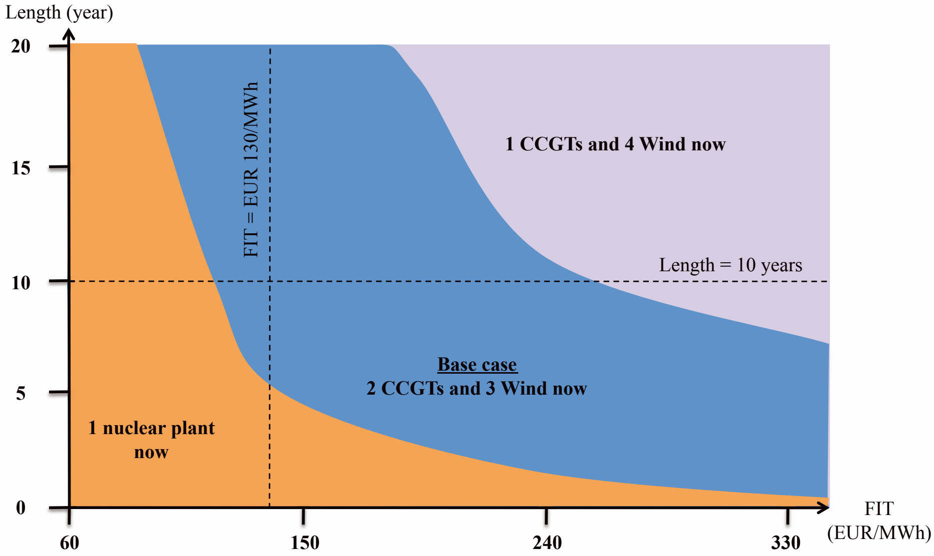

Figure 3.19: Sensitivity of investment decisions to FIT level and support length

- **Over-support area**: in the pink area, the support level and / or length of support are such that wind becomes the most profitable technology at quite a cost. The optimal menu becomes to invest now in four offshore wind parks and one CCGT (with the remaining "budget tail").
- **Current support area**: in the blue area, the investor sticks to the base case but his cash flows are nevertheless affected. For instance, instead of ten year at EUR 130/MWh, identical optimal investments can be attained with only five years at this level or ten years at only EUR 110/MWh.
- **Insufficient support area**: in the orange area, the FIT is not enough to provide the incentive to invest in offshore wind parks and investors turn to the single nuclear power plant now.

We also tested for the same sensitivity in a case where the investor could not or would not invest in nuclear generation (see Figure 3.20). This makes particularly sense given the consequences in Europe of the Fukushima incident (ban on nuclear generation in Germany, referenda or moratoria in other European member states). Figure 3.20 indicates the different areas of suggested investment combination and associated timing in function of various feed-in tariffs (FIT) levels and the length of this support - this time excluding the possibility to invest in nuclear power plants. We observe two

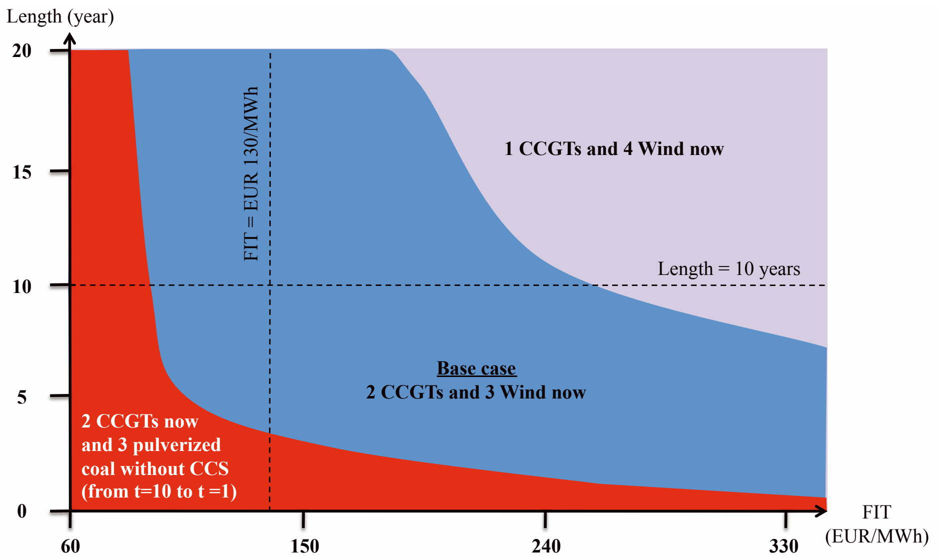

Figure 3.20: Sensitivity of investment decisions to FIT level and support length (excluding nuclear)

major differences with the initial assumptions: first, the base case area is larger by the extension of the left border indicating that cheaper FITs might suffice to trigger the base case and second, instead of the nuclear hedge, the leftmost combination is two CCGTs and three pulverized coal plants without CCS (the most emitting combination in our configuration).

While in the first case, removal of FITs would have shifted investment to the carbon-free nuclear option (which was acceptable as regards emissions) - in the second case, the shift is directed toward approximately 67 MtCO2e more. In the latter case, we clearly see the need for FIT of significant levels to prevent such investments in addition of the EU ETS.

CCS support

Figure 3.21 indicates the different areas of suggested investment combination and associated timing in function of various CCS support levels and carbon price growth rates. Our initial calibration indicates that a grant of at least EUR 959 million per coal-fired plant was needed to shift from the base case to the optimal decision being to invest in two CCGTs and two coal-fired plants with CCS now. On a single plant basis, this still represents nearly 54% of the investment costs.

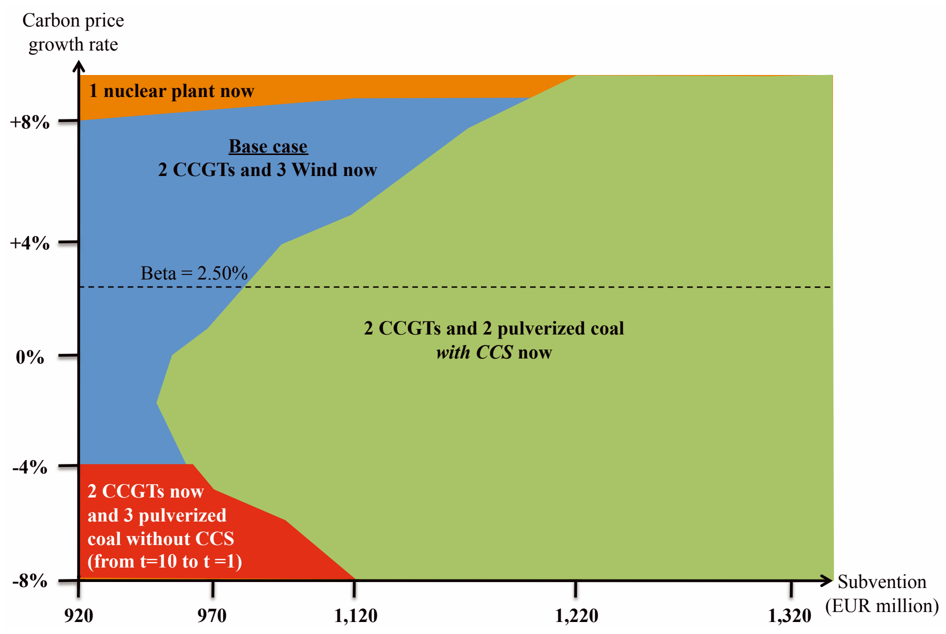

Figure 3.21: Sensitivity of investment decisions to CCS subvention level and carbon price growth rate

The rationale behind the high support level is that the investor needs to make up for (1) the fuel efficiency loss compared to the coal-fired plant without CCS, (2) the higher initial investment cost and (3) a lower capacity factor compared to the coal-fired plant without CCS and the CCGT. In other words, the investor needs to make up for the profitability differential with the next most profitable technology in the power plants' "pecking order".

Further, we related the CCS support level to the carbon price growth rate in a joint sensitivity study. It is found that until support levels of at least EUR 959 million are reached, no changes in favour of CCS is performed. Above this level and progressively, the base case (and the light red area with the high carbon content for negative carbon price growth rates) tends to be crowded out by the combination involving CCS (the green area). Nevertheless at carbon price growth rates above 8%, the combination favoured is the single nuclear power plant now unless CCS plants are financed up to 67%.

A potential explanation to the late and slow penetration of coal-fired generation with CCS is that, as the carbon price growth rate increase, (1) coal-fired plants with CCS are less profitable (with a capture rate of 90%, a slight exposure remains), (2) CCGT is even less profitable and (3) coal-fired without CCS is way less profitable. In all cases, carbon-emitting generation profitability is affected. At the same time, nuclear and wind offshore become more competitive. Things might change as the CCS capture rate increases (for the moment, it was assumed at 90%).

An area where CCS support of that extent could become interesting is in case of a major EU ETS failure (with a constant growth rate below minus 4%). In that case, CCS grants for CCS would prevent the emissions of 55 MtCO2e which would be equivalent to EUR 38/ton of CO2e[26]. Our results are coherent with existing literature on this topic (Abadie and Chamorro, 2008 [87]).

Sensitivity tests to other parameters

As a typical check, we performed a sensitivity study to the discount rate used in the model. The initial calibration (6%) indicated the base case as the most profitable combination.

We find that between 0.0% and 1.3% the investment combination chosen is a single nuclear power plant. For this investment, the lower the discount rate, the later the investment. Recall that the nuclear power plant is the most capital-intensive investment alternative and that extremely low discount rates implies that cash flows ten years from now are almost as valuable as today's cash flows. Given that cash flows gets more profitable as time passes (baseload power prices increase over time), the optimal choice is to invest the latest. Between 1.4% and 5.1%, the optimal investment is a single nuclear power plant now. The discount rate is high enough to counterbalance the baseload growth rate. Between 5.2% and 9.3%, the model indicates the base case as the investor's choice. In the 9.4 - 19.5% range, the wind technology, which is the second most capital-intensive technology in our calibration, becomes unprofitable. Consequently, the optimal policy is to invest only in two CCGTs now. Between 19.6% and 21.0%, the CCGT technology begins to become less profitable and the investment in the two units is delayed as the discount rate increases. Above 21.0%, no investment is undertaken as the hurdle rate is too high to ensure any profit.

We performed sensitivity tests to the correlation factor between the carbon price and power prices and found no shifts to alternative investment combinations. These changes in correlation among stochastic processes could be triggered by changes of the scope of the EU ETS with the inclusion of new sectors (aviation, shipping, forests, etc.) or greenhouse gases (N2O,

[26] 2 pulverized coal with CCS subvention (for a total of EUR 2.1 billion) instead of 3 pulverized coal.

CH4, etc.) within the EU ETS. These inclusions help extending the carbon price signal by increasing the part of the economy in which emissions are capped by a policy tool and incorporate more emissions reductions alternatives in the ETS sectors aggregate MACC. It is expected that inclusion thereof would relatively decorrelate price signals from energy fundamentals as those would be diluted in a larger set of sector-specific price drivers. Alternatively, a decorrelation of price processes could be achieved by linking directly with other ETS or by changing the rules governing offsets uses for compliance.

3.4 Conclusion

In this chapter, we laid out an analytical framework to explore corporate investment decision-making under the EU ETS and ultimately to explore scenarios on how the EU ETS is changing investment choices and timing in the European power sector. The objective of this model is to guide policymakers in identifying trigger points and levers to alter climate policy outcomes.

The framework builds on the real options approach in order to take into account several characteristics of interest (uncertainty in carbon and electricity prices, flexibility in investment choices and timing, and capital expenditure earmarking) in a comprehensive analytical framework. We explained the benefits of resorting to a real options approach over using a traditional deterministic discounted cash flow model with or without a few additional building blocks (scenarios, sensitivity tests, capital rationing, decision tree analysis, etc.).

We model carbon and power stochastic prices based on historical data and price targets from market analysts. Contrary to most of the literature, both stochastic processes are modelled as mean-reverting processes (short-term dynamic) around a linear trend (long-term dynamic) reflecting the long-run abatement cost and electricity price respectively. Moreover, the model considers various power generation technologies: coal-fired with or without CCS, CCGT, offshore wind and nuclear.

The analytical framework we developed contributes to the literature by incorporating capital expenditure earmarking, adding a budget constraint to the optimization routine. The model thus does a better job at mimicking corporate investment decision-making. The base case following the initial calibration indicates that investing in CCGTs now is optimal. We incorporate an additional constraint on allowable combinations to elicit the timing and technology shift effects of policy scenarios by running sensitivity tests.

See figure 3.22 for a representation of the impact of amendments to climate policies on investment decisions and associated locked-in CO2 emissions. The summary graph indicates the optimal investment thresholds for various

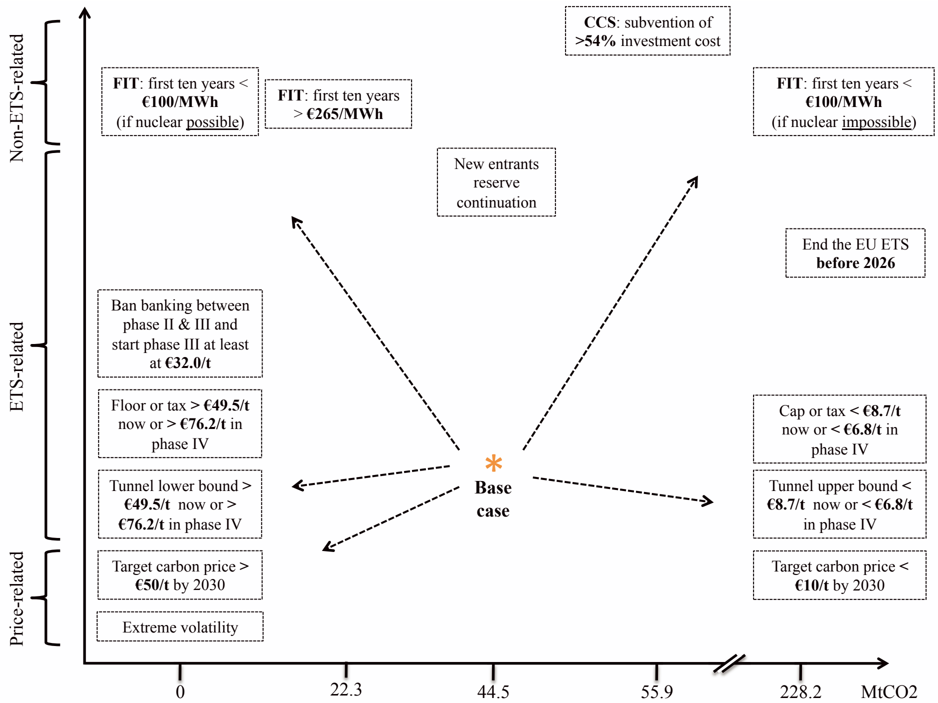

Figure 3.22: Impact of climate policy amendments to locked-in CO2 emissions

changes in European climate policies: (1) changes to modify the existing carbon price dynamic (short-term and long-term), (2) changes to the EU ETS characteristic (price control mechanisms, intertemporal flexibility, policy horizon and new entrants reserve) as well as (3) changes to offshore wind feed-in tariffs and CCS subvention levels. The thresholds indicated are most often on a single change basis. From the policy-maker perspective, some changes seem more likely (ensure policy continuation over phase IV to begin with) to implement than others, which are hard to reach, entail secondary effects (erratic volatility) or come at too high a cost (CCS).

The first set of sensitivity tests investigates the impact of changes in the price of carbon on investment choices. Looking at the short-term dynamic of the price (volatility and the speed with which prices revert to the long-run trend), the model indicates that a sustained extreme volatility and / or almost random price behaviour is to be attained for investors to delay their investment in carbon-emitting generation or to turn to carbon price hedges (offshore wind and nuclear). While the short-term dynamic is very important for corporate compliance, operations and trading activities, we find that it is of little guidance for investment decision-making. Turning to the long-run price dynamic (linear trend comprised of a starting price level and a growth rate), the model suggests that changes in the long-run price trend or indications thereof impact fundamentally carbon costs and are critical to investors. High target prices (minimum EUR 50/ton of CO2e by 2030) dictate investment in carbon price hedges (offshore wind and nuclear) while lower target prices dictate shorter delays to invest in carbon-emitting generation (below EUR 10/ton of CO2e by 2030).

The second set of sensitivity tests investigates the impact of changes in the EU ETS apart from the carbon price itself. First, carbon price floor, cap or tunnel structures acts in superposition of the carbon price long-term and are useful to investment decision-making as they provide boundaries to the long run trend. The model indicates that shift to nuclear occurs when a high carbon price floor is set (EUR 49.5/ton now or EUR 76.2/ton beyond 2020). Likewise, quicker investment is carbon-emitting generation is triggered by setting a low carbon price ceiling (below EUR 8.7/ton now or EUR 6.8/ton starting 2020). Anything between those boundaries (most likely cases) affects the profitability of investments but not to the extent to alter timing or technology choices. Second, sensitivity tests indicate that if the EU ETS ends before 2026 (or if investors believe so actually), investment in carbon-emitting generation is part of the optimal investment. The earlier the end of the EU ETS, the earlier the investment in coal-fired plants. Third, we tested for the effect of a ban on intertemporal flexibility between phase II and III of the EU ETS (with crashing phase II prices and stronger phase III prices). The model indicates that starting phase III prices needed to be at least above EUR 32/ton for investors to turn to carbon price hedges. Finally, the model highlights additional profits for carbon-emitting generation from continuation and resort to a new entrants reserve but any changes to this parameter yields no changes in timing or technology.

The last set of sensitivity tests investigates the impact of changes to climate policies outside of the EU ETS (feed-in tariff for offshore wind and a grant targeting CCS). The model indicates that changes in technology-focused incentives are far more decisive in the investment decision-making process. Unsurprisingly, supporting offshore wind beyond generation costs triggers additional investment in this technology. Too low the feed-in tariff level and / or too short the length of support rule out offshore wind of the optimal investment. Instead, the investor would turn to nuclear generation, or if unable to do so, would invest in carbon-emitting generation. Regarding CCS, the model highlights high support level (up to 54% of the investment cost) to trigger investment in coal-fired generation with CCS rather than wind, thereby emitting more $CO2$ in the end.

Overall, five recommendations can derived from the model:

- The EU ETS has a moderate but central reallocation role in the pecking order of power generation investment.
- Any indication of the long-term trend is key for investment decision-making, especially elements relative to the cap (taking into account all sorts of flexibility mechanisms).
- Much discussed changes like new entrants reserve continuation, carbon price mitigation or price control mechanisms are of limited influence on investment decision-making.
- Utilities delay or cancel investments in generation depending on their expectations regarding policy outcomes. As such, building the proper expectations and communicating efficiently with utilities is of the utmost importance.
- Utilities operate in a multiple policy environment. As such, in designing and evaluating policies, the aggregate effect of a bundle of policies should be scrutinized rather than a focus on a single policy. Technology-focused incentives on top of the EU ETS trigger stronger shifts in timing and choices than the EU ETS reallocation process. Policy interaction and articulation should be kept in mind (e.g. concern over the role of EU energy efficiency policies in relation to the EU ETS in July 2011).

This type of approach can be useful to the policymakers in evaluating claims from the power sector whether policy modifications endanger investment decisions (or alter timing of commissioning because of a too high the policy uncertainty) or basically erode profits on an acceptable basis to ensure a lower potential of emissions locked-in the atmosphere. It should be noted that the model could be further improved to account for more additional sources of uncertainty, new technologies and even add operational flexibility. We leave these elements for further research. It should be stressed that even though some of the policy changes are costly, there is also some room for additional financing or amendments to climate policies in order to improve the policy signal. Among which the auctioning of carbon allowances in phase III has a large role to play. In particular if revenues from auctions could be properly earmarked.

Conclusion

The objective of this PhD thesis was to better understand the EU ETS impact on European utilities investment decisions. More precisely, this thesis explored the potential responses to deal with the carbon constraint (how have European utilities coped with the EU ETS and was investment part of the response? If not, why so and what for instead?), empirical evidence of generation investment in the European power sector (how has the EU ETS influenced the business-as-usual path of investments in the European power sector? What kind of investments were triggered? Have other factors played a more significant role?) and the specific pathways taken by the carbon price signal to influence investment decisions.

We have been approaching these questions using complementary approaches. In the first chapter, we presented the various corporate responses to the introduction of a carbon constraint using a mix of corporate and academic literature. In the second chapter, we reconstructed the investment pipeline of the five most carbon constrained European utilities during the first years of the EU ETS. Finally in the third chapter, we used a real options model to identify the pathways taken by the carbon price signal to influence investment decisions. In particular, we explored the effect of various carbon price scenarios on optimal investment decisions and formulated recommendations to policymakers. This dissertation provides insights to both academics and public and private decision-makers.

In the first chapter (*"European utilities' response to the European Union Emissions Trading Scheme"*), we focused on the introduction and evolutions of the EU ETS. Elements relative to other European climate policies and the impact of the economic and financial crisis were provided to give some background information. The chapter then discussed the three main types of responses deployed by European utilities to deal with the EU ETS. First, emissions reductions were envisaged both in the short-run by switching feedstock for boilers and reducing production or in the longer run by investing in existing generation (retrofitting, replacement and rejuvenating expenses), new generation and ultimately R&D. Second, European utilities have been largely acquiring additional compliance assets. They did so by minimising carbon procurement costs. They were involved in both the primary and secondary Kyoto offset markets. They resorted to borrowing and banking of carbon assets and finally acquired carbon allowances on the market to cover the remaining shortfall in carbon assets. Third, European utilities have been quite active to attempt to alter their compliance perimeter and change the EU ETS rules. The most important developments relate to commercial solutions developed to transfer the carbon price risk, lobbying to obtain higher emissions caps or more flexibility mechanisms, and challenging the EC and national authorities about national allocation plans and carbon price passthrough. For policymakers, three main lessons can be drawn. First, cheap compliance alternatives, like resort to fuel switching and carbon trading, did play a significant role as expected. Second, longer lived emissions reduction did not occur as much as was expected. According to compliance buyers, this was the result of a constantly changing environment without much long-term view. According to market observers, the cap, still too high, was unlikely to trigger long-lived emissions reduction. Third, some unexpected or at least less conventional responses were recorded (generation swaps and legal challenges).

In the second chapter (*"Operating and financial investments by European utilities over 2004-2009: what role for climate policies?"*), we discussed the evolution of European utilities investment pipelines. We focused on the top five most carbon constrained European utilities. We opted for a broad definition of investment considering both investment in power generation (greenfield and brownfield investment and divestment) and financial stakes taken in the power generation business. Given the difficulties in getting transparent, detailed and readily available data on corporate investment, we manually collected investment data by these five European energy groups over the 2004-2009 period. We reconstituted the realised and projected pipelines of investments and shareholding by these utilities. From 2004 to 2007, European utilities investments were only slightly influenced by the carbon constraint that was introduced. Other factors played a more decisive role like the repositioning of the European sector thanks to the liberalisation of EU power and gas markets, and environmental regulations. While some investment undertaken helped alter the BAU scenario for emissions, it turned out difficult to attribute these emissions reduction solely to the EU ETS in the absence of a counterfactual for these five entities. We also found that the impact of changes in the compliance perimeters of those entities and to whom were transferred more carbon-emitting generation assets should not be neglected. From 2008, expectations about the shift to a top-down cap-and-trade scheme based on auctioning of allowances in phase III triggered more investment-related responses on the part of regulated entities. This trend was halted or at least slowed with the beginning of the economic and financial crisis. In the most recent observations, highly carbon-emitting plants were cancelled in favour of plants emitting less or no carbon dioxide at all. Likewise, regulated entities fully used project mechanisms to foster investments in lower carbon power plants. However, we found that some of the responses were rather creative and required further monitoring (power plants built at the border of the EU with transmission lines towards European grids in particular). The main difficulty we faced in this chapter relates to data availability and quality. While voluntary disclosures helped, we found that a mandatory reporting system on power generation projects at the European scale would help policymakers assess the effectiveness of the EU ETS on power generation investment. To some extent, this supports the revision of the EC regulation concerning the notification to the EC of investment projects into energy infrastructure (Council Regulation 736/96) in favour of complementary reporting on financial, technical and environmental data.

In the third chapter (*"Impact of the EU ETS on investment in new generation: a real options approach"*), we presented the evolution of investment decision-making models and explained the difficulties but also the benefits of resorting to a real options approach compared to a traditional deterministic discounted cash flows model. The aim of this chapter was to develop carbon price scenarios and analyse their impacts on power generation investment portfolios. The model developed is able to capture both timing and technology changes in a portfolio context and provide some insights to policymakers in designing and making amendments to cap-and-trade policies with a view towards more emissions reduction by compliance buyers.

First, we found mixed evidence that changes to the carbon price were able to influence investment choices. Looking at the long-run price dynamic, the model suggests that changes in the long-run price trend or indications thereof impact fundamentally carbon costs and are critical to investors. High target prices (minimum EUR 50/ton of CO2e by 2030) dictate investment in carbon price hedges (offshore wind and nuclear) while lower target prices dictate shorter delays to invest in carbon-emitting generation (below EUR 10/ton of CO2e by 2030). Conversely, looking at the short-run price dynamic (volatility and mean reversion speed), we found little impact on investment choices unless there is some sustained extreme volatility or random price development for carbon allowances.

Second, we explored the impact of non-price EU ETS provisions or much debated proposals. Carbon price floor, cap or tunnel structures are useful to investment decision-making as they provide boundaries to the long run price trend. The model indicates a shift towards carbon price hedges like nuclear when a high carbon price floor is set (EUR 49.5/ton now or EUR 76.2/ton beyond 2020). Likewise, quicker investment in carbon-emitting generation is triggered by setting a low carbon price ceiling (below EUR 8.7/ton now or EUR 6.8/ton starting 2020). Sensitivity tests indicate that if the EU ETS was to end before 2026 (or if investors believed so actually), investment in carbon-emitting generation would be part of the optimal investment. The earlier the end of the EU ETS, the earlier the investment in coal-fired plants. Banning intertemporal flexibility between phase II and III of the EU ETS, with crashing phase II prices and stronger phase III prices starting at least at EUR 32 per ton, makes investors turn to carbon price hedges. The model highlights additional profits for carbon-emitting generation from continuation and resort to a new entrants reserve but without triggering any changes in investment timing or technology choices.

Third, the model indicates that changes in generation technology-directed incentives are very decisive in the investment decision-making process. Supporting offshore wind beyond generation costs triggers additional investment in this technology. A feed-in tariff level that is too low and / or a support length that is too short rule out offshore wind of the optimal investment portfolio in the model. Alternatively, the investor would turn to nuclear generation, or if unable to do so, would invest in carbon-emitting generation. The model highlights that high support level to CCS (with grants up to 54% of the investment cost) is required to trigger investment in coal-fired generation with CCS rather than wind.

Based on the results from the model and empirical evidence, we formulate five lessons for policymakers:

- **The EU ETS has a moderate but central reallocation role** in the pecking order of power generation investment. Other strategic considerations (repositioning of the European power sector) and investment drivers like capital costs, power prices or feed-in tariffs & grants played a bigger role.

- Any indication of the **long-term trend is key for investment decision-making**, especially elements relative to the cap (taking into account all sorts of flexibility mechanisms). Unfortunately, not everything can be done at the EU level and a driving force behind is the outcome of climate negotiations.

- **Most of the much discussed proposals** like new entrants reserve continuation, carbon price mitigation or price control mechanisms **are of limited influence on investment decision-making**. While politically harder to obtain, it ends up being more effective in terms of emissions reduction to work on ways to reduce the overall emissions cap rather than adding other building blocks.

- Utilities have been delaying or cancelling investments in generation depending on their expectations regarding policy outcomes. As such, **building the proper expectations and communicating efficiently with utilities, and compliance buyers more generally speaking, is very important**.

- Utilities operate in a multiple policy environment. When designing and evaluating policies, the **aggregate effect of a bundle of policies should be scrutinized rather than a focus on a single policy**. Technology-focused incentives on top of the EU ETS trigger stronger shifts in timing and choices than the EU ETS reallocation process. Policy interaction and articulation should be kept in mind (e.g. concern over the role of EU energy efficiency policies in relation to the EU ETS in July 2011).

Beyond the immediate insights gained in the various chapters, the two main general lessons learnt were that the **expected future policy framework was at least as important as the existing one for investment decisions** and that **unexpected creative responses are to be expected when dealing with innovative and complex climate policies**. These two elements should be of high importance to carbon markets policymakers and regulators. This PhD thesis aimed at providing an increased understanding of the impact of the carbon price signal on European utilities investment decisions. The three chapters contributed to addressing various key dimensions of this overall question. Still, elements relative to some data availability or quality issues and modelling choices deserve a few more comments.

Concerning chapter 1, had we had access to comprehensive, comparable and reliable datasets on corporate responses, we would have been able to quantify the resort to various corporate responses to the EU ETS among the largest European utilities. Even given the difficulties in obtaining reliable and useful investment data from surveyed utilities in the second chapter, the dissertation would benefit from covering the next five most carbon constrained utilities as well as some smaller entities or unique installations like the 3,960 MW Drax coal-fired power station. Likewise, more insights on emissions reduction could be obtained by having a benchmark scenario to compare empirical data with. Finally, in attempting to attribute the commissioning of various plants to the EU ETS or other factors, a panel analysis might be useful. That analysis could use global and EU-wide drivers (technology costs, economic environment and EU policies), Member state and region-wide drivers (technology costs, economic environment, policies and power sector organisation) and utility-specific drivers (generation mix, proxies for strategy, positioning, etc.) as regressors.

In the third chapter, a more comprehensive analytical framework could be obtained by (1) adding further sources of uncertainty (coal and natural gas stochastic price processes), (2) taking into account other real options to value in the model (CCS-retrofitting over the lifetime of a plant, fuel switching like gas vs. coal, co-firing different percentages of biomass, ability to mothball plant, shut down plants, etc.), (3) adding new generation technologies from the beginning and over time, (4) modelling the impacts of overall and own generation capacity commissioning on market prices and generation costs (learning curve effects especially important for CCS and renewables), (5) testing for alternative long-term carbon price trends (other than a linear one) and (6) improving the algorithm (more efficient coding allowing for more dimensions to be taken into account and quicker calculations). These improvements might be able to capture additional insights for policymakers.

Appendices

.1 Survey table of carbon price processes

Table 16: Survey of carbon price stochastic modelling

	Process	Start value	Expected	Drift Risk-adjusted	Reversion speed	Reversion level	Diffusion Instantaneous volatility	Jump	Fitting data
		α^c	β^c	$\beta^c - \lambda^c$	θ^c	$(h_t^c)^*$	σ^c		
Abadie and Chamorro (2008)	GBM	EUR 18/t in 2007	-	3.08%	-	-	46.83%	-	1325 daily prices of the five Futures contracts maturing in phase II
Chladná (2007)	GBM	USD 5/t in 2010	3.63%	-	-	-	16.60%	-	IIASA MESSAGE model
Fuss et al. (2008) and Szolgayova et al. (2008)	GBM	EUR 5/t	5.68%	-	-	-	2.87%	-	GHG shadow prices from IIASA GGI scenario database
Fuss et al. (2009)	GBM with and without GBM jump	USD 5/t	5.00%	-	-	-	0 to 30%	frequency is from 0 to 20 years	GHG shadow prices from IIASA GGI scenario database
Yang & Blyth (2007); Blyth et al. (2007) and Yang et al. (2008)	GBM with Poisson jump	undisclosed	undisclosed	-	-	-	7.75%	+/- 100% size and once 10 years from now	In order to follow IEA scenario projections 15 years from now
Yang & Blyth (2008)	MR	USD 15/t in 2005	-	-	0.14	EUR 15/t and 15% p.a.	50.00%	-	In order to follow IEA scenario projections 15 years from now
Laurikka & Koljonen (2006)	MR	EUR 7/t in 2005	-	-	0.20	EUR 20/t or EUR 1/t in 2013	10 or 40%	-	Judgemental input

.2 LSM methodology

In this appendix, we present simpler case studies to grasp how (1) the capital rationing constraint and (2) the price uncertainty can be handled in the model presented.

3-period 2-technology deterministic case

In order to illustrate how to solve the capital rationing issue, we detail calculations for a 3-period deterministic case. We consider two technologies, A and B, with investment costs of I^A and I^B irrespective of time. We are constrained by a budget $\bar{b}$. We may invest in a combination of technologies now, next year or two years from now. To do so, we incur investment costs and benefit from resulting NPVs.

We assume the following: $e^{-r} = 0.909$; $\bar{b} = 1{,}000$; $I^A = 400$; $I^B = 700$; $NPV_t^A = 200$, $\forall t$; $NPV_t^B = 300$ for $t = \{0; 1\}$ and $NPV_t^B = 500$ for t=2.

Finding the allowed investment combinations

The first step entails determining what are the allowed investment combinations. We are constrained by the capital rationing so that $x_t \leq b_t$, $\forall t$. Denoting Q^A and Q^B, the quantity of technologies we invest in, we must satisfy:

$$x_t = I^A.Q^A + I^B.Q^B \leq b_t$$

Here, we easily see that the control variable can take the following values:

$$\begin{aligned} x_t &\in \{\ 0;\ I^A;\ I^B;\ 2.I^A\} \\ &\in \{\ 0;\ 400;\ 700;\ 800\} \end{aligned}$$

And the budget can therefore take the following values:

$$\begin{aligned} b_t &\in \{\ \bar{b} - 2.I^A;\ \bar{b} - I^B;\ \bar{b} - I^A;\ \bar{b}\} \\ &\in \{\ 200;\ 300;\ 600;\ 1000\} \end{aligned}$$

At t=2

We start from the last decision node at t=2. The value function takes the following form:

$$V_2(b_2) = \max_{x_2} \{f_2(b_2, x_2)\}$$

At the last decision node, we have no continuation value since unused budget is assumed to have no value. We consider all the possible budget levels and determine the value function accordingly[27]:

$$
\begin{aligned}
V_2(\bar{b}-2.I^A) &= \max_{x_2}\left\{f_2(\bar{b}-2.I^A,0)\right\}\\
&= 0 \text{ with } x_2^*{=}0.\\
V_2(\bar{b}-I^B) &= \max_{x_2}\left\{f_2(\bar{b}-I^B,0)\right\}\\
&= 0 \text{ with } x_2^*{=}0.\\
V_2(\bar{b}-I^A) &= \max_{x_2}\left\{f_2(\bar{b}-I^A,0); f_2(\bar{b}-I^A,I^A)\right\}\\
&= \max_{x_2}\left\{0; NPV_2^A\right\}\\
&= \max_{x_2}\left\{0; 200\right\}\\
&= 200 \text{ with } x_2^*{=}I^A.\\
V_2(\bar{b}) &= \max_{x_2}\left\{f_2(\bar{b},0); f_2(\bar{b},I^A); f_2(\bar{b},I^B); f_2(\bar{b},2.I^A)\right\}\\
&= \max_{x_2}\left\{0; NPV_2^A; NPV_2^B; 2.NPV_2^A\right\}\\
&= \max_{x_2}\left\{0; 200; 500; 400\right\}\\
&= 500 \text{ with } x_2^*{=}I^B.
\end{aligned}
$$

At t=1

We move one step back in time to t=1. The value function now takes the following form since there is a continuation value component involved:

$$V_1(b_1) = \max_{x_1}\left\{f_1(b_1,x_1) + e^{-r}.V_2(b_1 - x_1)\right\}$$

[27] For the first two budget levels, only one possibility remains, that is to do nothing/wait. The three other possible choices make us exhaust the budget limit.

We consider all the possible budget levels and determine the value function accordingly:

$$\begin{aligned}
V_1(\bar{b}-2.I^A) &= \max_{x_1}\left\{f_1(\bar{b}-2.I^A,0)+e^{-r}.V_2(\bar{b}-2.I^A)\right\} \\
&= 0 \text{ with } x_1^*{=}0. \\
V_1(\bar{b}-I^B) &= \max_{x_1}\left\{f_1(\bar{b}-I^B,0)+e^{-r}.V_2(\bar{b}-I^B)\right\} \\
&= 0 \text{ with } x_1^*{=}0. \\
V_1(\bar{b}-I^A) &= \max_{x_1}\left\{f_1(\bar{b}-I^A,0)+e^{-r}.V_2(\bar{b}-I^A);\right. \\
&\quad \left. f_1(\bar{b}-I^A,I^A)+e^{-r}.V_2(\bar{b}-2.I^A)\right\} \\
&= \max_{x_1}\left\{0+e^{-r}.NPV_2^A;NPV_1^A+0\right\} \\
&= \max_{x_1}\{182;200\} \\
&= 200 \text{ with } x_1^*{=}I^A. \\
V_1(\bar{b}) &= \max_{x_1}\left\{f_1(\bar{b},0)+e^{-r}.V_2(\bar{b});\right. \\
&\quad f_1(\bar{b},I^A)+e^{-r}.V_2(\bar{b}-I^A); \\
&\quad \left. f_1(\bar{b},I^B)+e^{-r}.V_2(\bar{b}-I^B);f_1(\bar{b},2.I^A)+e^{-r}.V_2(\bar{b}-2.I^A)\right\} \\
&= \max_{x_1}\left\{0+e^{-r}.NPV_2^B;NPV_1^A+e^{-r}.NPV_2^A;\right\} \\
&\quad \left\{NPV_1^B+0;2.NPV_1^A+0\right\} \\
&= \max_{x_1}\{455;381;300;400\} \\
&= 455 \text{ with } x_1^*{=}0.
\end{aligned}$$

At t=0

We move one step back in time to t=0 (now). The value function again takes the following form:

$$V_0(b_0)=\max_{x_0}\left\{f_0(b_0,x_0)+e^{-r}.V_1(b_0-x_0)\right\}$$

Compared to t=1 and t=2, we only have one possible budget level, $\bar{b}$, the initial endowment.

$$\begin{aligned}
V_0(\bar{b}) &= \max_{x_0}\left\{f_0(\bar{b},0)+e^{-r}.V_1(\bar{b});f_0(\bar{b},I^A)+e^{-r}.V_1(\bar{b}-I^A);\right. \\
&\quad \left. f_0(\bar{b},I^B)+e^{-r}.V_1(\bar{b}-I^B);f_0(\bar{b},2.I^A)+e^{-r}.V_1(\bar{b}-2.I^A)\right\} \\
&= \max_{x_0}\left\{0+e^{-2r}.NPV_2^B;NPV_0^A+e^{-r}.NPV_1^A;\right. \\
&\quad \left. NPV_0^B+0;2.NPV_0^A+0\right\} \\
&= \max_{x_0}\{413;381;300;400\} \\
&= 413 \text{ with } x_0^*{=}0.
\end{aligned}$$

The optimal path

$V_0(\bar{b})$ represents the maximum value (EUR 413 million) that can be attained in the investment framework considered. The optimal path represents the decisions that must be taken sequentially in order to realize that maximum value. At t=0, the optimal decision is to wait (x_0^*=0), the budget remains intact. Moving forward in the tree, we look for $V_1(\bar{b})$ and again the optimal decision is to wait (x_1^*=0). Moving to the last decision node, we look for $V_2(\bar{b})$ and find that the optimal decision is to invest in one unit of technology B (x_2^*=I^B).

The maximum attainable gain is realized by purchasing one unit of technology B two years from now. A now-or-never DDCF framework would have yield a myopic investment in two units of technology A now, EUR 13 million less than accounting for the timing option.

3-period 2-technology stochastic case

We now add uncertainty to the NPV of one of the technologies. In particular, we generate eight price paths for one source of uncertainty (the price of baseload power). This source of uncertainty only pertains to technology B. Technology A has the same NPV whenever we decide to invest: NPV_t^A = 250 ,$\forall t$. Table 17 compiles the eight price paths generated for the source of uncertainty assumed here. Note that the price of baseload power at t=0 is known for sure[28]. The set of stochastic state variables, S_t^i, denotes here solely the price of baseload power at time t on price path i.

Table 17: Illustrative case - Price paths for baseload power

S_t^i	t=0	t=1	t=2	t=3	...	t=43
1	50.52	53.29	54.80	57.51	...	150.89
2	50.52	54.05	55.92	58.43	...	159.45
3	50.52	54.24	55.87	58.72	...	154.30
4	50.52	53.20	56.18	59.57	...	167.61
5	50.52	53.81	56.04	57.90	...	151.14
6	50.52	54.69	57.89	59.35	...	154.80
7	50.52	53.04	54.84	57.08	...	153.14
8	50.52	53.88	57.08	59.80	...	152.36

Based on those price paths, we obtain eight NPV paths for technology B. We denote $NPV_t^{B,i}$, the NPV of technology B at time t on path i. Table 18 presents the hypothesized eight NPV paths for technology B.

The value function now takes the following form:

$$V_t(b_t, S_t^i) = \max_{x_t} \left\{ f_t(b_t, x_t, S_t^i) + e^{-r}.\mathbb{E}_t^Q[V_{t+1}(b_t - x_t, \tilde{S}_{t+1}^i)] \right\} \ , \forall i \text{ and } \forall t.$$

[28] A high growth rate has been retained for illustrative purpose.

Table 18: Illustrative case - Implied NPV paths for technology B

$NPV_t^{B,i}$	t=0	t=1	t=2
1	278	372	461
2	495	598	699
3	321	417	508
4	751	865	976
5	261	354	444
6	573	674	767
7	241	337	430
8	502	597	686

And at expiration

$$V_T(b_T, S_T^i) = \max_{x_T} \left\{ f_T(b_T, x_T, S_T^i) \right\} \ \ , \forall i.$$

At t=2

We start from the last decision node at t=2. The value function takes the following form:

$$V_2(b_2, S_2^i) = \max_{x_2} \left\{ f_2(b_2, x_2, S_2^i) \right\} \ \ , \forall i.$$

At the last decision node, we have no continuation value since unused budget is assumed to have no value. We consider all the possible budget levels and determine the value function accordingly:

$$\begin{aligned}
V_2(\bar{b} - 2.I^A, S_2^i) &= \max_{x_2} \left\{ f_2(\bar{b} - 2.I^A, 0, S_2^i) \right\} \\
&= 0 \text{ with } x_2^* = 0 \text{ and } \forall i. \\
V_2(\bar{b} - I^B, S_2^i) &= \max_{x_2} \left\{ f_2(\bar{b} - I^B, 0, S_2^i) \right\} \\
&= 0 \text{ with } x_2^* = 0 \text{ and } \forall i. \\
V_2(\bar{b} - I^A, S_2^i) &= \max_{x_2} \left\{ f_2(\bar{b} - I^A, 0, S_2^i); f_2(\bar{b} - I^A, I^A, S_2^i) \right\} \\
&= \max_{x_2} \left\{ 0; NPV_2^A \right\} \\
&= \max_{x_2} \left\{ 0; 250 \right\} \\
&= 250 \text{ with } x_2^* = I^A \text{ and } \forall i.
\end{aligned}$$

The untapped budget level case (b_2=$\bar{b}$) is the only one allowing investment in technology B and hence featuring uncertainty.

$$\begin{aligned}
V_2(\bar{b}, S_2^i) &= \max_{x_2} \left\{ f_2(\bar{b}, 0, S_2^i); f_2(\bar{b}, I^A, S_2^i); f_2(\bar{b}, I^B, S_2^i); f_2(\bar{b}, 2.I^A, S_2^i) \right\} \\
&= \max_{x_2} \left\{ \ 0; \ NPV_2^A; \ NPV_2^{B,i}; \ 2.NPV_2^A \right\}
\end{aligned}$$

In table 19, we detail the investment alternatives at t=2 when the budget is full and highlight in bold the maximum value and associated decision taken.

Table 19: Illustrative case - Decision nodes at t=2 and optimal decision for untapped budget

Path	0	NPV_2^A	$NPV_2^{B,i}$	$2.NPV_2^A$	x_2^*
1	0	250	461	**500**	$2.I^A$
2	0	250	**699**	500	I^B
3	0	250	**508**	500	I^B
4	0	250	**976**	500	I^B
5	0	250	444	**500**	$2.I^A$
6	0	250	**767**	500	I^B
7	0	250	430	**500**	$2.I^A$
8	0	250	**689**	500	I^B
average	0	250	**622**	500	I^B

In tables 20 and 21, we summarize the value functions and optimal decisions for each budget level and each path at t=2.

Table 20: Illustrative case - Value function vs. budget level at t=2

Path	$b_2 = \bar{b} - 2.I^A$	$b_2 = \bar{b} - I^B$	$b_2 = \bar{b} - I^A$	$b_2 = \bar{b}$
1	0	0	250	500
2	0	0	250	699
3	0	0	250	508
4	0	0	250	976
5	0	0	250	500
6	0	0	250	767
7	0	0	250	500
8	0	0	250	689

Table 21: Illustrative case - Optimal decision vs. budget level at t=2

Path	$b_2 = \bar{b} - 2.I^A$	$b_2 = \bar{b} - I^B$	$b_2 = \bar{b} - I^A$	$b_2 = \bar{b}$
1	0	0	I^A	$2.I^A$
2	0	0	I^A	I^B
3	0	0	I^A	I^B
4	0	0	I^A	I^B
5	0	0	I^A	$2.I^A$
6	0	0	I^A	I^B
7	0	0	I^A	$2.I^A$
8	0	0	I^A	I^B

At t=1

The value function now takes the following form:

$$V_1(b_1, S_1^i) = \max_{x_1} \left\{ f_1(b_1, x_1, S_1^i) + e^{-r}.\mathbb{E}_1^Q[V_2(b_1 - x_1, \tilde{S}_2^i)] \right\} \ ,\forall i.$$

Note that the exercise decision at t=1 cannot exploit knowledge of the future (i.e. the value taken at t=2) on a given path. We are not replacing a stochastic problem by 8 single deterministic problems. Rather, we are regressing value functions discounted back at t=1 against the value of S_t^i. We are using our set of scenarios to build an approximation of the conditional expectation continuation value component. That is the key idea of the Longstaff and Schwartz method. Note that we only do so when stochasticity is involved, i.e. when we may invest in technology B.

We proceed like in the deterministic case by detailing the value function in t=1 for all the budget combinations.

$$\begin{aligned}
V_1(\bar{b}-2.I^A, S_1^i) &= \max_{x_1} \left\{ f_1(\bar{b}-2.I^A, 0, S_1^i) + e^{-r}.\mathbb{E}_1^Q[V_2(\bar{b}-2.I^A, \tilde{S}_2^i)] \right\} \\
&= \max_{x_1} \left\{ f_1(\bar{b}-2.I^A, 0, S_1^i) + e^{-r}.V_2(\bar{b}-2.I^A, S_2^i) \right\} \\
&= 0 \text{ with } x_1^*{=}0 \text{ and } \forall i. \\
V_1(\bar{b}-I^B, S_1^i) &= \max_{x_1} \left\{ f_1(\bar{b}-I^B, 0, S_1^i) + e^{-r}.\mathbb{E}_1^Q[V_2(\bar{b}-I^B, \tilde{S}_2^i)] \right\} \\
&= \max_{x_1} \left\{ f_1(\bar{b}-I^B, 0, S_1^i) + e^{-r}.V_2(\bar{b}-I^B, S_2^i) \right\} \\
&= 0 \text{ with } x_1^*{=}0 \text{ and } \forall i. \\
V_1(\bar{b}-I^A, S_1^i) &= \max_{x_1} \Big\{ f_1(\bar{b}-I^A, 0, S_1^i) + e^{-r}.\mathbb{E}_1^Q[V_2(\bar{b}-I^A, \tilde{S}_2^i)]; \\
&\qquad f_1(\bar{b}-I^A, I^A, S_1^i) + e^{-r}.\mathbb{E}_1^Q[V_2(\bar{b}-2.I^A, \tilde{S}_2^i)] \Big\} \\
&= \max_{x_1} \big\{ f_1(\bar{b}-I^A, 0, S_1^i) + e^{-r}.V_2(\bar{b}-I^A, S_2^i); \\
&\qquad f_1(\bar{b}-I^A, I^A, S_1^i) + e^{-r}.V_2(\bar{b}-2.I^A, S_2^i) \big\} \\
&= \max_{x_1} \left\{ 0 + e^{-r}.NPV_2^A; NPV_1^A + 0 \right\} \\
&= \max_{x_1} \left\{ 227; 250 \right\} \\
&= 250 \text{ with } x_1^*{=}I^A \text{ and } \forall i.
\end{aligned}$$

We move to the $b_1 = \bar{b}$ case.

$$\begin{aligned}
V_1(\bar{b}, S_1^i) &= \max_{x_1} \Big\{ f_1(\bar{b}, 0, S_1^i) + e^{-r}.\mathbb{E}_1^Q[V_2(\bar{b}, \tilde{S}_2^i)]; \\
&\qquad f_1(\bar{b}, I^A, S_1^i) + e^{-r}.\mathbb{E}_1^Q[V_2(\bar{b}-I^A, \tilde{S}_2^i)]; \\
&\qquad f_1(\bar{b}, I^B, S_1^i) + e^{-r}.\mathbb{E}_1^Q[V_2(\bar{b}-I^B, \tilde{S}_2^i)]; \\
&\qquad f_1(\bar{b}, 2.I^A, S_1^i) + e^{-r}.\mathbb{E}_1^Q[V_2(\bar{b}-2.I^A, \tilde{S}_2^i)] \Big\} \\
&= \max_{x_1} \Big\{ f_1(\bar{b}, 0, S_1^i) + e^{-r}.\mathbb{E}_1^Q[V_2(\bar{b}, \tilde{S}_2^i)]; \\
&\qquad f_1(\bar{b}, I^A, S_1^i) + e^{-r}.[V_2(\bar{b}-I^A, S_2^i)]; \\
&\qquad f_1(\bar{b}, I^B, S_1^i) + e^{-r}.[V_2(\bar{b}-I^B, S_2^i)]; \\
&\qquad f_1(\bar{b}, 2.I^A, S_1^i) + e^{-r}.[V_2(\bar{b}-2.I^A, S_2^i)] \big\}
\end{aligned}$$

In our illustrative case, only one investment decision is problematic (do not invest/wait at t=1 in blue) and we will approximate the expected continuation value by performing a linear regression of $e^{-r}.V_{2,i}(\bar{b})$ against a set of basis functions for this decision. The basis functions for the regression retained in this example are the first and second powers of the power price paths.

We consider the following regression model:

$$e^{-r}.\mathbb{E}_1^Q[V_2(\bar{b}, \tilde{S}_2^i)] \quad \approx \quad \phi_2(\bar{b}, S_2^i) = c_{0,1} + c_{1,1}.S_1^i + c_{2,1}.(S_1^i)^2 + e_i$$

Table 22 compiles data for the regression (dependent and independent variables). The linear regression yields the following[29]:

Table 22: Illustrative case - Sample OLS regression data

Path	$e^{-r}.V_{2,i}(b)$	S_1^i	$(S_1^i)^2$
1	455	53.29	2,840
2	635	54.05	2,922
3	462	54.24	2,942
4	887	53.20	2,831
5	455	53.81	2,896
6	697	54.69	2,991
7	455	53.04	2,813
8	624	53.88	2,903

$$e^{-r}.\mathbb{E}_1^Q[V_2(\bar{b}, \tilde{S}_2^i)] \quad \approx \quad \phi_2(\bar{b}, S_2^i) = 357,959 - 13,302(S_1^i) + 123.77(S_1^i)^2$$

Coming back to the value function, we replace the conditional expectation component by its approximation (in blue):

$$\begin{aligned}
V_1(\bar{b}, S_1^i) \quad \approx \quad & \max_{x_1} \{ f_1(\bar{b}, 0, S_1^i) + \phi_2(\bar{b}, S_2^i); \\
& f_1(\bar{b}, I^A, S_1^i) + e^{-r}.[V_2(\bar{b} - I^A, S_2^i)]; \\
& f_1(\bar{b}, I^B, S_1^i) + e^{-r}.[V_2(\bar{b} - I^B, S_2^i)]; \\
& f_1(\bar{b}, 2.I^A, S_1^i) + e^{-r}.[V_2(\bar{b} - 2.I^A, S_2^i)] \} \\
\approx \quad & \max_{x_1} \{ 0 + \phi_2(\bar{b}, S_2^i);\ NPV_1^A + e^{-r}.NPV_2^A; \\
& NPV_1^B + 0;\ 2.NPV_1^A + 0 \}
\end{aligned}$$

In table 23, we detail the investment alternatives at t=1 and highlight in bold the maximum value.

[29] To improve the quality of the linear regression and the computation speed in more complex cases, we may exclude paths favouring investments in technology A or waiting over investment in technology B for the linear regression estimation. We would therefore build on the moneyness criteria idea used for American option pricing in the Longstaff and Schwartz paper.

Table 23: Illustrative case - Decision nodes at t=1 and optimal decision for untapped budget

Path	$\phi_2(\bar{b}, S_2^i)$	$NPV_1^A + e^{-r}.NPV_2^A$	$NPV_1^{B,i}$	$2.NPV_1^A$	x_1^*
1	**573**	477	372	500	0
2	561	477	**598**	500	I^B
3	**580**	477	417	500	0
4	584	477	**865**	500	I^B
5	**549**	477	354	500	0
6	662	477	**674**	500	I^B
7	**608**	477	337	500	0
8	551	477	**597**	500	I^B
average	**584**	477	527	500	0

In tables 24 and 25, we summarize the value functions and optimal decisions for each budget level and each path at t=1.

Table 24: Illustrative case - Value function vs. budget level at t=1

Path	$b_1 = \bar{b} - 2.I^A$	$b_1 = \bar{b} - I^B$	$b_1 = \bar{b} - I^A$	$b_1 = \bar{b}$
1	0	0	250	573
2	0	0	250	598
3	0	0	250	580
4	0	0	250	865
5	0	0	250	549
6	0	0	250	674
7	0	0	250	608
8	0	0	250	597

Table 25: Illustrative case - Optimal decision vs. budget level at t=1

Path	$b_1 = \bar{b} - 2.I^A$	$b_1 = \bar{b} - I^B$	$b_1 = \bar{b} - I^A$	$b_1 = \bar{b}$
1	0	0	I^A	0
2	0	0	I^A	I^B
3	0	0	I^A	0
4	0	0	I^A	I^B
5	0	0	I^A	0
6	0	0	I^A	I^B
7	0	0	I^A	0
8	0	0	I^A	I^B

At t=0

Moving step back in time to t=0, the value function again takes the following form:

$$V_0(b_0, S_0^i) = \max_{x_0} \left\{ f_0(b_0, x_0, S_0^i) + e^{-r}.\mathbb{E}_0^Q[V_1(b_0 - x_0, \tilde{S}_1^i)] \right\} \ , \forall i.$$

At t=0, we only have one possible budget level, $\bar{b}$, the initial endowment.

$$\begin{aligned}
V_0(\bar{b}, S_0^i) &= \max_{x_0} \Big\{ f_0(\bar{b}, 0, S_0^i) + e^{-r}.\mathbb{E}_0^Q[V_1(\bar{b}, \tilde{S}_1^i)]; \\
&\quad f_0(\bar{b}, I^A, S_0^i) + e^{-r}.\mathbb{E}_0^Q[V_1(\bar{b} - I^A, \tilde{S}_1^i)]; \\
&\quad f_0(\bar{b}, I^B, S_0^i) + e^{-r}.\mathbb{E}_0^Q[V_1(\bar{b} - I^B, \tilde{S}_1^i)]; \\
&\quad f_0(\bar{b}, 2.I^A, S_0^i) + e^{-r}.\mathbb{E}_0^Q[V_1(\bar{b} - 2.I^A, \tilde{S}_1^i)] \Big\} \\
&= \max_{x_0} \Big\{ f_0(\bar{b}, 0, S_0^i) + e^{-r}.\mathbb{E}_0^Q[V_1(\bar{b}, S_1^i)]; \\
&\quad f_0(\bar{b}, I^A, S_0^i) + e^{-r}.V_1(\bar{b} - I^A, S_1^i); \\
&\quad f_0(\bar{b}, I^B, S_0^i) + e^{-r}.V_1(\bar{b} - I^B, S_1^i); \\
&\quad f_0(\bar{b}, 2.I^A, S_0^i) + e^{-r}.V_1(\bar{b} - 2.I^A, S_1^i) \Big\} \\
&= \max_{x_0} \Big\{ 0 + e^{-r}.\mathbb{E}_0^Q[V_1(\bar{b}, \tilde{S}_1^i)];\; NPV_0^A + e^{-r}.NPV_1^A; \\
&\quad NPV_0^{B,i} + 0;\; 2.NPV_0^A + 0 \Big\} \\
&= \max_{x_0} \Big\{ e^{-r}.\mathbb{E}_0^Q[V_1(\bar{b}, \tilde{S}_1^i)];\; 477;\; NPV_0^{B,i};\; 500 \Big\}
\end{aligned}$$

Now simply discounting all cash flows back to time t=0 and averaging over the eight sample paths, we get an estimate of $e^{-r}.\mathbb{E}_0^Q[V_1(\bar{b}, \tilde{S}_1^i)]$ [30]. We obtain in table 26 the maximum value and associated optimal decisions:

Table 26: Illustrative case - Decision nodes at t=0 and optimal decision for initial budget

Path	$e^{-r}.\mathbb{E}_0^Q[V_1(\bar{b}, \tilde{S}_1^i)]$	$NPV_0^A + e^{-r}.NPV_1^A$	$NPV_0^{B,i}$	$2.NPV_0^A$	x_0^*
1	**521**	477	278	500	0
2	**544**	477	495	500	0
3	**527**	477	321	500	0
4	**786**	477	751	500	0
5	500	477	261	**500**	$2.I^A$
6	**613**	477	573	500	0
7	**553**	477	241	500	0
8	**543**	477	502	500	0
average	**573**	477	436	500	0

The optimal path

The optimal path represents the decisions that must be taken sequentially in order to realize that maximum average value. At t=0, we find that the optimal decision is to wait ($\hat{x}_0^*$=0) by looking at the column average in table

[30] The results are identical with a linear regression in which the dependent variable is $e^{-r}.\mathbb{E}_0^Q[V_1(\bar{b}, \tilde{S}_1^i)]$ and the independent variables are the first and second power of the known price of power at t=0. Unsurprisingly, only the intercept, equal to the average of discounted $V_1(\bar{b})$, is non null.

26. Based on this optimal decision to wait, we move forward in the tree and look for the permissible decision that maximize $V_1(\bar{b})$ on average in table 23. Again the approximated optimal decision is to wait ($\hat{x}_1^*$=0). Knowing that, we look for the permissible decision that maximize $V_2(\bar{b})$ on average in table 19 and find that the approximated optimal decision is to invest in one unit of technology B ($\hat{x}_2^*$=I^B).

The approximated optimal path ($\hat{x}_0^*$=0; $\hat{x}_1^*$=0; $\hat{x}_2^*$=I^B) is to wait two periods and then invest in one unit of technology B. It is important to note that is not the optimal decision for all the paths generated but an approximation of the optimal decision based on a sample of i paths. In particular, looking back in tables 26, 23 and 19, we find that the optimal decisions coincides in only one of the eight paths we generated - the others paths favour investment in technology B as early as in t=1 or investment in two units of technology A now or in t=2 [31]. But since we have no knowledge of the price paths, the approximated optimal path is the best proxy we have for decision-making.

[31] Note that this is not exactly a deterministic decision framework since we resort to the OLS estimation of continuation values but this should give the general idea.

.3 LSM matrices

MAX stands for the maximum value to be found within brackets, while ARGMAX reports the associated maximizing decision.

Table 27: Appendix - $\mathcal{M}R_t$ - Immediate reward component of the value function in t

$$\begin{pmatrix} f_t(\bar{b}-I^N,0,S_t^1) & ... & f_t(\bar{b}-I^N,I^N,S_t^1) & ... & f_t(\bar{b}-I^W,I^G,S_t^1) & ... & f_t(\bar{b},0,S_t^1) & ... & f_t(\bar{b},I^N,S_t^1) \\ f_t(\bar{b}-I^N,0,S_t^2) & ... & f_t(\bar{b}-I^N,I^N,S_t^2) & ... & f_t(\bar{b}-I^W,I^G,S_t^2) & ... & f_t(\bar{b},0,S_t^2) & ... & f_t(\bar{b},I^N,S_t^2) \\ ... & ... & ... & ... & ... & ... & ... & ... & ... \\ f_t(\bar{b}-I^N,0,S_t^i) & ... & f_t(\bar{b}-I^N,I^N,S_t^i) & ... & f_t(\bar{b}-I^W,I^G,S_t^i) & ... & f_t(\bar{b},0,S_t^i) & ... & f_t(\bar{b},I^N,S_t^i) \\ ... & ... & ... & ... & ... & ... & ... & ... & ... \\ f_t(\bar{b}-I^N,0,S_t^\Gamma) & ... & f_t(\bar{b}-I^N,I^N,S_t^\Gamma) & ... & f_t(\bar{b}-I^W,I^G,S_t^\Gamma) & ... & f_t(\bar{b},0,S_t^\Gamma) & ... & f_t(\bar{b},I^N,S_t^\Gamma) \end{pmatrix}$$

$$= \begin{pmatrix} 0 & ... & -\infty & ... & NPV_t^{G,1} & ... & 0 & ... & NPV_t^{N,1} \\ 0 & ... & -\infty & ... & NPV_t^{G,2} & ... & 0 & ... & NPV_t^{N,2} \\ ... & ... & ... & ... & ... & ... & ... & ... & ... \\ 0 & ... & -\infty & ... & NPV_t^{G,i} & ... & 0 & ... & NPV_t^{N,i} \\ ... & ... & ... & ... & ... & ... & ... & ... & ... \\ 0 & ... & -\infty & ... & NPV_t^{G,\Gamma} & ... & 0 & ... & NPV_t^{N,\Gamma} \end{pmatrix}$$

Table 28: Appendix - $\mathcal{M}C_t$ - Continuation value component of the value function in t

$$\begin{pmatrix} e^{-r}.\mathbb{E}_t^Q[V_{t+1}(\bar{b}-I^N,\tilde{S}_{t+1}^1)] & ... & e^{-r}.\mathbb{E}_t^Q[V_{t+1}(\bar{b}-I^N-I^N,\tilde{S}_{t+1}^1)] & ... & e^{-r}.\mathbb{E}_t^Q[V_{t+1}(\bar{b}-I^W-I^G,\tilde{S}_{t+1}^1)] & ... & e^{-r}.\mathbb{E}_t^Q[V_{t+1}(\bar{b},\tilde{S}_{t+1}^1)] & ... & e^{-r}.\mathbb{E}_t^Q[V_{t+1}(\bar{b}-I^N,\tilde{S}_{t+1}^1)] \\ e^{-r}.\mathbb{E}_t^Q[V_{t+1}(\bar{b}-I^N,\tilde{S}_{t+1}^2)] & ... & e^{-r}.\mathbb{E}_t^Q[V_{t+1}(\bar{b}-I^N-I^N,\tilde{S}_{t+1}^2)] & ... & e^{-r}.\mathbb{E}_t^Q[V_{t+1}(\bar{b}-I^W-I^G,\tilde{S}_{t+1}^2)] & ... & e^{-r}.\mathbb{E}_t^Q[V_{t+1}(\bar{b},\tilde{S}_{t+1}^2)] & ... & e^{-r}.\mathbb{E}_t^Q[V_{t+1}(\bar{b}-I^N,\tilde{S}_{t+1}^2)] \\ ... & ... & ... & ... & ... & ... & ... & ... & ... \\ e^{-r}.\mathbb{E}_t^Q[V_{t+1}(\bar{b}-I^N,\tilde{S}_{t+1}^i)] & ... & e^{-r}.\mathbb{E}_t^Q[V_{t+1}(\bar{b}-I^N-I^N,\tilde{S}_{t+1}^i)] & ... & e^{-r}.\mathbb{E}_t^Q[V_{t+1}(\bar{b}-I^W-I^G,\tilde{S}_{t+1}^i)] & ... & e^{-r}.\mathbb{E}_t^Q[V_{t+1}(\bar{b},\tilde{S}_{t+1}^i)] & ... & e^{-r}.\mathbb{E}_t^Q[V_{t+1}(\bar{b}-I^N,\tilde{S}_{t+1}^i)] \\ ... & ... & ... & ... & ... & ... & ... & ... & ... \\ e^{-r}.\mathbb{E}_t^Q[V_{t+1}(\bar{b}-I^N,\tilde{S}_{t+1}^\Gamma)] & ... & e^{-r}.\mathbb{E}_t^Q[V_{t+1}(\bar{b}-I^N-I^N,\tilde{S}_{t+1}^\Gamma)] & ... & e^{-r}.\mathbb{E}_t^Q[V_{t+1}(\bar{b}-I^W-I^G,\tilde{S}_{t+1}^\Gamma)] & ... & e^{-r}.\mathbb{E}_t^Q[V_{t+1}(\bar{b},\tilde{S}_{t+1}^\Gamma)] & ... & e^{-r}.\mathbb{E}_t^Q[V_{t+1}(\bar{b}-I^N,\tilde{S}_{t+1}^\Gamma)] \end{pmatrix}$$

$$= \begin{pmatrix} \phi_{t+1}(\bar{b}-I^N,S_{t+1}^1) & ... & -\infty & ... & \phi_{t+1}(\bar{b}-I^W-I^G,S_{t+1}^1) & ... & \phi_{t+1}(\bar{b},S_{t+1}^1) & ... & 0 \\ \phi_{t+1}(\bar{b}-I^N,S_{t+1}^2) & ... & -\infty & ... & \phi_{t+1}(\bar{b}-I^W-I^G,S_{t+1}^2) & ... & \phi_{t+1}(\bar{b},S_{t+1}^2) & ... & 0 \\ ... & ... & ... & ... & ... & ... & ... & ... & ... \\ \phi_{t+1}(\bar{b}-I^N,S_{t+1}^i) & ... & -\infty & ... & \phi_{t+1}(\bar{b}-I^W-I^G,S_{t+1}^i) & ... & \phi_{t+1}(\bar{b},S_{t+1}^i) & ... & 0 \\ ... & ... & ... & ... & ... & ... & ... & ... & ... \\ \phi_{t+1}(\bar{b}-I^N,S_{t+1}^\Gamma) & ... & -\infty & ... & \phi_{t+1}(\bar{b}-I^W-I^G,S_{t+1}^\Gamma) & ... & \phi_{t+1}(\bar{b},S_{t+1}^\Gamma) & ... & 0 \end{pmatrix}$$

Table 29: Appendix - $\mathcal{M}V_t$ and $\mathcal{M}x_t^*$ - Value function and associated optimal decision in t

$$\begin{pmatrix}
\max_{x_t}[\phi_{t+1}(\bar{b}-I^N,S^1_{t+1});...;-\infty] & ... & \max_{x_t}[\phi_{t+1}(\bar{b}-I^W,S^1_{t+1});...;-\infty] & \max_{x_t}[\phi_{t+1}(\bar{b},S^1_{t+1});...;NPV_t^{N,1}] \\
\max_{x_t}[\phi_{t+1}(\bar{b}-I^N,S^2_{t+1});...;-\infty] & ... & \max_{x_t}[\phi_{t+1}(\bar{b}-I^W,S^2_{t+1});...;-\infty] & \max_{x_t}[\phi_{t+1}(\bar{b},S^2_{t+1});...;NPV_t^{N,2}] \\
... & ... & ... & ... \\
\max_{x_t}[\phi_{t+1}(\bar{b}-I^N,S^i_{t+1});...;-\infty] & ... & \max_{x_t}[\phi_{t+1}(\bar{b}-I^W,S^i_{t+1});...;-\infty] & \max_{x_t}[\phi_{t+1}(\bar{b},S^i_{t+1});...;NPV_t^{N,i}] \\
... & ... & ... & ... \\
\max_{x_t}[\phi_{t+1}(\bar{b}-I^N,S^\Gamma_{t+1});...;-\infty] & ... & \max_{x_t}[\phi_{t+1}(\bar{b}-I^W,S^\Gamma_{t+1});...;-\infty] & \max_{x_t}[\phi_{t+1}(\bar{b},S^\Gamma_{t+1});...;NPV_t^{N,\Gamma}]
\end{pmatrix}$$

$$\begin{pmatrix}
\text{argmax}_{x_t}[\phi_{t+1}(\bar{b}-I^N,S^1_{t+1});...;-\infty] & ... & \text{argmax}_{x_t}[\phi_{t+1}(\bar{b}-I^W,S^1_{t+1});...;-\infty] & \text{argmax}_{x_t}[\phi_{t+1}(\bar{b},S^1_{t+1});...;NPV_t^{N,1}] \\
\text{argmax}_{x_t}[\phi_{t+1}(\bar{b}-I^N,S^2_{t+1});...;-\infty] & ... & \text{argmax}_{x_t}[\phi_{t+1}(\bar{b}-I^W,S^2_{t+1});...;-\infty] & \text{argmax}_{x_t}[\phi_{t+1}(\bar{b},S^2_{t+1});...;NPV_t^{N,2}] \\
... & ... & ... & ... \\
\text{argmax}_{x_t}[\phi_{t+1}(\bar{b}-I^N,S^i_{t+1});...;-\infty] & ... & \text{argmax}_{x_t}[\phi_{t+1}(\bar{b}-I^W,S^i_{t+1});...;-\infty] & \text{argmax}_{x_t}[\phi_{t+1}(\bar{b},S^i_{t+1});...;NPV_t^{N,i}] \\
... & ... & ... & ... \\
\text{argmax}_{x_t}[\phi_{t+1}(\bar{b}-I^N,S^\Gamma_{t+1});...;-\infty] & ... & \text{argmax}_{x_t}[\phi_{t+1}(\bar{b}-I^W,S^\Gamma_{t+1});...;-\infty] & \text{argmax}_{x_t}[\phi_{t+1}(\bar{b},S^\Gamma_{t+1});...;NPV_t^{N,\Gamma}]
\end{pmatrix}$$

.4 MATLAB code

```
%% INPUT
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
% STEP 1.1 - variables initialization
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
%
%
%M-File to initialize variables
    clear memory;
% GENERAL PARAMETERS
    info.years=79; %nÂ° of years of simulation
    info.simul=200; %nÂ° of Montecarlo simulations (10,000 by default)
    info.step=12;   %nÂ° of interval in which time (year) is divided
                    %MONTHS (12) and DAYS (365)
    info.rp=0; % risk premium (risk-neutral parameter fitting)
    info.r=0.06+info.rp; %discount rate
    info.nTrials=info.simul;% number of trial paths generated
    info.nPeriods=info.step*info.years; % nb of simulated observations
    info.dt=1/info.step; % Else one day is as volatile as a year
    info.regressor='spot'; %Set at 'spot' to regress against spot
                           %prices, otherwise against forward values
    info.dailyprices='notdaily'; %Set at 'daily' to compute annual
                                 %profits based on daily prices,
                                 %otherwise average monthly prices
    info.ner='no'; %'NER2Y'NER for two first years
                   %'NER3Y'NER for two three years
    info.fit='stop'; % stop the FITs tarifs in 2012
% b - BUDGET CONSTRAINT
    b.bbar=5000; % Initial budget (in Millions of EUR)
% W - WIND POWER PLANT (OFFSHORE)
    W.build=1;  % construction time (in years)
    W.life=25; % lifetime (in years)
    W.capacity=300;% Plant capacity in MW
    W.availability=0.43;% Plant availibility
    W.output=24*W.capacity*W.availability; % power produced (in MWh)
                                           % on a daily basis
    W.inves=1022; % initial investment outlay (in EUR million)
                  % incurred at decision
    W.om=31.64; % O&M in EUR/MWh (from NEA/OECD/IEA, 2010).
    W.forward=0; % percentage of the production sold through
                 % forward transactions
%K - PULVERIZED COAL-FIRED POWER PLANT
    K.build=4;  %construction time (in years)
    K.life=40; %lifetime (in years)
    K.capacity=800;%Plant capacity in MW
    K.availability=0.3;%Plant availibility
    K.output=24*K.capacity*K.availability; %power produced (in MWh) on
                                           %a daily basis
    K.te=0.46; %thermal efficiency
    K.ef=0.728; %emission factor for the power plant
    K.cf=1/6.971;%conversion factor from tons to MWh (source: REUTERS)
```

```
    K.inves=1166;%initial investment outlay (in EUR million) incurred
                 %at decision
    K.om=8.67; % O&M in EUR/MWh (from NEA/OECD/IEA, 2010).
    K.CO2=K.output*365*K.ef*K.life/1000000; %Locked-in CO2 emissions
    K.forward=[0;0]; %weight of the production sold/bought through
                     %forward transactions
%I - IGCC (PC+CSS in modified version)
    I.build=4;  %construction time (in years) OK
    I.life=40; %lifetime (in years) OK
    I.capacity=740;%Plant capacity in MW OK
    I.availability=0.3;%Plant availibility OK
    I.output=24*I.capacity*I.availability; %power produced (in MWh)
                                           %on a daily basis
    I.te=0.38; %thermal efficiency OK
    I.ef=0.0728; %emission factor for the power plant %%%% Good ref?
    I.cf=1/6.971;%conversion factor from tons to MWh (source: REUTERS)
    I.inves=1789;%initial investment outlay (in EUR million) incurred
                 %at decision OK
    I.om=13.6748; % O&M in EUR/MWh (from NEA/OECD/IEA, 2010). OK
    I.CO2=I.output*365*I.ef*I.life/1000000; %Locked-in CO2 emissions
    I.forward=[0;0]; %weight of the production sold/bought
                     %through forward transactions
%G - CCGT POWER PLANT
    G.build=3;  %construction time (in years) => 2 years is better
    G.life=30; %lifetime (in years)
    G.capacity=800;%Plant capacity in MW
    G.availability=0.3;%Plant availibility
    G.output=24*G.capacity*G.availability; %power produced (in MWh)
                                           %on a daily basis
    G.te=0.60; %thermal efficiency
    G.ef=0.353; %emission factor for the power plant
    G.cf=0.2930711111; %conversion factor from MMBTU to MWh
                       %(source: IEA conversion table)
    G.inves=628; %initial investment outlay (in EUR million) incurred
                %at decision
    G.om=4.60; % O&M in EUR/MWh (from NEA/OECD/IEA, 2010). OK
    G.CO2=G.output*365*G.ef*G.life/1000000; %Locked-in CO2 emissions
    G.forward=[0;0]; %weight of the production sold/bought through
                     %forward transactions
%N - NUCLEAR POWER PLANT
    N.build=7;  %construction time (in years)
    N.life=60; %lifetime (in years)
    N.capacity=1630;%Plant capacity in MW
    N.availability=0.80;%Plant availibility
    N.output=24*N.capacity*N.availability; %power produced (in MWh)
                                           %on a daily basis
    N.te=0.36; %thermal efficiency (any use?)
    N.inves=4998; %initial investment outlay (in EUR million) incurred
                  %at decision
    N.fuelcost=(7+2.33)*0.684; %initial param in EUR/MWh (front-end
                               %+ back-end converted in EUR) OK
    N.om=10.94; % O&M in EUR/MWh (from NEA/OECD/IEA, 2010). OK
    N.forward=0; %weight of the production sold through forward
                 %transactions
```

```
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
% STEP 1.2 - specifying the elements for multidimensional HWV
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
%
%
    price.correlation=[1 0.5301 0.5561; 0.5301 1 0.9837; ...
        0.5561 0.9837 1];
    price.nVariables=3;
    price.speed=[2.4471 0.9125 0.8921]; % ADJUSTED PARAM
    price.speeddiag=diag(price.speed'); % is a NVARSbyNVARS matrix
        price.level=[0.0349 0.0018 0.0020]';
    price.sigma=[0.19 0.0321 0.0295]; % ADJUSTED PARAM TO BE CONSISTENT
                                  % WITH ADJUSTMENT TO THETA
    price.sigmadiag=diag(price.sigma'); % is a NVARSbyBROWNS matrix
    price.startstate=[0.1645 -0.0532 -0.0292]; % starting value
                                               % for MR sto pro
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
% STEP 1.3 - Elements for the Matrix for trends
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
%
%
  price.levelCO2=2.69;
  price.slopeCO2=0.025;
  price.levelpeak=4.25;
  price.slopepeak=0.008;
  price.levelbase=3.98;
  price.slopebase=0.006;
    price.testoncarbon='off';%'intertemporalban'indicates the EC
                    % ban intertemporal flex between phase II and III,
    %'killets2020' indictes EU ETS policy is interrupted 2021 onwards
    price.levelCO2phase2=2.5992; % 3.8 equivalent to EUR 45/t
                       %and 3.4 equiv. to EUR 30/t and 2.99 for EUR 20
    price.slopeCO2phase2=-1.5;
    price.levelCO2phase3=3.3; % 3.8 equivalent to EUR 45/t
                       %and 3.4 equiv. to EUR 30/t and 2.99 for EUR 20
    price.slopeCO2phase3=0.025;
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
% STEP 1.4 - Other inputs (Fuels)
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
%
%
price.reference='static'; % Data stem from WEO09 for 'WEO09',
          %'static' @EUR 40/t for coal and EUR X/MMBTu else from WEO08
switch price.reference
    case 'static'
        load COALstatic
        load NATGAS
        price.GAS = repmat(GasEURperMMBTU, [1 1 info.nTrials]);
        price.COAL = repmat(CoalEURperTon, [1 1 info.nTrials]);
        clear GasEURperMMBTU
        clear CoalEURperTon
    case 'WEO09'
        load COAL09
        load NATGAS
```

```
        price.GAS = repmat(GasEURperMMBTU, [1 1 info.nTrials]);
        price.COAL = repmat(CoalEURperTon, [1 1 info.nTrials]);
        clear GasEURperMMBTU
        clear CoalEURperTon
    otherwise
        load COAL
        load NATGAS
        price.GAS = repmat(GasEURperMMBTU, [1 1 info.nTrials]);
        price.COAL = repmat(CoalEURperTon, [1 1 info.nTrials]);
        clear GasEURperMMBTU
        clear CoalEURperTon
end
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
% STEP 1.5 - Policy elements from the EU ETS
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
%
%
%%%%%%%%%%%%%%%% EU ETS EXISTENCE %%%%%%%%%%%%%%%%
    euets.endyear=30;% Year the EU ETS policy ends (in years)
    euets.changetotaxyear=30;% Year the EU ETS policy is replaced by
                             % a tax (in years)
    euets.changetotaxlevel=100; %Tax level instead of an EU ETS
%%%%%%%%%%%%%%%% CARBON PRICE GROWTH RATE %%%%%%%%%%%%%%%%
    euets.growth2=0.025; % exp? growth rate over phase II
                         % of the EU ETS (2008-2012)
    euets.growth3=0.025; % exp? growth rate over phase III
                         % of the EU ETS (2013-2020)
    euets.growth4=0.025; % exp? growth rate over phase IV
                         % of the EU ETS (2021-...)
%%%%%%%%%%%%%%%% INTERTEMPORAL FLEX. %%%%%%%%%%%%%%%%
    euets.banking2to3=1.0; % Percentage of banking from
                           % phase II to phase III
    euets.banking3to4=1.0; % Percentage of banking from
                           % phase III to phase IV
    euets.borrowing3to2=1.0; % Percentage of borrowing
                             % from phase III to phase II
    euets.borrowing4to3=1.0; % Percentage of borrowing
                             % from phase IV to phase III
%%%%%%%%%%%%%%%% CARBON TAX %%%%%%%%%%%%%%%%
    euets.offset2=0.134; % Percentage of compliance that can be
                         % achieved with offsets in phase II
    euets.offset3=0.10; % Percentage of compliance that can be
                        % achieved with offsets in phase III
    euets.offset4=0.05; % Percentage of compliance that can be
                        % achieved with offsets in phase IV
    euets.offsetdisc2=0.2; % Offset discount to EUAs in phase II
    euets.offsetdisc3=0.3; % Offset discount to EUAs in phase III
    euets.offsetdisc4=0.3; % Offset discount to EUAs in phase IV
%%%%%%%%%%%%%%%% PHASED-IN AUCTIONING POWER SECTOR PHASE III %%%%%%%%%
    euets.auctionstart3=1; % Percentage of allowances auctioned
                           % in 2013 for the power sector
    euets.auctionrate3=0; % Annual increase of the percentage
                          % of auctioning in phase III
%%%%%%%%%%%%%%%% NER %%%%%%%%%%%%%%%%
```

```
    euets.ner2=0.01; % NER for phase II
                     % (% or Mt - still to be specified)
    euets.ner3=0.05; % NER for phase III
                     % (% or Mt - still to be specified)
%%%%%%%%%%%%%%%% PRICE CONTROL %%%%%%%%%%%%%%%%%
    euets.lenghtphase2=2;
    euets.lenghtphase3=8;
    euets.lenghtphase4=69;
    euets.pricecap2=inf; % Price cap over phase II of the EU ETS
    euets.pricecap3=inf; % Price cap over phase III of the EU ETS
    euets.pricecap4=inf; % Price cap over phase IV of the EU ETS
    euets.pricefloor2=0; % Price floor over phase II of the EU ETS
    euets.pricefloor3=0; % Price floor over phase III of the EU ETS
    euets.pricefloor4=0; % Price floor over phase IV of the EU ETS
%%%%%%%%%%%%%%%% TAX AND AUCTIONING REVENUE USE %%%%%%%%%%
    euets.fit1lenght=10;
    euets.fit2lenght=10;
    euets.fit1level=130;
    euets.fit2level=64;
    euets.fit2=120; %FIT for renewables in phase II
    % (in EUR/MWh baseload)
    euets.fit3=120; %FIT for renewables in phase III
    % (in EUR/MWh baseload)
    euets.fit4=120; %FIT for renewables in phase IV
    % (in EUR/MWh baseload)
    euets.ccs=0; % CCS subvention over phase II
function [results, price, profit, npv, m] = ...
    greenfield (info, b, W, K, I, G, N, price, euets)
tic % start time counting
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
% STEP 2.1 - Simulation of detrend (by solution rather than by Euler)
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
%
%%
    obj=hwv(price.speeddiag, price.level, price.sigmadiag, ...
        'Correlation', price.correlation, ...
        'StartState', price.startstate');
    randn('state', 100) % generate a 100x100 draw from a distrib
    [price.S,price.T]=obj.simBySolution(info.nPeriods, ...
        'DeltaTime', info.dt, 'nTrials', info.nTrials);
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
% STEP 2.2 - Matrix for trends
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
%
%%
switch price.testoncarbon
    case 'intertemporalban'
    price.lntrendCO2 = [(price.levelCO2phase2 + ...
        (price.slopeCO2phase2/info.step)*(1:24)');...
        (price.levelCO2phase3 + ...
        (price.slopeCO2phase3/info.step)*(25:info.nPeriods+1)')];
    price.lntrend = [(price.lntrendCO2) (price.levelpeak + ...
        (price.slopepeak/info.step)*(1:info.nPeriods+1)') ...
        (price.levelbase + ...
```

```
        (price.slopebase/info.step)*(1:info.nPeriods+1)')];
    price.lntrend = repmat(price.lntrend, [1 1 info.nTrials]);
    case 'killets2020'
    price.lntrendCO2 = [(price.levelCO2 + ...
    (price.slopeCO2/info.step)*(1:120)');(0.*(121:info.nPeriods+1)')];
    price.lntrend = [(price.lntrendCO2) ...
        (price.levelpeak + ...
        (price.slopepeak/info.step)*(1:info.nPeriods+1)') ...
        (price.levelbase + ...
        (price.slopebase/info.step)*(1:info.nPeriods+1)')];
    price.lntrend = repmat(price.lntrend, [1 1 info.nTrials]);
    otherwise
    price.lntrend = [(price.levelCO2 + ...
        (price.slopeCO2/info.step)*(1:info.nPeriods+1)') ...
        (price.levelpeak + ...
        (price.slopepeak/info.step)*(1:info.nPeriods+1)') ...
        (price.levelbase + ...
        (price.slopebase/info.step)*(1:info.nPeriods+1)')];
    price.lntrend = repmat(price.lntrend, [1 1 info.nTrials]);
end
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
% STEP 2.3 - Evaluating spot prices
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
%
%%
    price.spot=exp(price.lntrend+price.S);
    price.spotcarbon=permute(price.spot, [1 3 2]);
    price.spotcarbon=price.spotcarbon(:,:,1);
    price.spotpeak=permute(price.spot, [1 3 2]);
    price.spotpeak=price.spotpeak(:,:,2);
    price.spotbase=permute(price.spot, [1 3 2]);
    price.spotbase=price.spotbase(:,:,3);
%
% Average annual spot price
%
    Y=ones(1,3,info.nTrials);
    for i=1:info.years
        X=mean(price.spot(((12*i)-11):(12*i),:,:));
        Y=[Y;X];
    end
    price.avgspot=Y(2:end,:,:); %AVERAGE SPOT PRICE FOR THE YEAR

% Sum of daily spot prices over the number of years => SPOT only
%
    Y=ones(1,3,info.nTrials);
    for i=1:info.years
        X=sum(price.spot(((info.step*i)-(info.step-1)):...
            (info.step*i),:,:));
        Y=[Y;X];
    end
    price.sumspot=Y(2:end,:,:); % sUM OF DAILY SPOT PRICE FOR THE YEAR

 %% Add the possibility of price control measures
 % FLOOR - CAP - TUNNEL
```

```
 % populate, dimension it like carbon price
    euets.pricecap=[ones(euets.lenghtphase2,1).*euets.pricecap2; ...
    ones(euets.lenghtphase3,1).*euets.pricecap3; ...
    ones(euets.lenghtphase4,1).*euets.pricecap4];
    euets.pricefloor=[ones(euets.lenghtphase2,1).*euets.pricefloor2; ...
    ones(euets.lenghtphase3,1).*euets.pricefloor3; ...
    ones(euets.lenghtphase4,1).*euets.pricefloor4];
 % for all simulations
    Y=ones(info.years,info.nTrials);
    for j=1:info.nTrials
            X=min([euets.pricecap max([price.avgspot(:,1,j) euets.pricefloor],[],2)],
            Y=[Y X];
    end
    Y=Y(:,((info.nTrials+1):info.nTrials*2));
    Y=reshape(Y,[1, size(Y)]);
    Y=permute(Y, [2 1 3]);
    price.avgspot(:,1,:)=Y;
    % plot(squeeze(price.avgspot(:,1,:)))
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
% STEP 2.4 - Evaluating forward prices
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
%DISCONTINUED SECTION
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
% STEP 2.5 - Generate Annual Cash Flows Components
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
%DISCONTINUED SECTION
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
% STEP 2.6 - Generate Annual Cash Flows
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
%
%%
 switch info.dailyprices
     case 'daily'
        % for CCGT:
            profit.PiG=(G.output).*(price.sumspot(:,2,:)-...
                info.step.*(G.cf/G.te).*(price.GAS)-...
                (G.ef).*(price.sumspot(:,1,:))-info.step.*G.om);
        % for PC
            profit.PiK=(K.output).*(price.sumspot(:,2,:)-...
                info.step.*(K.cf/K.te).*(price.COAL)-...
                (K.ef).*(price.sumspot(:,1,:))-info.step.*K.om);
        % for IGCC
            profit.PiI=(I.output).*(price.sumspot(:,2,:)-...
                info.step.*(I.cf/I.te).*(price.COAL)-...
                (I.ef).*(price.sumspot(:,1,:))-info.step.*I.om);
        % for Nuke
            profit.PiN=(N.output).*(price.sumspot(:,3,:)-...
                info.step.*N.fuelcost-info.step.*N.om); %baseload
        % for the wind power plant (FITs taken into account later
        % when calculating NPVs)
            profit.PiW=(W.output).*(price.sumspot(:,3,:)-...
                info.step.*W.om); %, calculation is different
            % since not dependent on contemporaneous prices but
            % commissioning of the plant: 10Y@130, 10Y@64 and
```

```
        % contemporaneous baseload prices
        % (what this equation actually shows).
otherwise
    switch info.ner
        case 'NER2Y'
        price.avgspotG=price.avgspot;
        price.avgspotK=price.avgspot;
        price.avgspotI=price.avgspot;
        price.avgspotG(1,1,:)=0;
        price.avgspotG(2,1,:)=0;
        price.avgspotG(3,1,:)=0;
        price.avgspotG(4,1,:)=0;
        price.avgspotG(5,1,:)=0;
        price.avgspotG(6,1,:)=0;
        price.avgspotK(1,1,:)=0;
        price.avgspotK(2,1,:)=0;
        price.avgspotK(3,1,:)=0;
        price.avgspotK(4,1,:)=0;
        price.avgspotK(5,1,:)=0;
        price.avgspotK(6,1,:)=0;
        price.avgspotK(7,1,:)=0;
        price.avgspotI(1,1,:)=0;
        price.avgspotI(2,1,:)=0;
        price.avgspotI(3,1,:)=0;
        price.avgspotI(4,1,:)=0;
        price.avgspotI(5,1,:)=0;
        price.avgspotI(6,1,:)=0;
        price.avgspotI(7,1,:)=0;
    % for CCGT:
        profit.PiG=(G.output*365).*(price.avgspot(:,2,:)-...
            ((G.cf/G.te).*price.GAS)-...
            (G.ef).*(price.avgspotG(:,1,:))-G.om);
    % for PC
        profit.PiK=(K.output*365).*(price.avgspot(:,2,:)-...
            ((K.cf/K.te).*price.COAL)-...
            (K.ef).*(price.avgspotK(:,1,:))-K.om);
    % for IGCC
        profit.PiI=(I.output*365).*(price.avgspot(:,2,:)-...
            ((I.cf/I.te).*price.COAL)-...
            (I.ef).*(price.avgspotI(:,1,:))-I.om);
    % for Nuke
        profit.PiN=(N.output*365).*(price.avgspot(:,3,:)-...
            N.fuelcost-N.om); % use baseload power
    % for the wind power plant (FITs taken into account later)
        profit.PiW=(W.output*365).*(price.avgspot(:,3,:)-W.om);
        % calculation is different since not dependent on
        % contemporaneous prices but commissioning of the plant:
        % 10Y@130, 10Y@64
        % and contemporaneous baseload prices
        % (what this equation actually shows).
    case 'NER3Y'
        price.avgspotG=price.avgspot;
        price.avgspotK=price.avgspot;
        price.avgspotI=price.avgspot;
```

```
    price.avgspotG(1,1,:)=0;
    price.avgspotG(2,1,:)=0;
    price.avgspotG(3,1,:)=0;
    price.avgspotG(4,1,:)=0;
    price.avgspotG(5,1,:)=0;
    price.avgspotG(6,1,:)=0;
    price.avgspotG(7,1,:)=0;
    price.avgspotK(1,1,:)=0;
    price.avgspotK(2,1,:)=0;
    price.avgspotK(3,1,:)=0;
    price.avgspotK(4,1,:)=0;
    price.avgspotK(5,1,:)=0;
    price.avgspotK(6,1,:)=0;
    price.avgspotK(7,1,:)=0;
    price.avgspotK(8,1,:)=0;
    price.avgspotI(1,1,:)=0;
    price.avgspotI(2,1,:)=0;
    price.avgspotI(3,1,:)=0;
    price.avgspotI(4,1,:)=0;
    price.avgspotI(5,1,:)=0;
    price.avgspotI(6,1,:)=0;
    price.avgspotI(7,1,:)=0;
    price.avgspotI(8,1,:)=0;
% for CCGT:
    profit.PiG=(G.output*365).*(price.avgspot(:,2,:)-...
        ((G.cf/G.te).*price.GAS)-...
        (G.ef).*(price.avgspotG(:,1,:))-G.om);
% for PC
    profit.PiK=(K.output*365).*(price.avgspot(:,2,:)-...
        ((K.cf/K.te).*price.COAL)-...
        (K.ef).*(price.avgspotK(:,1,:))-K.om);
% for IGCC
    profit.PiI=(I.output*365).*(price.avgspot(:,2,:)-...
        ((I.cf/I.te).*price.COAL)-...
        (I.ef).*(price.avgspotI(:,1,:))-I.om);
% for Nuke
    profit.PiN=(N.output*365).*(price.avgspot(:,3,:)-...
        N.fuelcost-N.om); % use baseload power
% for the wind power plant (FITs taken into account later)
    profit.PiW=(W.output*365).*(price.avgspot(:,3,:)-W.om);
    % calculation is different since not dependent on
    % contemporaneous prices but commissioning of the plant:
    % 10Y@130, 10Y@64
    % and contemporaneous baseload prices
    % (what this equation actually shows).
     otherwise
% for CCGT:
    profit.PiG=(G.output*365).*(price.avgspot(:,2,:)-...
        ((G.cf/G.te).*price.GAS)-...
        (G.ef).*(price.avgspot(:,1,:))-G.om);
% for PC
    profit.PiK=(K.output*365).*(price.avgspot(:,2,:)-...
        ((K.cf/K.te).*price.COAL)-...
        (K.ef).*(price.avgspot(:,1,:))-K.om);
```

```
        % for IGC
            profit.PiI=(I.output*365).*(price.avgspot(:,2,:)-...
                ((I.cf/I.te).*price.COAL)-...
                (I.ef).*(price.avgspot(:,1,:))-I.om);
        % for Nuke
            profit.PiN=(N.output*365).*(price.avgspot(:,3,:)-...
                N.fuelcost-N.om); % use baseload power
        % for the wind power plant (FITs taken into account later)
            profit.PiW=(W.output*365).*(price.avgspot(:,3,:)-W.om);
            % calculation is different since not dependent on
            % contemporaneous prices but commissioning of the plant:
            % 10Y@130, 10Y@64
            % and contemporaneous baseload prices
            % (what this equation actually shows).
         end
 end
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
% STEP 2.7 - Create discount rate vector
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
%
%%
    Y=ones(1,1,info.nTrials);
    for i=1:info.years
        X=(exp(-info.r).^i).*ones(1,1,info.nTrials);
        Y=[Y;X];
    end
    info.△=Y(2:end,:,:); % a 79+1 vector
    info.△=permute(info.△, [2 1 3]); %transform △ as a row
    % vector
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
% STEP 2.8 - NPV Calculations
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
%
%%
%%%%%% CCGT %%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
    npv.NPVG=ones(1,1,info.nTrials); %(11x1xnTrials) matrix
    for i=0:10 %investment window hardcoded
        X=ones(1,1,1);
        for j=1:info.nTrials
            Y=(info.△(1,(1:G.life),j)*profit.PiG((G.build+i:...
                G.build+G.life+i-1),1,j)).*ones(1,1,1);
            %Y=(△(1,(G.build+i:G.build+G.life+i-1),j)*...
            % PiG((G.build+i:G.build+G.life+i-1),1,j)).*ones(1,1,1);
            X=[X;Y];
        end
        X=X(2:end,:,:);
        X=permute(X, [3,2,1]);
        npv.NPVG=[npv.NPVG;X];
    end
    npv.NPVG=npv.NPVG(2:end,:,:);
    npv.NPVG=npv.NPVG-(1000000*G.inves).*ones(size(npv.NPVG));
%%%%%% PC %%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
    npv.NPVK=ones(1,1,info.nTrials); %(11x1xnTrials) matrix
    for i=0:10
```

```
        X=ones(1,1,1);
        for j=1:info.nTrials
            Y=(info.△(1,(1:K.life),j)*profit.PiK((K.build+i:...
                K.build+K.life+i-1),1,j)).*ones(1,1,1);
            X=[X;Y];
        end
        X=X(2:end,:,:);
        X=permute(X, [3,2,1]);
        npv.NPVK=[npv.NPVK;X];
    end
    npv.NPVK=npv.NPVK(2:end,:,:);
    npv.NPVK=npv.NPVK-(1000000*K.inves).*ones(size(npv.NPVK));
%%%%%% IGCC %%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
    npv.NPVI=ones(1,1,info.nTrials); %(11x1xnTrials) matrix
    for i=0:10
        X=ones(1,1,1);
        for j=1:info.nTrials
            Y=(info.△(1,(1:I.life),j)*profit.PiI((I.build+i:...
                I.build+I.life+i-1),1,j)).*ones(1,1,1);
            X=[X;Y];
        end
        X=X(2:end,:,:);
        X=permute(X, [3,2,1]);
        npv.NPVI=[npv.NPVI;X];
    end
    npv.NPVI=npv.NPVI(2:end,:,:);
    npv.NPVI=npv.NPVI-(1000000*I.inves-1000000*euets.ccs).*ones(size(npv.NPVI));
%%%%%% NUKE %%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
    npv.NPVN=ones(1,1,info.nTrials); %(11x1xnTrials) matrix
    for i=0:10
        X=ones(1,1,1);
        for j=1:info.nTrials
            Y=(info.△(1,(1:N.life),j)*profit.PiN((N.build+i:...
                N.build+N.life+i-1),1,j)).*ones(1,1,1);
            X=[X;Y];
        end
        X=X(2:end,:,:);
        X=permute(X, [3,2,1]);
        npv.NPVN=[npv.NPVN;X];
    end
    npv.NPVN=npv.NPVN(2:end,:,:);
    npv.NPVN=npv.NPVN-(1000000*N.inves).*ones(size(npv.NPVN));
%%%%%% WIND %%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
switch info.dailyprices
    case 'daily'
        npv.NPVW=ones(1,1,info.nTrials); %(11x1xnTrials) matrix
            for i=0:10
                X=ones(1,1,1);
                for j=1:info.nTrials
                    Y=info.△(1,(1:W.life),j)*([(W.output*...
                    (365*euets.fit1level-W.om)).*...
                    ones(euets.fit1lenght,1);
                    (W.output*(365*euets.fit2level-W.om)).*...
                    ones(euets.fit2lenght,1);...
```

```
                    profit.PiW((W.build+(euets.fit1lenght+...
                    euets.fit2lenght)+i:W.build+...
                    W.life+((euets.fit1lenght+euets.fit2lenght)-1)-...
                    (euets.fit1lenght+euets.fit2lenght)+i),1,j)]).*...
                    ones(1,1,1);
                    X=[X;Y];
                end
                X=X(2:end,:,:);
                X=permute(X, [3,2,1]);
                npv.NPVW=[npv.NPVW;X];
            end
        npv.NPVW=npv.NPVW(2:end,:,:);
        npv.NPVW=npv.NPVW-(1000000*W.inves).*ones(size(npv.NPVW));
    otherwise
        npv.NPVW=ones(1,1,info.nTrials); %(11x1xnTrials) matrix
            for i=0:10
                X=ones(1,1,1);
                for j=1:info.nTrials
                    Y=info.△(1,(1:W.life),j)*([(W.output*...
                    365*euets.fit1level).*ones(euets.fit1lenght,1);
                    (W.output*365*euets.fit2level).*...
                    ones(euets.fit2lenght,1);
                    profit.PiW((W.build+(euets.fit1lenght+euets.fit2lenght)+i:...
                    W.build+W.life+(euets.fit1lenght+euets.fit2lenght-1)-...
                    (euets.fit1lenght+euets.fit2lenght)+i),1,j)]).*ones(1,1,1);
                    X=[X;Y];
                end
                X=X(2:end,:,:);
                X=permute(X, [3,2,1]);
                npv.NPVW=[npv.NPVW;X];
            end
        npv.NPVW=npv.NPVW(2:end,:,:);
        npv.NPVW=npv.NPVW-(1000000*W.inves).*ones(size(npv.NPVW));
end
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
% STEP 2.9 - Allowable investment combinations with initial budget
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
%
%%
% Round to nearest integer (lower integer, i.e. 5.6 rounded to 5.0)
combi.QN=(floor(b.bbar/N.inves):-1:0)';%Generalize for any nb of tech
combi.QK=(floor(b.bbar/K.inves):-1:0)';
combi.QI=(floor(b.bbar/I.inves):-1:0)';
combi.QG=(floor(b.bbar/G.inves):-1:0)';
combi.QW=(floor(b.bbar/W.inves):-1:0)';
 combi.QG=(2:-1:0)';
combi.CombiIndex=...
    gridmake(combi.QN,combi.QK,combi.QI,combi.QG,combi.QW);
combi.MAXCOMBI=size(combi.CombiIndex,1);
combi.CombiInves(:,1)=1000000*N.inves.*combi.CombiIndex(:,1);
combi.CombiInves(:,2)=1000000*K.inves.*combi.CombiIndex(:,2);
combi.CombiInves(:,3)=1000000*I.inves.*combi.CombiIndex(:,3);
combi.CombiInves(:,4)=1000000*G.inves.*combi.CombiIndex(:,4);
combi.CombiInves(:,5)=1000000*W.inves.*combi.CombiIndex(:,5);
```

```
combi.SumCombiInves=sum(combi.CombiInves,2);
combi.COMB=[combi.CombiIndex combi.CombiInves combi.SumCombiInves];
% SCREEENING OF ALLOWABLE INVESTMENTS
[combi.r, combi.c] = size(combi.COMB); % returns the number of rows
                                       % and columns in matrix COMB
% start a new row index for a new matrix
combi.r2 = 1;
% check row by row
for i = 1:combi.r
% if the x row implies investment costs below budget constraint,
if ((combi.COMB(i,11))<1000000*b.bbar)
% copy the row to a new matrix and increment the row index of the ...
% new matrix
combi.OKCOMB(combi.r2,:) = combi.COMB(i,:);
combi.r2 = combi.r2+1;
end
end
% The matrix OKCOMB summarizes all OK combinations
%rank lines by decreasing order of budget/ie increasing order of
% investment (Bbar then ... then exhausted budget).
combi.OKCOMB=sortrows(combi.OKCOMB,11);
combi.OKCOMBindexbbar=combi.OKCOMB(:,1:5);
combi.OKCOMBinvesbbar=combi.OKCOMB(:,6:10);
combi.INVESLEVELS=combi.OKCOMB(:,11);
combi.BUDGETLEVELS=...
    1000000*b.bbar*ones(size(combi.OKCOMB(:,11)))-combi.INVESLEVELS;
combi.OKCOMB=[combi.OKCOMB combi.BUDGETLEVELS];
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
% STEP 2.10 - Allowable inves combinations under various budget levels
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
%
%%
combi.MAX=size(combi.OKCOMB,1);
for j=1:combi.MAX % for any price paths generated
[combi.r, combi.c] = size(combi.OKCOMB);
combi.r2 = 1;
for i = 1:combi.r
    if ((combi.OKCOMB(i,11))<combi.OKCOMB(j,12))
       % variation to constraint annual spending to a given threshold
        B{j}(combi.r2,:) = combi.OKCOMB(i,:);
        combi.r2 = combi.r2+1;
    end
end
B{j}(:,12)=B{j}(:,12)-combi.OKCOMB(j,11).*ones(size(B{j}(:,12)));
B{j}=[B{j}; NaN((combi.MAX-size(B{j},1)),size(B{j},2))];
end
% OKCOMB3=cat(3,B{:}); % comma-separate list expansion
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
% STEP 2.11 - NPV COMBI Calc. for all budget levels all paths
%              and anytime
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
%
%%
% substep 1 - generate allowable combination depending on budget
```

```
for j=1:combi.MAX
    combi.OKCOMBindex{j}=repmat(B{1,j}(:,1:5), [1 1 info.nTrials]);
end
% subset 2 - prepare NPV x nTrials matrices
npv.NPV=[permute(npv.NPVN, [2 1 3]); permute(npv.NPVK, [2 1 3]); ...
    permute(npv.NPVI, [2 1 3]); permute(npv.NPVG, [2 1 3]); ...
    permute(npv.NPVW, [2 1 3])];
% subset 3 - combine NPV paths and possible combinations by budget
% levels
%COMBNPV=ones(121,11,nTrials); %pre-allocate matrix
for j=1:combi.MAX
for i=1:info.nTrials % for any price paths generated
    m.MR{j}(:,:,i) = combi.OKCOMBindex{1,j}(:,:,i)*npv.NPV(:,:,i);
end
m.MR{j} = cat(3,m.MR{j});
end
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
% STEP 2.12 - CREATE THE TRANSITION MATRIX =Bt+1=Bt-Xt
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
%
%%
TRANSITION=NaN(combi.MAX,combi.MAX); % preallocate
for j=1:combi.MAX
    for j2=1:combi.MAX
        [row]=find(combi.BUDGETLEVELS == B{1,j}(j2,12));
        if isempty(row)
        TRANSITION(j,j2)=NaN;
        else
        TRANSITION(j,j2)=row;
        end
    end
end
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
% STEP 2.13 - CREATE REGRESSOR MATRIX (time x paths x regressors)
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
%
%%
switch info.regressor
    case 'spot'
        for time=11:-1:1
                INDEP(time,:,:)=...
                    [ones(info.nTrials,1), permute(price.spot(12*...
                    (time),1,:), [3 2 1]), permute(price.spot(12*...
                    (time),2,:), [3 2 1]), permute(price.spot(12*...
                    (time),3,:), [3 2 1])];
        end
    otherwise % i.e regress against forward prices 12m and 24m ahead
        for time=11:-1:1
              INDEP(time,:,:)=...
              [ones(info.nTrials,1), permute(price.forward12m(12*...
              (time),1,:), [3 2 1]), permute(price.forward12m(12*...
              (time),2,:), [3 2 1]), permute(price.forward12m(12*...
              (time),3,:), [3 2 1]), permute(price.forward24m(12*...
              (time+1),1,:), [3 2 1]), permute(price.forward24m(12*...
```

```
                (time+1),2,:), [3 2 1]), permute(price.forward24m(12*...
                (time+1),3,:), [3 2 1])];
        end
end
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
% STEP 2.14 - RECURSIVE PART WITH MAXI TRIPLE LOOP
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
%
%%
%substeps involved:
%%%%%%%%%%%%%%%%%  DETERMINE MC %%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
% at t=9 - we compute the estimated continuation value using Longstaff
% and Schwartz method (2001)  to regress against contemporary price
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
%%%%%%%%%%%%%%%%% COMPUTE MR+MC  %%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
%%%%%%%%%%%%%%%%% COMPUTE MV+Mx  %%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
for time=11:-1:1
    if time==11
        for budget=1:combi.MAX; %(i.e. for all budget level)
            for paths=1:info.nTrials
            m.MC{budget}(11,paths)=0; % at time=11, for all budget,
                                      % all paths,
            end
        end
    else %i.e. for time=10:1
        for budget=1:combi.MAX; %(i.e. for all budget level)
        DEP{budget}(time,:)=(exp(-info.r)).*...
            permute(m.MV{1,budget}(time+1,:), [2 1]);
        % THE DEPENDENT VARIABLE DEPENDS ON BUDGET LEVEL
        alpha{budget}(time,:) = zeros(size(INDEP,3),1);
        % reg param PREALLOCATE - is it 1 or time?
        alpha{budget}(time,:) =...
            squeeze(INDEP(time,:,:))\(DEP{1,budget}(time,:,:))'; % OLS
        m.MC{budget}(time,:)=...
            squeeze(INDEP(time,:,:))*alpha{1,budget}(time,:)';
            %implied estimated continuation value
        end
    end
    for budget=1:combi.MAX; %(i.e. for all budget level)
        for inves=1:combi.MAX; % for all inves decisions
            if isnan(TRANSITION(budget,inves))
                m.MRMC{budget}(inves,time,:)=...
                    m.MR{1,budget}(inves,time,:)+NaN;
            else
                m.MRMC{budget}(inves,time,:)=...
                    squeeze(m.MR{1,budget}(inves,time,:))+...
                    (m.MC{1,TRANSITION(budget,inves)}(time,:))';
            end
        end
    end
    for budget=1:combi.MAX; %(i.e. for all budget level)
        [m.MV{budget}(time,:), m.Mx{budget}(time,:)]=...
            max(m.MRMC{1,budget}(:,time,:),[],1);
    end
```

```
end
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
% STEP 2.15 - MOVING FORWARD IN TIME ALONG THE OPTIMAL PATH
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
%
%%
[m.MVest(1,:), m.Mxest(1,:)]=...
    max((1/info.nTrials).*sum(m.MRMC{1,1}(:,1,:),3),[],1);
TR{1}=1;% i.e. for bbar in transition matrix
for time=2:11
    for x=2:time
        TR{x}=TRANSITION(TR{x-1}(1,1),m.Mxest(x-1,1));
    end
    [m.MVest(time,:), m.Mxest(time,:)]=max((1/info.nTrials).*sum(...
        m.MRMC{1,TR{time}}(:,time,:),3),[],1);
end
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
% STEP 2.16 - PROVIDING MODEL RESULTS
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
%
%
% Some relooking to explicit the optimal path
%%
for time=1:11
    results.OPTIMALPATH(time,:)=...
        combi.OKCOMBindexbbar(m.Mxest(time),:);
end
results.LOCKED=sum(results.OPTIMALPATH)*[0;K.CO2;I.CO2;G.CO2;0];
results.TOTALCAPPEAK=...
    sum(results.OPTIMALPATH)*[0;K.capacity;I.capacity;G.capacity;0];
results.TOTALCAPBASE=...
    sum(results.OPTIMALPATH)*[N.capacity;0;0;0;W.capacity];
results.ENDINGBUDGET=...
    b.bbar-...
    sum(results.OPTIMALPATH)*[N.inves;K.inves;I.inves;G.inves;W.inves];
results.PROFITABILITYINDEX=...
    100*(m.MVest(1,1)/1000000-...
    sum(results.OPTIMALPATH)*...
    [N.inves;K.inves;I.inves;G.inves;W.inves])/...
    (sum(results.OPTIMALPATH)*...
    [N.inves;K.inves;I.inves;G.inves;W.inves]);
toc % stop time counting
```

Bibliography

[1] A.K. Dixit and R.S. Pindyck. *Investment under Uncertainty*. Princeton University Press, New Jersey, 1994.

[2] F.A. Longstaff and E.S. Schwartz. Valuing American options by simulation: a simple least-squares approach. *The Review of Financial Studies*, 14:113–147, 2001.

[3] A. Gamba. Real Options: a Monte Carlo approach. *Working Paper - University of Verona*, 2003.

[4] R. Trotignon and A. Delbosc. Allowance Trading Patterns During the EU ETS Trial Period: What does the CITL Reveal? *Climate Report, Mission Climat of Caisse des Depots*, 2008.

[5] E. Alberola and A. de Dominicis. Credits and allowances: three possible scenarios. *Tendances Carbone*, (6), 2006.

[6] Caisse des Dépôts. *Tendances Carbone*, (18), 2007.

[7] Caisse des Dépôts. *Tendances Carbone*, (45), 2010.

[8] Caisse des Dépôts. *Tendances Carbone*, (7), 2006.

[9] Caisse des Dépôts. *Tendances Carbone*, (9), 2006.

[10] Caisse des Dépôts. *Tendances Carbone*, (19), 2007.

[11] Caisse des Dépôts. *Tendances Carbone*, (15), 2007.

[12] M. Mansanet-Bataller, J. Chevallier, M. Hervé-Mignucci, and E. Alberola. EUA and sCER Phase II Price Drivers: Unveiling the reasons for the existence of the EUA-sCER spread. *Energy Policy*, 2011.

[13] Caisse des Dépôts. *Tendances Carbone*, (28), 2008.

[14] Caisse des Dépôts. *Tendances Carbone*, (29), 2008.

[15] Caisse des Dépôts. *Tendances Carbone*, (30), 2008.

[16] Caisse des Dépôts. *Tendances Carbone*, (32), 2009.

[17] Caisse des Dépôts. *Tendances Carbone*, (50), 2010.

[18] Caisse des Dépôts. *Tendances Carbone*, (34), 2009.

[19] Caisse des Dépôts. *Tendances Carbone*, (49), 2010.

[20] Caisse des Dépôts. *Tendances Carbone*, (47), 2010.

[21] Caisse des Dépôts. *Tendances Carbone*, (37), 2009.

[22] Caisse des Dépôts. *Tendances Carbone*, (48), 2010.

[23] P. Linares, F.J. Santos, and M. Ventosa. Coordination of carbon reduction and renewable energy support policies. *Climate Policy*, (8):377–394, 2008.

[24] T. Couture and Y. Gagnon. An analysis of feed-in tariff remuneration models: Implications for renewable energy investment. *Energy Policy*, 38(2):955–965, February 2010 2010.

[25] IEA. The Impact of the Financial and Economic Crisis on Global Energy Investment. Technical report, IEA and OECD, 2009.

[26] M.C. Lewis and I. Curien. Emissions in remission? Looking at - and through - an EU recession. Technical report, Deutsche Bank, 2008.

[27] A.D. Ellerman and B. Buchner. Over-Allocation or Abatement? A Preliminary Analysis of the EU Emissions Trading Scheme Based on the 2006 Emissions Data. *MIT Joint Program on the Science and Policy of Global Change Report No. 141*, 2006.

[28] V.H. Hoffmann. EU ETS and Investment Decisions: The Case of the German Electricity Industry. *European Management Journal*, 25(6):464–474, 2007.

[29] A.D. Ellerman. New Entrant and Closure Provisions: How do they distort? *CEEPR (MIT) Working Paper 06-013 WP*, 2006.

[30] RWE. Annual reports. Technical report, RWE, 2004-2009.

[31] E. Delarue, D. Ellerman, and W. D'haeseleer. Short-term CO2 abatement in the European power sector: 2005-2006. *Climate Change Economics*, 1(2):113–133, 2010.

[32] R. Trotignon. Combining cap-and-trade with offsets: Lessons from CER use in the EU ETS in 2008 and 2009. *Climate Economics Chair Publications - Working Paper Series*, 2011.

[33] EDF. Financial reports. Technical report, EDF, 2004-2009.

[34] EURELECTRIC. Statistics and Prospects for the European Electricity Sector. 37th Edition EURPROG 2009. Technical report, EURELECTRIC, October 2009.

[35] E.ON. Financial reports. Technical report, E.ON, 2004-2009.

[36] European Commission. Impact assessment - accompanying document to the Draft Council Regulation on Notification to the Commission of investment projects in to EU energy infrastructure and repealing Council Regulation (EC) No736/96. Commission staff working document, European Commission, 2009.

[37] EDF. Sustainable developement reports. Technical report, EDF, 2004-2009.

[38] EDF. Annual reports. Technical report, EDF, 2004-2009.

[39] EDISON. Annual reports. Technical report, EDISON, 2004-2009.

[40] EnBW. Annual reports. Technical report, EnBW, 2004-2009.

[41] E.ON. 20-f forms. Technical report, E.ON, 2004-2006.

[42] E.ON. Company reports. Technical report, E.ON, 2004-2009.

[43] E.ON. Annual reports. Technical report, E.ON, 2004-2009.

[44] Enel. 20-f forms. Technical report, Enel, 2004-2006.

[45] Enel. Financial statements. Technical report, Enel, 2004-2009.

[46] Enel. Annual reports. Technical report, Enel, 2004-2009.

[47] Vattenfall. Annual reports. Technical report, Vattenfall, 2004-2009.

[48] PricewaterhouseCoopers. Climate Change and Electricity - The European Carbon Factor - Comparison of CO2 emissions of Europe's leading electrical utilities. Technical report, PricewaterhouseCoopers, 2009.

[49] Y. He. *Real Options in the Energy Markets*. PhD thesis, University of Twente, 2007.

[50] T. Wang and R. de Neufville. Building Real Options into Physical Systems with Stochastic Mixed-Integer Programming. In *prepared for the 8th Real Options Annual Conference*. MIT Engineering Systems Division, 2004.

[51] L. Trigeorgis. *Real Options: Managerial Flexibility and Strategy in Resource Allocation*. The MIT Press, 1996.

[52] K. Neuhoff. Investment Decisions under Climate Policy Uncertainty. *University of Cambridge Electricity Policy Research Group Working Paper*, 2007.

[53] R.A. Brealey and S.C. Myers. *Principles of Corporate Finance*. McGraw-Hill, 7th edition, 2003.

[54] J.C. Hull. *Options, Futures, and Other Derivatives*. Prentice Hall, New Jersey, 2003.

[55] S.E. Shreve. *Stochastic Calculus for Finance I: The Binomial Asset Pricing Model*. Springer Finance, 2004.

[56] S.E. Shreve. *Stochastic Calculus for Finance II: Continuous-Time Models*. Springer Finance, 2006.

[57] R. Bellman. *Dynamic Programming*. Dover Publications Inc., 1957.

[58] M.J. Brennan and Schwartz E.S. Evaluating Natural Resource Investments. *Journal of Business*, 58(2):135–157, 1985.

[59] R. Pindyck. Irreversible Investment, Capacity Choice, and the Value of the Firm. *American Economic Review*, 78(5):969–985, 1988.

[60] G. Sick and A. Gamba. Some Important Issues Involving Real Options. *SSRN Working Paper*, 2005.

[61] S. Block. Are "real options" actually used in the real world? *Engineering Economist*, 255, 2007.

[62] W.D. Walls, F.W. Rusco, and J. Ludwigson. Power plant investment in restructured markets. *Energy*, 32:1403–1413, 2007.

[63] H. Geman. *Commodities and Commodity Derivatives: Modeling and Pricing for Agriculturals, Metals, and Energy*. John Wiley & Sons - The Wiley Finance Series, 2006.

[64] J. Frayer and Uludere N.Z. What Is It Worth? Application of Real Options Theory to the Valuation of Generation Assets. *The Electricity Journal*, 1:40–51, 2001.

[65] J.H. Keppler, R. Bourbonnais, and J. Girod. *The Econometrics of Energy Systems*. Palgrave, 2006.

[66] D. Laughton and H.D. Jacoby. Project Duration, Output Price Reversion and Project Value. *Institute for Financial Research, University of Alberta Working Paper No. 3-91*, 1992.

[67] R. McDonald and D. Siegel. The value of waiting to invest. *Quarterly Journal of Economics*, (101):707–728, 1986.

[68] P. Murto. Timing of investment under technological and revenue-related uncertainties. *Journal of Economic Dynamics & Control*, 31:1473–1497, 2007.

[69] P.P. Boyle. Options: a Monte Carlo approach. *Journal of Financial Economics*, 4:323–338, 1977.

[70] G. Cortazar and E.S. Schwartz. Monte Carlo evaluation model of an undeveloped oil field. *Journal of Energy Finance & Development*, 3(1):73–84, 1998.

[71] G. Cortazar, M. Gravet, and J. Urzua. The valuation of multidimensional American real options using the LSM simulation method. *Computers & Operations Research*, 35:113–129, 2008.

[72] A. Rodrigues and M.J.R. Armada. The Valuation of Real Options zith the Least Squares Monte Carlo Method. *Working Paper - University of Minho*, 2006.

[73] G. Alesii. Assessing Least Squares Monte Carlo for the Kulatilaka Trigeorgis Real Options Pricing Model. *Working Paper - Universita di L'Aquila*, 2008.

[74] N. Areal, A. Rodrigues, and M.J.R. Armada. Improvements to the Least Squares Monte Carlo Option Valuation Method. *Working Paper - University of Minho*, 2008.

[75] S.-J. Deng, B. Johnson, and A. Sogomonian. Exotic electricity options and the valution of electricity generation and transmission assets. *Decision Support Systems*, 30:383–392, 2001.

[76] C.-L. Tseng and G. Barz. Short-term generation asset valuation: a real options approach. *Operations Research*, 50(2):297–310, 2002.

[77] S.-J. Deng and Oren S.S. Incorporating Operational Characteristics and Startup Costs in Option-Based Valuation of Power Generation Capacity. *Probability in Engineering and Information Sciences*, 17(2):155–182, 2003.

[78] J. Hlouskova, S. Kossmeier, M. Obersteiner, and A. Schnabl. Real options and the value of a generation capacity in the German electricity market. *Review of Financial Economics*, 14:297–310, 2005.

[79] L.M. Abadie and J.M. Chamorro. Monte Carlo Valuation of Natural Gas Investments. *Working Paper*, 2006.

[80] P. Murto and G. Nese. Input price risk and optimal timing of energy investment: choice between fossil- and biofuels. *Working Paper - Institute for Research in Economics and Business Administration, Bergen*, 25(02), 2003.

[81] A. Epaulard and S. Gallon. La valorisation du projet nucléaire EPR par la méthode des options réelles. *Economie et Prévision*, 3(149):29–50, 2001.

[82] E. Näsäkkälä and S.-E. Fleten. Flexibility and technology choice in gas fired power plant investments. *Review of Financial Economics*, 14:371–393, 2005.

[83] R. Madlener, G. Kumbaroglu, and V.S. Ediger. Modeling technology adoption as an irreversible investment under uncertainty: the case of the Turkish electricity supply industry. *Energy Economics*, 27:139–163, 2005.

[84] G. Kumbaroglu, R. Madlener, and M. Demirel. A Real Option Evaluation Model for the Diffusion Prospects of New Renewable Power Generation Technologies. *Working Paper - CEPE*, 2005.

[85] H. Laurikka. Option value of gasification technology within an emissions trading scheme. *Energy Policy*, 2005.

[86] H. Laurikka and T. Koljonen. Emissions trading and investment decisions in the power sector - a case study in Finland. *Energy Policy*, 34:1063–1074, 2006.

[87] L.M. Abadie and J.M. Chamorro. European CO_2 prices and carbon capture investments. *Energy Economics*, 30:2992–3015, 2008.

[88] M. Yang and W. Blyth. Modeling Investment Risks and Uncertainties with Real Options Approach A Working Paper for an IEA Book: Climate Policy Uncertainty and Investment Risk. Technical report, Paris Number LTO/2007/WP01 IEA Working Paper, 2007.

[89] R.C. Sekar. Carbon Dioxide Capture from Coal-Fired Power Plants: A Real Options Analysis. Technical report, MIT LFEE 2005-002 RP, May 2005 Report, 2005.

[90] S. Fuss, J. Szolgayova, M. Obersteiner, and M. Gusti. Investment under market and climate policy uncertainty. *Applied Energy*, 85:708–721, 2008.

[91] J. Szolgayova, S. Fuss, and M. Obersteiner. Assessing the effects of CO_2 price caps on electricity investments - A real option analysis. *Energy Policy*, 36:3974–3981, 2008.

[92] S. Fuss, D.J.A. Johansson, J. Szolgayova, and M. Obersteiner. Impact of climate policy uncertainty on the adoption of electricity generating technologies. *Energy Policy*, 37(2):733–743, 2009.

[93] M. Ventosa, A. Baillo, A. Ramos, and M. Rivier. Electricity market modeling trends. *Energy Policy*, 33:897–913, 2005.

[94] E. Alberola, J. Chevallier, and B. Chèze. Price Drivers and Structural Breaks in European Carbon Prices 2005-07. *Energy Policy*, 36(2):787–797, 2008.

[95] M. Mansanet-Bataller, A.P. Tornero, and E.V. Mico. CO2 Prices, Energy and Weather. *The Energy Journal*, 28(3):73–92, 2007.

[96] E. Alberola and J. Chevallier. European Carbon Prices and Banking Restrictions: Evidence from Phase I (2005-2007). *The Energy Journal*, 30(3):107–136, 2009.

[97] M. Mansanet-Bataller and Pardo A. Impacts of regulatory announcements on CO2 Prices. *The Journal of Energy Markets*, 2(2):77–109, 2009.

[98] E. Benz and S. Trück. Modeling CO_2 Emission Allowance Prices. *SSRN Working Paper*, 2006.

[99] G. Daskalakis, D. Psychoyios, and R.N. Markellos. Modeling CO_2 Emission Allowance Prices and Derivatives: Evidence from the European Markets. *Athens University of Economics and Business Working Paper*, 2007.

[100] W. Blyth, R. Bradley, D. Bunn, C. Clarke, T. Wilson, and M. Yang. Investment risks under climate change policy. *Energy Policy*, 35:5766–5773, 2007.

[101] M. Yang, W. Blyth, R. Bradley, D. Bunn, C. Clarke, and T. Wilson. Evaluating the power investment options with uncertainty in climate policy. *Energy Economics*, 30:1933–1950, 2008.

[102] Z. Chladná. Determination of optimal rotation period under stochastic wood and carbon prices. *Forest Policy and Economics*, 9(8):1031–1045, 2007.

[103] R.S. Pindyck. The Long-Run Evolution of Energy Prices. *Working paper MIT*, 1999.

[104] E.S. Schwartz. The Stochastic Behavior of Commodity Prices: Implications for Valuation and Hedging. *The Journal of Finance*, 52:923–973, 1997.

[105] J.J. Lucia and E.S. Schwartz. Electricity prices and power derivatives: Evidence from the Nordic Power Exchange. *UC Los Angeles: Anderson Graduate School of Management*, 2000.

[106] A. Quinet. La valeur tutelaire du carbone. Technical report, Conseil d'Analyse Strategique, 2008.

[107] M.C. Bohm, H.J. Herzog, J.E. Parsons, and R.C. Sekar. Capture-ready coal-plants - Options, technologies and economics. *International Journal of Greenhouse Gas Control*, 1:113–120, 2007.

[108] G. Fusai and A. Roncoroni. *Implementing Models in Quantitative Finance: Methods and Cases*. Springer Finance, 2006.

[109] M. Mansanet-Bataller and J.H. Keppler. Causalities between CO_2, Electricity, and other Energy Variables during Phase I and Phase II of the EU ETS. *Mission Climat Working Paper*, 2, 2009.

[110] IEA. World Energy Outlook 2008. Technical report, OECD/IEA, 2008.

[111] IEA, NEA, and OECD. Projected Costs of Generating Electricity - 2010 Edition. Technical report, IEA and NEA and OECD, 2010.

[112] IEA, NEA, and OECD. Projected Costs of Generating Electricity - 2005 Update. Technical report, OECD/IEA/NEA, 2008.

[113] U. Springer. The market for tradable GHG permits under the Kyoto Protocol: a survey of model studies. *Energy Economics*, 25:527–551, 2003.

[114] U. Springer and M. Varilek. Estimating the price of tradable permits for greenhouse gas emissions in 2008-2012. *Energy Policy*, 32:611–621, 2004.

[115] B. Buchner. Policy uncertainty, investment and commitment periods. *IEA Information Paper*, (COM/ENV/EPOC/IEA/SLT(2007)8,IEA/OECD, Paris), 2007.