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Average Cost Power Contracts and CO_2 Burdens for Energy Intensive Industry

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Alla forza di “andare avanti”
Al coraggio di “guardare avanti”
Perché la vita, come la ricerca,
è fatta di tante piccole briciole
di cui bisogna sapersi accontentare

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Abstract

Abstract

Market evidences of the last three years show that the application of the EU-ETS may endanger the European electricity intensive industries both directly and indirectly. The direct ETS burdens come from the costs of both abating emissions from old technologies and buying emission allowances on the market. The pass through of carbon cost in electricity price implies an indirect ETS charge. The combined action of these two carbon burdens may negatively affect European industries' competitiveness at international level. Some of these industries are threatening to relocate their production activities outside of Europe. This would lead to the so-called "carbon leakage" phenomenon.

Taking stock of a French industrial proposal, I consider some special contractual policies whereby electricity intensive industries can buy electricity at average cost. The rest of the market is instead priced at marginal cost. Thanks to these contracts, generators reserve part of their power plants for these industries and apply to them a price depending on the average capacity, fuel and emission costs of these dedicated units. In addition, these contracts account for the average transmission charges. Industries can choose to be supplied either at a single regional average cost price or at zonal (assimilated to nodal) average cost prices (in which case transmission costs are equal to zero).

The final objective consists in analyzing the effects provoked by the application of the single and the nodal average cost prices in the cases where generators dispose of fixed capacity or can invest in new technologies. The market for transmission services is of the "flow based market coupling" type and the allowance price is endogenous.

The results show that power contracts indeed partially relieve the direct and the indirect carbon costs and mitigate the incentive of European electricity intensive industries to relocate their activities, but with quite diverse regional impacts in correspondence with different national policies. Finally, the EU-ETS drives generators' investment choices towards clean and nuclear based technologies.

Models are formulated as non-monotone complementarity problems with endogenous electricity, transmission and allowance prices. These are implemented in GAMS and solved by PATH. They are applied to a prototype power system calibrated on four countries of the Central Western Europe represented by France, Germany, Belgium and The Netherlands.

Résume

Les évidences du marché de ces trois dernières années démontrent que la création de l'EU-ETS peut causer des dommages aux industriels électro-intensifs européens soit directement soit indirectement. L'impact direct de l'ETS est dû aux coûts de réduction des émissions des anciennes technologies et á l'achat de quotas d'émission sur le marché. Le passage du coût des permis dans le prix d'électricité opéré par les générateurs représente au contraire l'effet indirect de l'ETS. L'action combinée de ces deux impacts peut réduire la compétitivité des industriels électro-intensifs au niveau international. Certaines des ces industries menacent de délocaliser leurs activités de production en dehors de l'Europe. Cela conduirait à ce que l'on appelle le phénomène de "carbon leakage".

Considérant une proposition des industriels électro-intensifs français, j'analyse certaines politiques contractuelles par lesquelles les industries peuvent acheter l'électricité au coût moyen. Le reste du marché paie un prix basé sur le coût marginal de production de l'électricité. Grâce à ces contrats, les générateurs réservent une partie de leurs centrales électriques aux industries qui paient un prix basé sur le coût moyen de la capacité, du carburant et des émissions de ces technologies qui leur sont dédiées. Ce prix comprendre aussi les frais moyens de transmission. Les industries peuvent choisir d'être fournies à un seul prix moyen régional ou à des prix moyens zonaux (assimilés à des prix moyens nodaux).

L'objectif final consiste à analyser les effets provoqués par l'application des ces prix basés sur le coût moyen (unique and nodal) dans les cas où les producteurs disposent de capacité fixe ou peuvent investir dans des nouvelles technologies. Le marché des services de transmission est du type "flow based market coupling" et le prix des quotas d'émission est endogène.

Les résultats montrent que ces contrats en effet peuvent partialement soulager les conséquences directes et indirectes des coûts d'émission et atténuer l'incitation des industriels électro-intensifs européens à délocaliser leurs activités. Les effets sont cependant différents du point de vue régional en correspondance avec les différentes politiques nationales appliquées en matière d'électricité. Enfin, l'EU-ETS influence les stratégies d'investissement vers l'utilisation de technologies non-émettrices (renouvelables et nucléaires).

Les modèles sont formulés comme des problèmes de complémentarité non-monotones dans lesquels les prix d'énergie, de transmission et des permis d'émission sont endogènes. Les modèles sont implémentés en GAMS et résolus par PATH. Les simulations sont appliquées à un prototype de marché de l'électricité de l'Europe centre-occidental représentée par la France, l'Allemagne, la Belgique et les Pays-Bas.

Riassunto

Nel 2005 è stato istituito a seguito della Direttiva Europea 2003/87 il mercato di scambio dei permessi di emissione (EU-ETS). Chi opera nell'ETS può produrre gas serra in misura eguale al numero di permessi che detiene. Ogni permesso equivale al diritto di emettere una tonnellata di anidride carbonica ed è liberamente commerciabile. Come si evince dall'analisi di mercato tale creazione dell'EU-ETS può danneggiare le industrie Europee caratterizzate da un elevato consumo d'elettricità sia in modo diretto che indiretto.

L'impatto diretto dell'ETS è dovuto ai costi di abbattimento delle emissioni delle vecchie tecnologie e dall'acquisto dei permessi di emissione sul mercato. L'effetto indiretto è invece rappresentato dal trasferimento del costo dei permessi di emissione nel prezzo dell'elettricità. L'azione combinata di questi due effetti può ridurre la competitività delle grandi industrie Europee sui mercati internazionali. Alcuni di questo settori industriali minacciano di trasferire le loro attività produttive al di fuori dell'Europa. Questo potrebbe portare al cosiddetto fenomeno di "carbon leakage".

Facendo riferimento ad una proposta avanzata dalle grandi industrie francesi, si analizzano politiche contrattuali mediante le quali le grandi imprese possono acquistare elettricità al costo medio. Il prezzo pagato dagli altri consumatori è calcolato in base al costo marginale di produzione dell'elettricità. Grazie a questi contratti, le compagnie produttrici di energia riservano parte dei loro impianti alle grandi industrie che pagano un prezzo basato sul costo medio della capacità, del combustibile e delle emissioni, relativi alle tecnologie a loro dedicate. Tale prezzo include anche il costo medio di trasmissione. Le industrie possono decidere di essere rifornite ad un unico prezzo medio regionale oppure a dei prezzi medi zonali (assimilabili a prezzi nodali).

Il fine ultimo consiste nell'analisi degli effetti provocati dall'applicazione dei prezzi basati sul costo medio (singolo e zonale) considerando i casi in cui le imprese produttrici di energia dispongono di una capacità fissata o sono predisposte per nuove tecnologie. Il sistema di trasmissione è del tipo "flow based market coupling" e il prezzo dei permessi d'emissione è endogeno.

I risultati ottenuti dimostrano che i contratti basati sul costo medio possono parzialmente contenere i costi diretti e indiretti dell'EU-ETS e ridurre la tendenza delle grandi industrie Europee a trasferire le loro attività. Tuttavia, gli effetti differiscono su base regionale in corrispondenza delle diverse politiche nazionali applicate in campo energetico. Infine, l'EU-ETS influenza le strategie d'investimento indirizzandole verso l'impiego di risorse rinnovabili e del nucleare.

I modelli sono formulati come problemi di complementarietà non-monotoni in cui i costi di trasmissione, il prezzo dell'elettricità e dei permessi di emissione sono endogeni. Tali modelli sono implementati in GAMS e risolti mediante PATH. Le simulazioni sono condotte su un prototipo del mercato elettrico dell'Europea Nord-Occidentale comprendente Francia, Germania, Belgio ed Olanda.

Chapter 1

Introduction

1.1 Climate Change and European Emission Trading Scheme

Awareness about climate change and its consequences is growing. Climate change is a global problem, but actions to mitigate its development and consequences are regional. Europe has taken the lead in Greenhouse Gas Emission (GHG) policy. Since January 2005, the Emission Trading Scheme (ETS) has been introduced in Europe in order to curb CO_2 emissions from industrial plants as cast into law in Directive 2003/87/EC. The EU-ETS is the largest cap-and-trade system in the world and covers almost half of the EU's annual carbon emissions. Other cap and trade systems exist or are foreseen to tackle GHG emissions. They include the Japanese voluntary ETS, the New South Wales Greenhouse Gas Abatement Scheme in Australia, the Norwegian system, the Regional Greenhouse Gas Initiative in the USA and the Albertan Climate Change in Canada. In addition, other environmental policies, with their own legislation, have been announced or proposed in these and in other countries (Reinaud [45]). The emergence of these non-harmonized CO_2 regulations may create distortions of competition that can induce a relocation[1] of production activities to areas where emission policies are more lenient or even absent. The phenomenon is referred to as carbon leakage[2]. The problem treated in this thesis is related to carbon leakage. However, during the COP-13 and MOP-3 held in Bali, in December 3-15, 2007, an agreement on negotiations on the post 2012 framework (a successor to the Kyoto Protocol) was achieved. These negotiations will take place during 2008 and 2009 and should establish an ambitious global climate agreement for the period after 2012 when the first commitment period under the Kyoto Protocol expires. It is expected that a large number of countries will be included in the program. This would reduce the leakage effects and partially solve the competitiveness problem.

The European environmental policy relies on three pillars: a cap and trade system (i.e. the EU-ETS) a conservation program and a renewable program. The EU-ETS develops over two stages: the first one runs from 2005 to 2012. It is regulated by Directive 2003/87/EC. The period 2005-2007 is commonly referred to as a "learning by doing" phase. The period 2008-2012 aims at a more effective reduction of emissions and is in line with the first commitment period of the Kyoto Protocol. The

[1] Electricity price and the direct and indirect EU-ETS costs are only two of the factors that may induce energy intensive industries to relocate their production activities. The labour component should also taken into account. Indeed, the implementation of the EU-ETS exacerbates this phenomenon.

[2] Carbon leakage strongly depends on plants re-location. It measures the compensation of an industry's greenhouse gas reduction by an increase in the same industry's emissions in regions without a carbon constraint.

second stage will cover the years (2013-2020). The objective of the first stage of the EU-ETS is to reduce emissions in the energy (power and refineries) and non-energy (ferrous metal processing (iron and steel), cement, glass, ceramics and pulp and paper) sectors by 8% with respect to the 1990 level within 2012. Further, aviation may be integrated into the EU-ETS before 2012. The EU-ETS imposes a cap on CO_2 emissions and participants have to meet a certain carbon target either by abating emissions or by trading allowances on the market. Directive 2003/87/EC sets a lenient cap in the first compliance period (2005-2007) and allowed for the allocation of a large amount of free allowances. The cap is more stringent in 2008-2012, but the principle of a large fraction of free allowances is maintained. Figures 1.1 and 1.2 in Appendix 1.6 summarize the rules regulating the EU-ETS first stage.

European countries taking part in the ETS had to construct National Allocation Plans (NAPs) both for the first (2005-2007) and the second (2008-2012) commitment periods. NAPs indicate the amount of allowances granted to installations whose CO_2 emissions are regulated by the EU-ETS. These are determined per each installation included in the ETS regulation. As stated by Article 9 of Directive 2003/87/EC, *each Member State shall develop a national plan stating the total quantity of allowances that it intends to allocate for that period and how it proposes to allocate them.* Moreover, in accordance with Article 10 of the aforementioned Directive, *for the three-year period beginning 1 January 2005 Member States shall allocate at least 95% of the allowances free of charge.* However, allowances were largely distributed for free in that EU-ETS phase. In the period (2005-2007), emission caps were determined on the basis of historical data and reduction aims (European Commission [21]). Neuhoff et al. ([37]) argue that the NAPs was too generous during this first commitment period, even if other scholars, as Ellerman and Buchner ([9]), are more careful at concluding to an over-allocation of emission allowances. However, experience with the implementation of the EU-ETS during the "learning by doing" phase shows that the power sector was short on the allowance market, while allowances allocated to energy intensive industries were in excess.

The approach used to allocate emission allowances is important. While the allocation method is economically neutral if allowances are granted once for all, all the solutions proposed (auctioning, grandfathering and output-based allocations) have their benefits and drawbacks in the sequential allocations adopted in the EU-ETS. Moreover, it has been recognized that the successive allocation of free allowances and the absence of their uniform distribution may create economic distortions. In their studies, Demailly and Quirion ([6]), Hepburn et al. ([27]), Mckinsey and Ecofys ([33]), Neuhoff et al. ([37]) and Reinaud ([44]) stress the importance of the emission allocation method and its impact on investments and emission reduction incentives as well as on the international competitiveness of industrial sectors. Many policy-makers and scholars recommended auctioning as a more efficient method of allowance distribution than free allocation, because it avoids introducing distorted incentives as proved by Neuhoff et al. ([37]). Demailly and Quirion ([6]) confirm that if allowances are allocated as a function of production, output choices are correspondingly distorted. On the other side, Hepburn et al. ([27]) and Neuhoff et al. ([37]) emphasize and extensively discuss the advantages of full auctioning[3]. These authors note that the auctioning system reduces or eliminate the aforementioned distortions. Secondly, the organization of the auction allows one to introduce a price floor for allowances and provide a clear, long-term carbon price signal. This reduces uncertainty and makes investments more secure. Last, the auction revenues can be used to support R&D and to finance other investments in sustainable and more efficient technologies. The final aim is both

[3] Recall that auctioning is line with the *polluter pays principle*, which requires firms to pay to have the right to pollute.

to reduce energy costs for companies and enhance their long-term competitiveness by supporting the development of advanced technologies. All these positive effects make auctioning a desirable technique to regulate the emission policy. In accordance with Article 10 of Directive 2003/87/EC, governments had the possibility to auction up to 5% in the phase (2005-2007). This proportion is increased up to 10% in the ongoing (2008-2012) phase. In spite of all these academic recommendations, auctioning in the emission trading period (2005-2007) has been an exception rather than a rule. In fact, only four[4] of the 25 Member States auctioned and used the deriving revenues to purchase either JI/CDM or to cover the administrative costs of the scheme (Hepburn et al. [27]).

This has been noted in the proposed reversion of Directive 2003/87/EC[5] concerning the second EU-ETS stage (2013-2020). It establishes that power sector will no longer receive free allowances[6], while the number of free allowances given to large industries should decline to zero by 2020[7]. Other changes with respect to the initial version of the Directive concern the covered sectors and the mandatory EU emission reduction target. Specifically, aluminum, installations for the manufacturing of rock and stone wool, the drying or calcination of gypsum or the production of plaster boards, chemical industries and capture, transport and geological storage of greenhouse gas emissions will be included in the EU-ETS. Consequently, also N_2O and all other gases listed in Annex II of Directive 2003/87/EC will be covered by the second stage of the EU-ETS. Finally, the European Commission wants to set an independent EU commitment to achieve a 20% reduction of greenhouse gases by 2020 compared to 1990 level that it will reach the 30% in case of international agreements. As indicated in Figures 1.1 and 1.2, the effort of reducing emissions is extended also to non-ETS sectors which have to reduce by 10% their GHGs with respect to 2005 level by 2020.

In addition to the revision of the Directive 2003/87/EC, a new renewable package and an energy efficiency program have also been announced[8]. In particular, a target of 20% renewable energy by 2020 including a 10% biofuels target for transport is proposed (see Figure 1.2). The European Commission has imposed binding targets on renewable energy and those in richer European States are more stringent than those in poorer counterparts. These targets account also for the potential of renewable energy resources of each EU State. This policy wants that Member States cooperate in order to achieve environmental targets and curb emissions. European electricity companies have reacted critically to this proposal of the Commission. They argue that this renewable target in addition to the emission target of 20% is too tight. Moreover, they claim that the 20% reduction in emissions can be reached also without imposing a so stringent renewable target (Energy Argus [1]).

The European Commission also states, in the new Directive proposal, that substantial investments are needed in order to reduce the carbon intensity and improve energy efficiency. This is not an easy

[4]Denmark auctioned 5%, followed by Hungary with 2.4% and Lithuania with 1.5%. Finally, Ireland auctioned 0.75%.

[5]Proposal for a Directive of the European Parliament and of the Council, amending Directive 2003/87/EC so as to improve and extend the greenhouse gas emission allowance trading system of the Community, Brussels, January 23rd, 2008.

[6]Point 1 of Article 10a of the proposed revision of Directive 2003/87/EC states that *no free allocation shall be made in respect of any electricity production* and at point 6 of the same Article, it is specified that *no free allocation shall be made in respect of any electricity production by new entrants.*

[7]The proposed revision of Directive 2003/87/EC is particularly unclear when it comes to competitiveness and leakage. Point 8 of Article 10a states that *in 2013 and in each subsequent year up to 2020, installations in sectors which are exposed to a significant risk of carbon leakage shall be allocated allowances free of charge which may be up to 100 percent of the quantity determined in accordance with paragraphs 2 to 7.*

[8]See *Impact Assessment*, document accompanying the Package of Implementation measures for the EU's objectives on climate change and renewable energy for 2020, Brussels, January 23, 2008. Available at *http://ec.europa.eu/energy/climate_actions/*.

task as the absence of a uniform regulation of the EU-ETS among Member States and distortions caused by the different allocation systems complicated the situation at least in the first phase of the first commitment period of the EU-ETS. Possible solutions could be to enlarge the application of the EU-ETS to sectors now excluded and to review the allowance distribution as recommended by Delgado ([5]). These solutions are taken up in the new Directive proposal designed for the period after 2012 that is currently under discussion.

1.2 European Emission Trading Scheme and Energy Intensive Industries

The first compliance period of the EU-ETS (2005-2007) was presented as a "learning by doing" period. Experience indeed revealed that the functioning of the EU-ETS should be improved. But difficulties will persist independently of the improvements brought to the trading system. Climate change is a global issue but mitigating its development (and adapting to its consequences) is currently seen as a regional question. The EU is taking the lead with its cap and trade system, but it provides little transparent evidence of its impact on economy[9], even though ongoing negotiations would lead to an international climate change agreement by 2009. This agreement should enter in force after 2012 and would be in line with the second stage of the EU-ETS.

It is well recognized that the EU-ETS introduces a GHG price and hence an emission cost. This is imposed on both the energy and non energy sectors covered by the trading scheme. Constraints on nuclear development and renewable policy cause additional costs that find their way into the power system. All this will eventually bear on industries (energy and energy intensive) and eventually on European society. The mitigation of climate change is necessary but the asymmetric application of environmental policies throughout the world (at least up to now) clearly implies a distortion of competition. The European Commission has recognized this phenomenon and has decided to review the ETS Directive and to possibly modify ETS rules for the second stage 2013-2020. Energy Intensive Industries (EIIs hereafter) strongly support this revision of the EU-ETS because of the negative effects that it has on their cost balance and complain that decisions will only be made by 2011[10].

It is now recognized that the implementation of the EU-ETS has lead to two main negative impacts on EIIs: industries need not only to abate emissions (direct EU-ETS cost); but they have also to pay a higher electricity price (indirect EU-ETS cost). This second effect results from the practice of the power companies to charge the CO_2 costs into electricity prices. The phenomenon registered in the (2005-2007) ETS phase of generators passing into electricity prices the cost of allowances that they have largely received for free has been referred to as "windfall profits". According to the study conducted by Sijm et al. ([48]), "windfall profits" partially depend on the mechanism driving price

[9]See *Impact Assessment*, document accompanying the Package of Implementation measures for the EU's objectives on climate change and renewable energy for 2020, Brussels, January 23, 2008. Available at *http : //ec.europa.eu/energy/climate_actions/*.

[10]Article 10b of the proposed revision of Directive 2003/87/EC states that *by June 2011, the Commission shall, in the light of the outcome of the international negotiations and after consulting with all relevant social partners, submit to the European Parliament and to the Council an analytical report assessing the situation with regard to energy-intensive industries and goods that have been determined to be exposed to significant risks of carbon leakage. This shall accompanied by any appropriate proposals, such as adjusting the proportion of allowances received free of charge by those industries and/or implementing an effective carbon equalisation system aimed at neutralising any distortive effects.*

formation in the restructured wholesales electricity market. Competitive power generators operate their plants in merit order (see Chapter 2). In line with the marginal cost pricing system, the last plant used to produce electricity sets the price. With the implementation of the EU-ETS, power companies include the value of CO_2 allowances into their marginal costs (variable fuel costs). Carbon price thus becomes an additional cost component that contributes to raise the power price paid by final consumers. Power price increase depends on the carbon intensity of the price-setting plant. This may (but does not necessarily) increase the profitability of generators. The higher is the amount of needed emission allowances allocated for free and the higher is the profitability of power companies.

On the other side, energy intensive industries can adapt to these cost increases by accepting a reduction of their profits or by increasing their product prices. They explain that this may endanger their competitiveness on international markets and eventually imply losses of sales and market share, especially for companies extremely exposed to foreign competition. Some studies by Delgado ([5]), Demailly and Quirion ([6]), Hourcade et al. ([30]), McKinsey and Ecofys ([33]), Oberndorfer and Reggings ([41]) and Reinaud ([44]) show that the industrial sectors' exposure to the EU-ETS depends *(1)* on the industry's ability to pass the extra carbon cost onto consumers, *(2)* on the openness on international trade, *(3)* on the energy intensity and the possibility to abate carbon, *(4)* on the allowance allocation method[11] and, *(5)* on production specialization. From the analysis of these five points, industries can be subdivided into two categories: those that are exposed to international competition and those that are instead largely protected. Countries specialized in services are obviously less impacted by the carbon price than those which base their economy on industries with high carbon emissions. According to Delgado's study ([5]), EU's exports are comparatively more CO_2 intensive than those of China, the US and Japan. This depends on the composition of European export mix that is mainly composed of high carbon intensive goods. In fact, the contribution of highly carbon intensive goods, such as refinery, metallic and non-metallic products, is more significant in the European exports than in those of the US or China, where the export of low carbon intensive goods prevails (for instance, service and textiles).

This certainly has a negative impact on the international competitiveness of European industries. Moreover, the absence of a worldwide climate policy (possibly until 2009) may encourage European industries to relocate their facilities towards countries that impose less ambitious CO_2 targets with a consequent increase of carbon leakage. This is what in practice is going on, even though this situation may change after 2012 if, as already said, international authorities will be able to find a global climate change agreement by 2009.

A recent claim from giant steel company Arcelor Mittal illustrates this CO_2 problem. The company refused for some time to re-open its blast furnace in Liège (Belgium) if it did not receive the necessary allowances free. In an interview given on the 12th of December 2007 to the Belgian newspaper *L'Echo*, Lakshmi Mittal, the CEO of the company, asked Belgian public authorities to provide the carbon allowances needed, otherwise he would have moved company's steel production outsideof Europe. In that interview, the CEO argued that *we must address the problem globally and not penalize the sector in Europe. The risk is a relocation of steel production to areas without CO_2 constraints.* He simply required *good conditions before investing in Europe*[12]. On the 1st of February 2008, Bel-

[11] Allowances can be assimilated to subsidies. This implies that the allowance allocation method and the amount of allowances distributed affect the cost balance. For instance, grandfathering lessens the cost imposed by the EU-ETS system as discussed before for the "windfall profits".

[12] Sources: L'Echo, 5/12/2007. Available at
http://www.lecho.be/article/Mittal___sans_quotas_CO2__je_ne_relance_pas_Liege_.3434081.

gian public authorities finally delivered to the Arcelor Mittal CO_2 quotas demanded[13]. Eurometaux ([20]), the European Association of Metals, is of the same opinion and gives another evidence of this tendency arguing that *plant closure and disinvestments have already been announced* and it adds that it is *attributable primarily to this unaffordable cost of electricity.* Many factors cause the augment of electricity prices and among them the price of CO_2 has represented an significant component especially during the first eighteen months of the phase 2005-2007 when carbon prices were quite high. For instance, a particular steel segment, the Electric Arc Furnaces (EAF), is facing this situation. According to Reinaud's analysis, in the EAF process *electricity can account for between 50-85 per cent of total energy inputs. The electricity consumption of an EAF reaches 650 kWh/tonne of liquid steel for an average EAF plant (Arcelor). The global CO_2 emissions from EAF process therefore depends on the fuel used to produce electricity*[14]. Mechanical pulping and thermo-mechanical pulping are respectively affected by a 3-4% and 5-6% net cost increase and, again, it depends on electricity prices as indicated at page 5 of the *Report on International Competitiveness* that the European Commission has committed to McKinsey and Ecofys ([33]). This means that the pulp and paper sector is only marginally compensated by the distribution of free allowances. All aforementioned studies confirm that the EU-ETS has strong effects on the profitability of the aluminum producers[15] due both to its intensive electricity utilization and to its high openness to international competition, which does not allow them to charge these additional costs to their final consumers. Consequently, they have already largely decided to leave Europe.

Other sector and production process are highly exposed to the direct carbon cost. As indicated in McKinsey and Ecofys ([33]), *in the steel sector, the integrated production route*[16] *(BOF) is expected to be impacted in its competitiveness. In some cases, production might be relocated to other areas...The additional costs of about 17% on the marginal unit of steel production may create an incentive to shift marginal production into regions without those costs* (McKinsey and Ecofys [33] page 4.).

It is commonly reported that only electricity generating companies and refineries have benefited from the implementation of the EU-ETS.

The relocation of production activities outside of Europe entails a serious loss of welfare for the European countries with an additional environmental damage due to more lenient norms in extra-Community countries.

Nevertheless, the EU-ETS is not the unique cause of the energy intensive industries' problem. Consequently, adjustments applied only to the emission market will not guarantee the solution tp EIIs' problem. According to the reports of Cefic[17] ([2]) and Eurometaux ([20]), the lack of efficiency of electricity market implies additional burdens and this may also contribute to negatively affect industrial competitiveness. Europe should first achieve the complete liberalization of the energy markets and then eliminate the distortions provoked by the emission market. To this aim, regional market measures and infrastructure improvements should be developed in order to enable a true competition among power companies.

[13] See *http://www.cockerill-sambre.com/fr/publications/doc/news/08-02-01_CPdemarrageHF6.doc.*

[14] Reinaud [44] page 36.

[15] Aluminum sector needs of a substantial amount of electricity, but it is currently not included in the EU-ETS. The increase of power price caused by the indirect EU-ETS impact puts pressure on this sector. Moreover, the fact that it does not receive any free allowance makes the situation even worse. However, it will be included in the second ETS stage as announced in the recent Directive proposal of the European Commission.

[16] BOF stands for Basic Oxygen Furnace. This process produces mainly flat products.

[17] European Chemical Industry Council.

1.3 Energy Intensive Industries' Response

Energy intensive industries have responded to this problem with some proposals. Cefic, the European Chemical Industry Council ([2]), argues that the tools may be adopted to this aim can be organized along two lines, namely the allowance allocation method and the introduction of long-term contracts as possible solution to EIIs' situation.

This idea of long-term contracts has already seen a practical implementation in France. On the 16*th* of January 2007, Exeltium[18] signed an agreement with EdF with the view of entering in long-term contracts whereby the energy intensive industries included in the project can buy electricity at prices based on the average production costs. The duration of these special contracts are at least of fifteen years starting from 2007. The idea is that this long-term policy would boost investments in power sector and guarantee a price and industrial risk-sharing between generators and industries. These long-term contracts were supposed to be operative starting from summer 2007 and the electricity tariffs were assumed to be between 37 €/MWh and 40 €/MWh, as indicated by the French newspaper *Les Echos*[19]. However, the European Commission contested this program and proposed to include two modifications: first, the possibility for Exeltium's energy intensive industry to re-sell part of the electricity that they buy from EdF and second ensuring reasonable contracting conditions between the two counterparts involved. Since the 20*th* of February 2008, the electricity producer EdF has achieved a new agreement with Exeltium[20], which accounts for the proposal advanced by the European Commission.

1.4 Motivations and Contributions of the Thesis

Apart from the aforementioned studies and some evidences taken from newspapers (see Section 1.2), we know very little about industrial sectors. This lack of information does not help to evaluate whether or not the EIIs' claims are founded. Due to the novelty of this issue, many debates are still open. The main problem is that we do not really know if EIIs are so negatively affected by the EU-ETS. The Climate Strategy group of Cambridge is not worried about this situation. In its report on the EU-ETS impacts on competitiveness ([30]), it is stated that *these "top 20+3' potentially exposed* (to international competitiveness) *sectors*[21] *represent about 1% of UK GDP and 0.5% of UK employment. The small share of these sectors to GDP and employment does not mean that they can be ignored. On the contrary, the fact that the impact and potential leakage is focused on few specific subsectors allows for tailored and technical solutions to address leakage concerns*[22]. It improves *robust economic performance and the credibility of EU ETS as an instrument for delivering emission reductions*[23]. Also in the Stern review, we can find a similar result. Quoting page 279 of the Stern Review ([50]),

[18]Exeltium is a French limited company founded by 7 industrial groups characterized by an intensive electricity consumption. These are: Air Liquide, Alacan, Arcelor Mittal, Arkema, Rhodia, Solvay and UPM-Kymmene ([42]).

[19]Sources: *http : //pepei.pennnet.com/display_article/282333/6/ARCHI/none/none/1/French − EDF, −big − power − users − Exeltium − sign − MoU − on − long − term − tariff/.*

[20]Source: *http : //www.daily − bourse.fr/news.php?news = AFP080220100121.xn32kori.*

[21]This study is conducted on the basis of UK data by assuming an allowance price of 20 €/ton and induced electricity price increase of 10 €/MWh. The sector analyzed are: cement, basic iron and steel, refined petroleum, fertilisers and nitrogen, aluminum, other inorganic basic chemicals, pulp and paper, malt, coke oven, industrial gases, non-wovens, refined petroleum, household paper, finishing of textiles, hollow glass, rubber tyres and tubes, veneer sheets, flat glass, copper and casting of iron.

[22]Hourcade et al. [30] page 51.

[23]Hourcade et al. [30] page 1.

a detailed analysis of the key divers of costs suggests the estimated effects of ambitious policies to stabilise atmospheric GHGs on economic output can be kept small, around 1% of national and world product averaged over the next fifty years.

However, as already discussed, Delgado ([5]) shows that the European exports are carbon intensive and that the EU-ETS may affect the competitiveness of the industrial sectors open to international trade. Helm in the article published on *The Wall Street Journal* on the 13th of March 2008, assumes a critical position. In his opinion, tackling climate change is a costly objective especially now that the European Commission is going to set ambitious target for biofuels and renewable technologies. He does not believe in the Stern report forecast of 1% GDP because this evaluation is made under the assumption of an efficient and optimal use of new technologies. He claims that *there is no evidence that policy designed to reduce emissions is going to be optimal or efficient*[24].

In this PhD thesis, we assume an impartial attitude with regard to this ongoing debate. We realize that the introduction of the EU-ETS has affected energy intensive industries, but we are not able to exactly quantify its impact. Taking up of the French energy intensive industries' proposal discussed in Section 1.3, we explore the effects of the possible application of special contracts, based on the average cost pricing system, which would mitigate the impact of CO_2 costs on electricity prices paid by industries. In particular, we test two innovative pricing approaches based respectively on a single and nodal average costs.

The experimentation of these special contracts represents the originality of the thesis. EIIs' problem is not easy to treat for several reasons: *(i)* the problem is completely new as well as its economic implications; *(ii)* average cost based power contracts represent what industries really ask for, even thought, up to now, we are not able to foresee EIIs' reactions after their implementation; *(iii)* the ETS Directive is continuously changing and this complicates even more the situation. Finally, the numerous variables included in our models make the thesis dense of information. In particular, we consider the emission market, the transmission market and the average cost pricing system, which is not the standard procedure. Note that all these effects are difficult to combine all together because they may imply (especially the average cost pricing approach) some mathematical difficulties. We will return on this point in the following Chapters.

1.5 Methodological Approach

The objective of the present thesis is to contribute to improving the understanding of the energy intensive industries' issue. We do this by implementing models (on the basis of available information) and in analyzing the corresponding results.

With take the view that the industrial sectors' problem has a long-term dimension. To the best of our knowledge, there are today no models describing the situation of EIIs. As already discussed, the EU-ETS negatively impacts industries both directly and indirectly. We do not know the extent of this impact or the remedies that can relieve it. Our aim consists in studying both aspects. For this reason, we analyze the application of average cost power contracts to a power market where the power sector is described on a technological basis (different type of generation units with their technological characteristics). Because of the lack of data, we aggregate industries in one sector and we quantify their reactions to the EU-ETS impacts by the means of their electricity demand function. Needless to say this is a rough representation of the industrial sector, but is sufficient to get insight

[24] *Sins of Emissions*, The Wall Street Journal, Thursday, March 13, 2008.

into the EIIs' issue. Moreover, the potential of this approach is that it captures both the direct and the indirect EU-ETS impacts. This permits to have a quite realistic image of the carbon leakage and competitiveness problems. We consider three main stages.

We start by analyzing the EU-ETS indirect impact on industries on the sole basis of this change of their electricity demand when power prices are affected by carbon policy. This represents the most natural way to approach the problem as the increase of electricity prices has been the main complaint of the EIIs in the first compliance period of the EU-ETS. To this aim, we first consider a perfectly competitive market, where generators supply two consumer groups: energy intensive industries and non energy intensive sectors (N-EIIs hereafter) representing the rest of the market. Power capacity is fixed and both demand segments pay an identical electricity price that is set at the marginal production cost. We introduce this reference case in order to check the behaviour of our model. In this first stage, we account only for emissions generated by electricity production. This model represents our reference case that we progressively modify by first introducing a different pricing system for industries and then an investment assumption. We justify our choosing perfect competition as a reference case on the basis of usual arguments. The effects of the application of average cost prices and investments in a perfectly competitive market are unambiguously defined. It is not the case in an oligopoly market. Among the imperfect competition models, Cournot models are the most commonly used even though rarely justified on the basis of observations. Although the Cournot assumption is now a well-understood competition paradigm, its interaction with average cost pricing system and investment problems would lead us to uncharacterized markets. For these reasons and taking into account the scope of our analysis, we will work with a perfectly competitive market. This assumption implies that also energy intensive consumers are priced at the marginal cost in our reference model. In reality, industries buy electricity by contracts aligned to forward prices. In our models, we consider a temporal framework of one year, subdivided in two sub-periods with different durations: summer (seven months) and winter (five months). In the reference case, we may assume that industries conclude two forward contracts (one in summer and the other in winter) with a global duration of one year[25] whose price are assimilated to the marginal cost prices of the two periods modelled. Starting from this assumption, we meet that EIIs are currently complain about this system and suggest alternative pricing mechanism. Considering this situation, we thus modify the reference case by introducing special calendar contracts based on (single and nodal) average cost prices in order to accommodate the request of industries. In all these cases, the long-term is modelled assuming that industries are more price elastic than the other part of the market. These models and the corresponding results are respectively presented in Chapters 3 and 4.

In the second stage, we suppose that generators invest in new capacity. The main structure of our investment models does not change with respect to the former cases and still account for the indirect ETS only. However, the additional investment assumption allows a more realistic representation of the long-term. We still assume that N-EIIs buy electricity at the marginal cost, since this represents the standard mechanism adopted to price this market sector. Chapter 5 is devoted to both a theoretical and an empirical analysis of this problem.

In the third and last stage, we analyze both the direct and the indirect EU-ETS impacts on energy intensive industries. We do that by casting the direct and indirect effects in their electricity demand function. In fact, we assume that industrial electricity consumption is affected by two pricing factors: first the price of electricity and second the cost of allowances bought on the market. These models are an extension of those presented in the first and second stages since they also include carbon emissions

[25] DG Competition rejects contracts that last more than one year.

deriving from industrial production activities. Chapter 6 describes the results of these new models.

This step by step methodology allows us to analyze the energy intensive industries' problem under progressively more complex aspects. Note that the structure of the model is such that generators are constrained to conclude average cost based contracts with energy intensive industries. The natural question is whether or not power companies gain from the application of these long-term contracts.

Finally, we assume that fuel cost, capacity cost and reference demand of N-EIIs and EIIs are identical in all three stage studied. We adopt this strategy in order to examine the evolution of our results under different scenarios.

1.6 Appendix: Past, Present and Future of the EU-ETS

In this Appendix, we show the evolution of the EU-ETS by comparing its regulation in the two stages. Recall that the first stage covers the period (2005-2012), while the second stage goes from 2013 to 2020. Specifically, we consider the sectors and the GHGs covered, the allocation methods, the targets and the cap imposed on emissions. These are reported in Figures 1.1 and 1.2. For the first stage (2005-2012), we refer to Directive 2003/87/EC; while for the second stage (2013-2020) we account for the proposals of the new ETS Directive.

EU-ETS Commitment Period	**First Stage (2005-2012)**		**Second Stage (2013-2020)**	
	First Phase (2005-2007)	**Second Phase (2008-2012)**	**ETS Sectors**	**Non ETS Sectors**
Sectors	**Energy:** *1.Power and refineries;* *2.Coke ovens* **Non Energy (EIIs):** *1. Production and processing of ferrous metals (iron and steel);* *2. Cement;* *3. Glass;* *4. Ceramics;* *5. Pulp and paper* Possibly **Aviation** by **2011**		**Energy:** *1. Power and refineries;* *2. Coke ovens* **Non Energy:** *1. Production and processing of metals (iron and steel);* *2. Production and processing of non-ferrous metals;* *3. Aluminium;* *4. Installations for the manufacturing of rock and stone wool, for the drying or calcination of gypsum or for the production of plaster boards;* *5. Chemical industries;* *6. Capture, transport and geological storage of greenhouse gas emissions;* *7. Cement;* *8. Glass;* *9. Ceramics;* *10.Pulp and paper*	**Transport** **Housing** **Agriculture** **Waste**

Figure 1.1: Sectors Included in the Two EU-ETS Stages

EU-ETS Commitment Period	First Stage (2005-2012)		Second Stage (2013-2020)	
	First Phase (2005-2007)	**Second Phase (2008-2012)**	**ETS Sectors**	**Non ETS Sectors**
Gas Covered	**CO2**		All gases listed in Annex II of Directive 2003/87/EC **(CO2, CH4, N2O, HFC, PFH, SF6)**	
Allocation Methods	**For all ETS Sectors:** *1.* **Grandfathering** (95%); *2.* **Auctioning** (5%) Member States choose the allocation method	**For all ETS Sectors:** *1.* **Grandfathering** (90%); *2.* **Auctioning** (10%) Member States choose the allocation method	**Energy Sector (also new entrants):** Only Auctioning; **Non Energy Sectors:** Free allowances for EII declining to zero in 2020 **Uniform allocation method**	**CDM and JI Projects**
CAP	**By Member State**		**Unique**	**NO CAP**
Reduction Target	**CO2 Reduction 8% by 2012** with respect to 1990 level		**GHG Reduction 20% increased to 30% in case of international agreements by 2020** with respect to 1990 level	**GHG Reduction 10% by 2020** with respect to 2005 level
Other Targets	**NO**		**Renewable energy 20% including 10% of biofuels**	**NO**

Figure 1.2: GHGs, Allocation Methods, Cap and Targets of the Two EU-ETS Stages

Chapter 2

Model Assumptions, Input Data and Mathematical Background

2.1 Market Studied

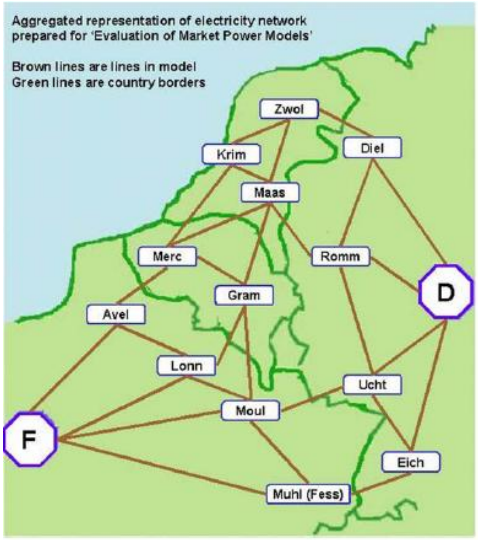
This Section describes the assumptions of our models. We proceed by first describing the market studied and its network infrastructure and then analyzing market players. The analysis is applied to a stylized representation of the electricity market of the Central Western Europe (CWE hereafter) for which data are available on the Energy Research Center of the Netherlands (ECN) website ([8]). The network[1] is depicted in Figure 2.1.

Models' calibration is based on data updated to 2005. This choice has been influenced by several different factors. First, 2005 is the year of the inception of the EU-ETS for which emissions are recognized to be independently and consistently verified. Second, network data were reasonably valid only for that year. The consistency of the analysis implies that also fuel costs, power capacities and consumers' reference demand have to refer to 2005. Recall that we use these 2005 data to implement all the models presented in the following Chapters. This assumption allows us to compare the results of our different scenarios.

2.1.1 Network and Nodal Pricing System

The network in Figure 2.1 accounts for 15 nodes located in four different countries: Belgium, France, Germany and the Netherlands. Supply and demand are located at seven nodes: two in Belgium (Merchtem and Gramme), three in the Netherlands (Krimpen, Maastricht and Zwolle), one in Germany ("D") and, finally, one in France ("F"). The remaining German and French nodes are passive and are only used to transfer electricity. Nodes are connected by 28 arcs with limited capacity. There are 10 trans-border lines that connect Germany to the Netherlands (2 lines), the Netherlands to Belgium (3), Belgium to France (3) and France to Germany (2). The grid is modeled by DC load flow approximation and represented using a Power Transfer Distribution Factor ($PTDF$) matrix provided by ECN ([8] and see Figure 2.1 for the values).

[1] Note that Hobbs et al. ([29]) and Neuhoff et al. ([39]) also adopted this network in their case studies.



Flowgate	Reactance	Max Capacity [MW]
AVEL_LONN	22,2	2762
D_DIEL	45,9	20000
D_EICH	45,9	20000
D_ROMM	45,9	20000
D_UCHT	45,9	20000
DIEL_ROMM	69,2	1842
DIEL_ZWOL	12,2	2971
EICH_UCHT	41,3	3329
F_AVEL	45,9	20000
F_LONN	45,9	20000
F_MOUL	45,9	20000
F_MUHL	45,9	20000
GRAM_LONN	45,2	1207
GRAM_MOUL	156,5	267
KRIM_MERC	34,2	936
LONN_MOUL	27,1	1842
MAAS_GRAM	41,8	641
MAAS_KRIM	29,1	1842
MAAS_MERC	61,0	641
MERC_AVEL	55,4	898
MERC_GRAM	31,1	1842
MOUL_MUHL	38,2	3329
MUHL_EICH	11,5	1282
ROMM_MAAS	28,3	896
ROMM_UCHT	43,0	1842
UCHT_MOUL	25,4	1326
ZWOL_KRIM	33,1	1842
ZWOL_MAAS	50,0	1842

Figure 2.1: Central Western European Power Market and Network Line Capacities

Generally, this network representation includes a node, the so–called hub node, where electricity asks and bids converge and clear all together. The hub can be considered as a virtual market that sets the electricity price. In this system, generators send the electricity they produce to the hub where energy is withdrawn and delivered to consumers located in the different nodes. Power trade must respect the capacity limit of the lines composing the grid. The $PTDF$ matrix determines both the directions and the proportions of power flowing through network lines as a result of the difference between nodal injections and withdrawals. In particular, the sum over all nodes of the proportion of the net power flow injected into all nodes and passing through a network line to reach the hub minus the sum over all nodes of the proportion of the net power flows injected from the hub and withdrawn from each node must be lower than the capacity of the line used to transfer electricity. This constraints the set of possible injections and withdrawals. Congestion arises when at least one of the grid lines is overloaded[2]. National Transmission System Operators (TSO hereafter) are in charge of relieving the network congestion and their operating costs are paid by final electricity consumers. Congestion costs are added to the electricity price set at the hub and differ with generators and consumers' locations in the network. This implies a nodal pricing system.

In order to illustrate the interpretation of the $PTDF$, we recall the simple case of a three nodes system as indicated in Figure 2.2, where generators are located in nodes 1 and 2, while consumers are placed at node 3. Connecting lines have identical length and physical restrictions. All generators deliver electricity to node 3 according to Kirchhoff's current and voltage laws[3].

Electricity injected at node 1 can follow two paths to get to node 3: the first is direct (1-3) while the second is indirect (1-2)+(2-3). Since the indirect path (1-2)+(2-3) is twice as long as the direct

[2]We do not model here the so–called "n-1 reliability criterion". It ensures that in case a line is cut off, the remaining available lines can bear the redistributed flows without damaging the security of the system.

[3]The first Kirchhoff's law establishes that the net flow into a node equals zero (i.e. the power flowing into any node corresponds exactly to power going out that node); whereas the second law states that the net voltage drop around any loop in the network is zero.

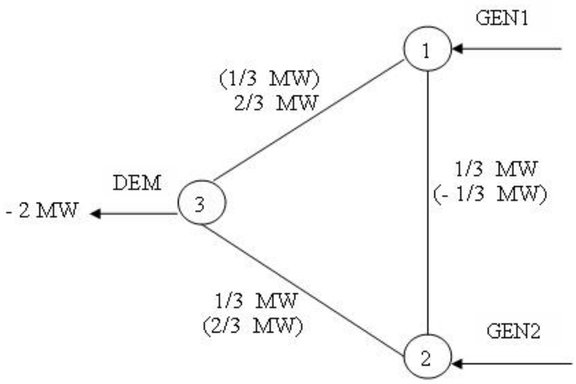


Figure 2.2: Three Nodes Example

one (1-3), a unitary injection of electricity in node 1 followed by a withdrawal at node 3 generates flows of 1/3 and 2/3 respectively on lines (1-2)+(2-3) and (1-3) as indicated in Figure 2.2. A unitary injection in node 2 has a similar behaviour on connections (2-3) and (2-1)+(1-3). As a consequence, two identical flows of opposite directions (i.e. (1-2) and (2-1)) pass through line (1-2) and cancel out.

Since a flow can follow both directions of a line, we have to account for the upper and lower bounds of each line of the grid. That is the reason why, usually, network is modelled using two transmission constraints representing the upper and the lower line bounds.

2.1.2 Generators

We assume that electricity is provided by eight generators corresponding to the mainstream power companies operating in the market considered. In Germany, we account for E.ON Energie AG, ENBW Energieversorgung Baden-Württemberg, RWE Energie AG and Vattenfall Europe. France is represented by Electricité de France (EdF), while Belgium by Electrabel. In the Netherlands, power stations are owned by Essent Energie Productie BV and Nuon. Finally, the remaining small generators are assembled in a "fringe" in each country.

Generators produce electricity by operating eight different technologies: hydro[4], renewable, nuclear, lignite[5], coal, CCGT, old gas (hereafter gas) and oil-based stations. These plants are characterized by their available capacities, fuel, emission and fixed costs.

Table 2.2 shows the available power capacities by node and technology. Note that power companies can own different plants in different nodes. For instance, EdF has nuclear installations both in France and in Belgium and the reverse happens for Electrabel[6]. Available capacities are computed

[4]We include only running-of-river plants and we do not account for pumped storage stations that usually supply peak-load.

[5]Lignite is a particular kind of coal, but it is locally exploited because it has a low calorific value.

[6]In accordance with our input data, EoN owns all technologies in Germany (apart from oil-based plants) and coal and CCGT installations in Krimpen. Electrabel runs all technologies (except for lignite) in Belgium. Moreover, this company has some coal in Germany, hydro and nuclear in France and finally, coal and CGGT in the Netherlands. EdF owns all technologies in France (included 77 MW of lignite (see Table 2.2)) and nuclear in the Belgian node Gramme.

multiplying the MW of existing capacities by the corresponding availability factors. These factors measure the amount of time that power stations are able to produce electricity over a certain period, divided by the amount of the time in the period. They depend on technology as reported in Table 2.1[7]. Moreover, the availability factor of hydro plants varies also over countries. Generally, it is obtained by dividing the net hydro production by the net maximum hydro capacity for a specific year. In our specific case, we used 2005 electricity production data provided by Eurostat ([22]) and UCTE ([52] and [53]). Our computations show that the availability proportions are 32.4% (in Germany), 28.9% (in France), 12.3% (in Belgium) and 0% (in the Netherlands). Note that because of their geographical conformation, the Netherlands cannot exploit hydro to produce electricity.

	Hydro	**Renewable**	**Nuclear**	**Lignite**	**Coal**	**CCGT**	**Gas**	**Oil**
Factor	different	25%	75%	85%	80%	85%	85%	85%

Table 2.1: Availability Factors by Technology (%)

We took as references for the existing capacities the 2005 reports published by the power companies included in our study (EdF [10] and [11]; Electrabel [12]; EnBW [13]; EoN [14], [15] and [16]; Essent [17] and [18]; Nuon [36]; RWE [46] and [47]; and Vattenfall [56] and [57]).

Available Capacity							
	Germany	**France**	**Merchtem**	**Gramme**	**Krimpen**	**Maastricht**	**Zwolle**
Hydro	1,505	6,804		13			
Renewable	4,583	1	20.43	21.32	101.26	101.26	102
Nuclear	15,007	45,369	2,078	2,204	337		
Lignite	17,783	77					
Coal	24,613	8,824	1,564	979	3,128		482
CCGT	13,544	8,164	2,589	1,207	4,432	2,917	4,834
Gas	2,147	256	194	170	833		
Oil		4,760	55	194			
Total	**79,183**	**73,535**	**6,500**	**4,788**	**8,831**	**3,018**	**5,417**

Table 2.2: Available Capacity by Node in MW

We use staircase (piecewise constant) marginal cost curves to represent supply functions of each generators since technologies are operated in merit order[8]. The merit order is determined by the

EnBW disposes of all technologies in Germany (apart from renewable) and has some additional nuclear in France. The Dutch company Essent has the control of some renewable plants in Germany and in the Netherlands owns renewable, coal and CCGT. Nuon has only plants in the Netherlands and in particular these are renewable, coal, CGGT and old gas. In contrast, RWE and Vattenfall own plants (all technologies but not oil) in Germany. Last, the fringe run all technologies everywhere.

[7]Source: *http://en.wikipedia.org/wiki/Availability_factor*.

[8]The merit order is a method adopted to rank technologies by starting from those with the lowest to those with the highest marginal costs. It means that the consumers' electricity demand is firstly covered by base-load technologies, characterized by low variable costs, and then, when power consumption increases more expensive power stations are run. These are usually defined as medium and peak load plants. In accordance with the definition given by Stoft ([51]), a base-load plant is run most of the time and it is stopped rarely, like nuclear and lignite. These cover the minimum load (demand) for a given control area. Mid-load plants are "intermediate" capacities which operate for more hours than peak plants and fewer than base-load plants (approximately 20% to 60% of the time, like coal stations). Finally,

emission and fuel cost of each plants. Because emission costs depend on the allowance price that is itself determined by the model, the merit order is endogenous.

Table 2.3 report generators' fuel costs. These are computed on the basis of public data[9] and account for the efficiency factor of each technology[10]. In our models, we consider both for the fixed capacity and investment assumptions. In order to simplify our dataset and to easily compare the results of our different models, we assume that new power plants are as efficient as already existing capacities. This implies an identical cost structure for both classes of technologies (old and new ones). Someone may argue that this representation is not realistic, but we recall that our main objective is to analyze the impact of the application of special contracts on EIIs. Introducing different assumptions on capacity may deviate the evaluation of the effects due to special contracts. However, we precise that our models do not exclude the possibility to apply different efficiency rates.

Technology	**Fuel costs**
Hydro	0.00
Renewable	0.00
Nuclear	4.50
Lignite	14.86
Coal	21.62
CCGT	36.35-37.08
Gas	54.92-55.20
Oil	46.9-67.62

Table 2.3: Fuel Costs by Technology in €/MWhe

Table 2.4 shows the annual fixed capacity charges. These will represent a key determinant of electricity prices in the average cost pricing models (both with and without investments). Capacity charges depend on nodes and technologies, but do not differ per generator. Moreover, we assume that fixed costs of old and new capacities are identical. We adopt the amortized overnight costs method presented by Stoft[11] ([51]) to compute the values reported in Table 2.4. In particular, we use the following formula:

$$FC = \frac{r \cdot C}{1 - \frac{1}{(1+r)^l}}$$

The construction costs of the technology included in the model (C) are discounted at some cost of capital (r) in accordance with the installation life (l). Each technology has its own life and its construction costs, which vary with plant location[12].

Note that there are some blank cells in Table 2.4. This representation reflects both the availability of old capacities (see Table 2.2) and the possibility of investments in new power plants. Starting

peak-load are technologies characterized by low fixed and high variables costs. They are designed to serve demand in peak and, in general, these are CCGT and diesel.

[9]Sources: WNA Report [58] and $http://www.uic.com.au/nip08.htm$ (for nuclear), EWI/Prognos – Studie: Die Entwicklung der Energiemärkte bis zum Jahr 2030, p. 12 and BMWa, www.bmwa.bund.deIEA (for lignite), $www.bafa.de/1/de/service/statistiken/kraftwerkssteinkohle.php$ (for coal), $www.bmwi.de/BMWi/Navigation/Energie/Energiestatistiken/energiestatistiken$ (for gas) and IEA, *Weighted Average CIF Cost of Crude Oil*, Annual Statistical Supplement for 2005, released August, 25 2006 (for oil).

[10]In particular, we use the efficiency rates for lignite/coal and CCGT installations adopted by Smeers [49]. They are 37% and 49% respectively. We assume that nuclear is 100% efficient, while hydro and renewable's efficiency is 25%.

	Germany	France	Merchtem	Gramme	Krimpen	Maastricht	Zwolle
Hydro	488,025	488,025	488,025	488,025			
Renewable	403,541	367,264	367,264	367,264	760,498	760,498	760,498
Nuclear	128,619	112,876	112,876	112,876	155,609		
Lignite	109,973	96,588					
Coal	109,973	96,588	109,973	109,973	109,973	109,973	109,973
CCGT	36,452	43,417	69,464	69,464	74,688	74,688	74,688
Gas	36,469	43,351	69,397	69,397	74,621	74,621	74,621
Oil	36,452	43,417	69,464	69,464	74,688	74,688	74,688

Table 2.4: Annual Fixed Costs by Node and Technology in €/MW

from hydro capacity, one can see that the Netherlands do not dispose of hydro capacity. As already explained, this depends on the the geographical characteristics of this country. Consequently, neither old hydro plants are available nor new hydro can be built. Renewable plants are available in all nodes and moreover the European Commission encourages their development as indicated by the new renewable target foreseen for the after 2012 period. In accordance with our input data, old nuclear stations are located in Germany, in France, in Belgium and in the Dutch node Krimpen (337 MW, see Table 2.2).We report their costs in Table 2.4. However, under the current situation, investments in nuclear are allowed only in France. Considering the values reported in Table 2.2, lignite is mainly available in Germany. There is also a negligible proportion of lignite in France and we report its cost in Table 2.4. Therefore, we assume that generators can run new lignite plants only in Germany. Except for its environmental cost, there are no other constraints that limit the exploitation of the existing and the construction of coal stations. An identical reasoning holds also for gas and oil-based plants. In our models, we allow generators to invest in these technologies, even though they are costly in terms of fuel and emissions. For this reason, we indicate their fixed costs in each location. Finally, CCGT is available in all nodes (see Table 2.2) and moreover because of its lower carbon impact is more convenient than coal in terms of investments.
IEA ([31]) is the source of the overnight costs used to compute the values reported in Table 2.4[13].

Finally, the efficiency rate of old gas and oil-based stations is around 40%.

[11] Stoft [51] page 35.

[12] Plant life differ per technology. We assume that hydro, wind, gas and oil based plants have life duration of 20 years. In contrast, nuclear, lignite and coal based installation can be exploited for 40 years. Finally, CCGT can be run for 30 years. We assume a discount rate r of 10% as in Stoft ([51] page 35). Finally, construction costs are based on data provided by IEA ([31]).

[13] We took wind data reported at page 60 of IEA ([31]) as references for the overnight construction costs of renewable capacities. In fact, wind is a substitute of renewable and moreover, data were available for three of the four countries modelled. In Belgium, the overnight construction costs of onshore wind technologies amount to 1,267 USD/kWe. In Germany, there is a distinction between onshore and offshore wind plants. Installing an offshore wind station costs 1,888 USD/kWe, while the onshore type is cheaper (1,144 USD/kWe). In average, the cost becomes 1.516 USD/kWe. On the contrary, in the Netherlands, offshore wind plants are much more expensive: 2,622 USD/kWe. We assimilate French overnight construction costs to the Belgian ones. Note that in order to be prudent with wind/renewable policy, we multiply by a factor of four these costs, even thought a factor of two would have been more realistic.
A similar cost tendency occurs also for CCGT (and also gas and oil-based plants). According to the values reported at page 50 of IEA report ([31]), in Belgium the overnight construction costs of a CCGT plant amount to 958 USD/kWe, in France 599 USD/kWe, in Germany 503 USD/kWe and finally in the Netherlands 1,030 USD/kWe (almost double than in France and in Germany).

2.1.3 Consumers: Energy intensive industries (EIIs) and non energy intensive industries (N-EIIs)

We distinguish two independent consumer groups: energy intensive industries (EIIs) and the other sectors (N-EIIs) including households, small consumers of electricity and tertiary. Consumers' demand functions are assumed to be linear and differ over nodes. As indicated in Table 2.5, we consider two periods: "summer"and "winter" measured in hours per year, with different durations. They are required to be identical in all countries included in the network. We state that "summer" lasts seven months (5,136 h), while "winter" corresponds to the remaining five months (3,624h). The duration of the summer and winter periods accounts for the evolution of electricity consumption in Germany in 2005. We take Germany as reference since it is our hub node. Computations are based on data provided by UCTE ([54]). We simply notice that, in 2005, the average of German electricity consumption in October, November, December, January and February has been higher than in other months. On the basis of that, we define the duration of the two periods. We consider realistic to assume that N-EIIs consume more electricity in winter than in summer, while EIIs demand a constant level of electricity over the year. In fact, their nodal reference demand is identical in summer and in winter (see Table 2.5). Note that data reported in Table 2.5 refer to hourly demand. It means that they represent the EIIs and N-EIIs' electricity consumption in one hour summer and in one hour winter. This implies that N-EIIs' annual electricity consumption is computed by summing the results obtained by the product of the values in Table 2.5 and the duration of the respective periods. The EIIs' is easily computed by multiplying their summer or winter demand by 8760, the number of hour in one year. In this way, we consider the consumers' base-load electricity demand and do not model daily peak and off-peak demand. We fully acknowledge that this is not sufficient to get a good representation of the system. However, it is sufficient to illustrate the phenomenon at work while keeping the model simple.

Nodes	**Summer**		**Winter**	
Reference Demand	**EIIs**	**N-EIIs**	**EIIs**	**N-EIIs**
Germany	29,655	18,980	29,655	48,835
France	18,527	20,323	18,527	45,373
Merchtem	4,306	1,310	4,306	4,580
Gramme	1,851	560	1,851	1,960
Krimpen	3,168	2,950	3,168	7,469
Maastricht	1,082	703	1,082	1,810
Zwolle	1,941	1,169	1,941	3,033

Table 2.5: EIIs and N-EIIs' Reference Demand in MWh

ECN ([8]), Eurostat ([22]) and UCTE ([52] and [54]) are the references for the data in Table 2.5. Again, these data refer to 2005[14].

Demand curves are calibrated through a reference point and an elasticity at that point. A wholesale

[14] We compute the 2005 demand of EIIs and N-EIIs by using UCTE ([52]) annual demand by country and some proportions previously defined on the basis of Eurostat data ([22]). We then define EIIs' hourly demand by dividing this value by 8760, the number of hours in one year. We determine N-EIIs' periodical electricity consumption by first subtracting the EIIs' demand from UCTE data ([54]) and then computing an average of the residual values considering the respective durations of summer and winter. Finally, consumers' nodal demand is defined using ECN proportions ([8]).

reference price of 40 €/MWh is applied to EIIs and N-EIIs' demand functions in both periods. Since our priority consists in analyzing consumers' reactions to the introduction of the EU-ETS, we model long-term demand function. N-EIIs are expected to behave less flexible and then we assume that their demand elasticity is -0.1 in the reference point. Contrarily, we set industries' demand elasticity at -1 in order to account for their ability to leave Europe in case of too high electricity prices[15]. This industrial elasticity's assumption may appear too strong. In reality, we do not have much information about industrial demand response. Industrial elasticity set at -1 may be too high, but the goal of our study is to describe the extent to which the application of an average cost pricing policy can accommodate industries operating in certain market situation. Nevertheless, we also test the case where the industrial demand elasticity equals -0.8. This additional analysis is conducted by the means of a welfare analysis that is presented respectively in Chapters 4 and 5. Our objective is to check the robustness of our results in terms of policy effectiveness.

2.1.4 Emission Market

The ETS policy is modelled by an emission constraint. Table 2.6 reports the emission factors by technology that we took from Davis and URS Corporation's report ([4]).

	Hydro	**Renewable**	**Nuclear**	**Lignite**	**Coal**	**CCGT**	**Gas**	**Oil**
Factor	0	0	0	0.97	0.9542	0.432	0.6266	0.8441

Table 2.6: Emission Factor by Technology in Ton/MWh

As indicated in Section 1.5, our analysis is conducted step by step. In the first stage described in Chapters 3 and 4, we investigate the indirect ETS impact on industries represented by their demand function. In other words, we quantify the variation of EIIs' electricity demand when power price is affected by emission (opportunity) costs. For this reason, in Chapters 3 and 4 we analyze an emission market restricted to the sole power sector and we do not model allowance trading with EIIs. This restrictive assumption is selected in order to simplify the presentation and will be relaxed in Chapter 6. Table 2.7 reports a detailed list of the National Allocation Plans (NAPs) by country and generator that we took directly from the Community Independent Transaction Log ([3]). If emissions of one generator exceed the initial allowance endowment, additional allowances have to be purchased on the market. Conversely, the company can sell the allowances in excess. For this reason, consumed allowances are truly opportunity costs since allowances consumed could have been sold. In accordance with the assumptions of our first stage analysis, these values refer to the EU-ETS "learning by doing" period (2005-2007). In sum, the distributed allowances amount to about 397 Mio ton p.a., which defines the emission cap of the power market in the period studied. As already discussed, allowance allocation methods can create economic distortions. Since our scope does not consists in modelling them, we assume that allowances are distributed once for all. This makes auctioning equivalent to grandfathering in terms of social benefit. This implies only a transfer of rents from public authorities to the owners of the installations covered by the EU-ETS. To the aim of completeness, we show the effects of both auctioning and grandfathering on generators' profit and then of the social welfare. We follow this approach in all models presented in the following Chapters. In accordance with our results,

[15]Since there is almost complete lack of information of demand response of energy intensive industries, we take as reference the value that Newbery adopted in his analysis ([35]).

generators face a significant cut of their profits when they have to buy allowances; but they gain a lot in the case where allowances are grandfathered. Note that these outcomes are in line with market evidences of the (2005-2007) period and with the discussion on windfall profits.

	Germany	**France**	**Belgium**	**Netherlands**	**Total**
EoN	35,798,149			7,698,528	**43,496,677**
Electrabel	351,107		9,296,495	7,749,596	**17,397,198**
Edf		23,540,828			**23,540,828**
EnBW	10,302,328				**10,302,328**
Essent				9,909,033	**9,909,033**
Nuon				9,109,160	**9,109,160**
RWE	112,482,413				**112,482,413**
Vattenfall	77,003,200				**77,003,200**
Fringe	72,384,875	11,709,252	5,764,115	4,283,146	**94,141,388**
tot	**308,322,072**	**35,250,080**	**15,060,610**	**38,749,463**	***397,382,225***

Table 2.7: NAPs by Generator and Country in Ton p.a. (2005-2007)

In Chapter 5, we investigate a market where generators may invest in new power stations. This represents the second stage of our analysis. Like in the first stage, we assess the EU-ETS indirect impact on energy intensive industries represented by their demand function.
Investments are in addition to the already existing facilities and we suppose that old and new plants have identical cost structure. In order to simplify our investment models and avoid economic distortions, we assume that new installations do not receive allowances for free. This is in line with the new ETS Directive proposed by the European Commission (see Figure 1.2). Furthermore, investments are not supported by any kind of subsidies[16]. Since, investment policy is a long-term strategy, we fix a global emission cap that is assumed to be aligned with the EU-ETS Second Phase (2008-2012). The carbon ceiling used under investment assumptions is lower than in the cases with fixed capacity. It amounts to about 359 Mio ton p.a. Again, it corresponds to the NAPs of the nine generators producing electricity in the country considered. Table 2.8 shows the details. These values are computed on the basis of the data reported in Table 2.7 by taking into account information provided by the European Commission for the period (2008-2012)[17].

Finally, in Chapter 6, we extend our models (both with and without investments) to the case where industries operate on the emission market. This represents the third stage of our study. Our objective is to analyze the combination of the direct and indirect impacts of the EU-ETS on the industrial sector. Modelling this assumption implies introducing modifications to *(1)* EIIs' energy price (and consequently of their electricity demand function), *(2)* the cap and *(3)* the emission constraint imposed on the market. We still measure the EU-ETS effects on EIIs by analyzing their power consumption variations. Industrial electricity demand is now affected by the combination of two prices: the pure electricity price (adopted in the previous models) and a carbon component obtained multiplying the allowance price by an industrial emission/allowance factor[18] that we calculate (see Tables 2.12 and

[16]Apart from those that, as already explained, renewable plants receive in Germany, in France and in Belgium. This choice has been forced by our input data.
[17]See $http://europa.eu/rapid/pressReleasesAction.do?reference=IP/07/1869\&format=HTML$.
[18]As we will explain in the following, we consider two different scenarios. For this reason, we denote these factors as "emission/allowance" since they differ per case study modelled.

	Germany	France	Belgium	Netherlands	Total
EoN	32,505,293	0	0	6,931,099	**39,436,392**
Electrabel	318,811	0	8,760,389	6,977,076	**16,056,276**
Edf	0	19,975,859	0	0	**19,975,859**
EnBW	9,354,679	0	0	0	**9,354,679**
Essent	0	0	0	8,921,249	**8,921,249**
Nuon	0	0	0	8,201,112	**8,201,112**
RWE	102,135,834	0	0	0	**102,135,834**
Vattenfall	69,920,140	0	0	0	**69,920,140**
Fringe	65,726,627	9,936,030	5,431,713	3,856,180	**84,950,549**
Total	**279,961,384**	**29,911,889**	**14,192,102**	**34,886,715**	***358,952,090***

Table 2.8: NAPs by Generator and Country in Ton p.a. (2008-2012)

2.13 respectively for (2005-2007) and (2008-2012) periods). Moreover, the new carbon ceiling has to account for the EIIs' NAPs. Tables 2.9 and 2.10 report these new NAPs respectively for our models without and with investment assumptions. They amount to about 790 Mio ton p.a. and 710 Mio ton p.a. respectively and correspond to the CO_2 ceilings in the first (2005-2007) and second (2008-2012) ETS phases. CTIL ([3]) provides the global NAPs by country reported in Table 2.9. The EIIs' NAPs are simply obtained by difference[19] as shown in Table 2.9. NAPs in Table 2.10 are instead the results of own computations based on information provided by the European Commission[20] and data reported in Table 2.9.

NAPS (2005-2007)			
	Total NAPs	**Power sector's NAPs**	**EIIs' NAPs**
Germany	494,979,063	308,322,072	186,656,991
France	150,400,000	35,250,080	115,149,920
Belgium	58,311,087	15,060,610	43,250,477
Netherlands	86,452,491	38,749,463	47,703,028
Total	**790,142,641**	**397,382,225**	**392,760,416**

Table 2.9: NAPs by Sector and Country in Ton p.a. (2005-2007)

NAPS (2008-2012)			
	Total NAPs	**Power Sector's NAPs**	**EIIs' NAPs**
Germany	449,448,925	279,961,384	169,487,540
France	127,623,770	29,911,889	97,711,881
Belgium	54,948,431	14,192,102	40,756,329
Netherlands	77,834,457	34,886,715	42,947,742
Total	**709,855,582**	**358,952,090**	**350,903,492**

Table 2.10: NAPs by Sector and Country in Ton p.a. (2008-2012)

Changing the modelling of the carbon market implies also a modification of the emission constraint

[19] Between the total NAPs and the power sector' NAPs we already computed.
[20] See $http://europa.eu/rapid/pressReleasesAction.do?reference = IP/07/1869\&format = HTML$.

that now includes also emissions from industries. Since we conduct our analysis by using an electricity demand approach, we assume that industrial emissions are proportional to their power consumptions. We know, in fact, that these sectors are energy intensive and thus their electricity need depends on their production level. Their global emissions are then determined by multiplying their electricity demand (that is an endogenous variable) by a corresponding emission factor. Due to the lack of information, we compute these emission factors on an aggregated level. In other words, we distinguish them per country but not per production sector. They are assumed to be identical in the two EU-ETS phases and correspond to the values listed in the first column of Tables 2.12 and 2.13.

EMISSIONS (2005)			
	Total Emissions	**Power Sector's Emissions**	**EIIs' Emissions**
Germany	473,715,872	295,077,247	178,638,625
France	131,147,095	28,756,797	102,390,299
Belgium	55,354,096	19,562,993	35,791,103
Netherlands	80,351,292	51,433,542	28,917,750
Total	**740,568,355**	**394,830,578**	**345,737,777**

Table 2.11: Power Sector and EIIs' Emissions in Ton p.a. (2005)

Moreover, we consider two case studies. In a first scenario, we assume that industries operate in the emission market but do not receive any free allowance. In Tables 2.12 and 2.13, we refer to this model as "EIINA". We then change this assumption and we suppose that energy intensive industries receive subsidies in form of free allowances to compensate for the direct and indirect burdens caused by the EU-ETS. We denote this model as "EIIA". As already said, the modelling of the direct EU-ETS costs on EIIs implies an addition of a carbon component to the industrial electricity price that is obtained by multiplying the allowance price by industrial emission/allowance factors. In the "EIINA ", we have "pure" emission factors since industries do not receive free allowances. They result from the division of the EIIs' 2005 emissions[21] in Table 2.11 with respect to EIIs' annual reference demand (obtained by multiplying the values in Table 2.5 by 8760). These EIIs' emission factors are identical in both ETS commitment periods (see Tables 2.12 and 2.13), but differ per country. We also use them to compute the industrial emission in the emission constraint both in the "EIINA" and "EIIA" cases.

	FACTORS	
	EIINA	**EIIA**
Germany	0.69	-0.03
France	0.63	-0.08
Belgium	0.66	-0.14
Netherlands	0.53	-0.35
Total	**0.65**	**-0.09**

Table 2.12: Industrial Emission and Allowance Factors by Country in Ton/MWh (2005-2007)

In the "EIIA" case, these factors account for the subsidies that industries receive in form of free allowances (see Tables 2.12 and 2.13). Consequently, we refer to them as industrial "allowance"

[21] CTIL ([3]) is the reference for 2005 emissions. Note that CITL also lists the emissions of the installation covered by the EU-ETS. Again, we compute the EIIs' emissions by difference between the total national emissions and the power sector emissions that we determine by accounting for those installations included in our power sector' NAPs.

	FACTORS	
	EIINA	**EIIA**
Germany	0.69	0.04
France	0.63	0.03
Belgium	0.66	-0.09
Netherlands	0.53	-0.26
Total	**0.65**	**-0.09**

Table 2.13: Industrial Emission and Allowance Factors by Country in Ton/MWh (2008-2012)

factors. They are computed dividing the difference between industrial emission in 2005 (see Table 2.11) and the allowance that they receive for free in each ETS phase (see respectively Tables 2.9 and 2.10) by their annual reference demand in 2005 (see Table 2.5). Note that, in the (2005-2007) phase, industries were long on emission market and this implies negative factors. Moreover, they differ per ETS commitment period since in the (2008-2012) period the distribution of free allowances is more restrictive.

2.2 Mathematical Background: Variational Inequalities, Quasi Variational Inequalities and Complementarity Conditions

Mathiesen ([32]) introduced complementarity problems (CPs) as a general computational method for solving economic general and partial equilibrium models. Our models are all formulated in complementarity conditions. CPs arise in a variety of disciplines including engineering and economics and can be applied to models where we might want to compute Walrasian equilibrium or optimization problems where we can model the first order conditions for nonlinear programs. Other examples may be bimatrix games and option pricing (Ferris ([7]) and the references therein). Complementarity based models are extensively used to model power market as explained by Hobbs and Helman ([28]).

In our specific case, the introduction of the average cost power contracts induce us to adopt this particular mathematical formulation. Perfect competition is usually modelled by using a profit/surplus maximization problem that it is not possible to apply to the cases with average cost prices. In fact, profit/surplus maximization problem assumes a marginal cost pricing system and we depart from this hypothesis at least for modelling the EIIs sector. For this reason, we adopt a complementarity approach[22]. As we will explain in Chapters 3 and 5, when average cost based prices are applied, generators' optimization problem changes. They no longer maximize their profits, but minimize their production costs by taking into account that the two consumers groups are priced in different ways. This leads to a Quasi-Variational Inequality (QVI) problem that thanks to our model assumptions can be transformed into a Variational Inequality (VI) problem. This VI problem is then expressed in complementarity conditions (see Chapter 3).

[22] Note that, as already explained, our reference model defines a perfectly competitive. In this case, the problem can be also formulated and solved as an optimization model. The implementation of the complementarity and the corresponding optimization problems leads to identical results.

2.2.1 Variational Inequality Problems (VIs) and Complementarity Problems (CPs)

In this Section, we define VIs and then we describe their relation with complementarity and quasi-variational problems. The variational inequality problem encompasses several mathematical problems, including nonlinear programs, optimization problems, complementarity and fixed point problems. Facchinei and Pang ([23]) and Nagurney ([34]) define variational inequalities as follows:

Definition 1 *(Nagurney [34]) The variational inequality problem $VI(F,K)$ is to determine a vector $x^* \in K \subset R^n$, such that:*

$$F(x^*)^T(x - x^*) \geq 0 \quad \forall\ x\ \in K \tag{2.1}$$

where F is a given continuous function from K to R^n and K is a given closed and convex set.

In geometric terms, the variational inequality (2.1) states that the vector $F(x^*)^T$ must be at acute angle with all the vectors emanating from x^*.

Nagurney ([34]) explains that, if certain conditions are satisfied, both unconstrained and constrained optimization problem can be formulated as $VI(F,K)$ problems. In particular, the two subsequent Propositions define the relationship between these two classes of problems.

Proposition 1 *(Nagurney [34]) Let x^* be a solution to the optimization problem:*

$$\textbf{Min}\ \ f(x) \tag{2.2}$$

$$subject\ \ to\ \ x \in K$$

where f is continuously differentiable and K is closed and convex. Then x^* is a solution to the variational inequality problem:

$$\nabla f(x^*)^T \cdot (x - x^*) \geq 0 \quad \forall\ x \in K$$

Proposition 2 *(Nagurney and [34]) If $f(x)$ is a convex function and x^* is a solution to $VI(\nabla f, K)$, then x^* is a solution to the optimization problem (2.2)*

In his paper ([26]), Harker argues that, accounting for these results, Loins and Stampacchia in 1967 recognized that a $VI(F,K)$ can be cast as a Nash equilibrium problem where the set X is represented by the full Cartesian product of players' strategies. Specifically, consider a finite set N of n players in the market. We assume that $K^i \subseteq R^m$ is the strategy compact and convex set of player i; $K = \prod_{i\in N} K^i \subseteq R^{nm}$ is the full Cartesian product of the strategy sets X and finally $X^{N\backslash i} = \prod_{j\in N, j\neq i} X^j$ is the full set X minus the *i-th* player's feasible region. Finally, let the utility function of each player i be defined by $u^i : X \longrightarrow R$ that is a concave and one continuously differentiable in X. If all these conditions holds, one has that the following maximization problem:

$$\textbf{Max}\ \ u^i(x^i, x^{N\backslash i}) \tag{2.3}$$

$$with\ \ \ x^i \in K^i$$

where the Nash Equilibrium is a vector x^*:

$$x^* = (x^{1*}, ..., x^{n*}) \in K$$

such that:

$$u^i(x^{*i}, x^{*N\backslash i}) \geq u^i(x^i, x^{*N\backslash i}) \quad \forall\ x^i \in K^i, \forall i,$$

where $x^{*N\backslash i} = (x^{*1}, ..., x^{*i-1}, x^{*i+1}, ...x^{*n})$

This optimization problem can be reformulated as:

$$-\nabla_{x^i} u^i(x^{*i}, x^{*N\backslash i})^T (x^i - x^{*i}) \geq 0 \qquad \forall x^i \in K^i \tag{2.4}$$

The VI problem simply results from the sum over all i of conditions expressed in (2.4). The functions F^i corresponds to the gradient map of the utility function u^i. Problem (2.4) can be rewritten in the standard VI form where $F(x^*) = (F^1(x^*)^T, F^2(x^*)^T, ...F^n(x^*)^T)$:

$$F(x^*)^T (x - x^*) \geq 0 \qquad \forall x\ \in K$$

The variational inequality problem also contains the complementarity problem as a special case. Complementarity problems are defined on convex cone that generally is represented by R^n_+. The definition of CPs is as follows:

Definition 2 *(Facchinei and Pang [23]) Let R^n_+ denote the nonnegative orthant in R^n. Given a continuous function $F : R^n_+ \to R^n$, the CP is to find a vector $x^* \in R^n$ such that:*

$$0 \leq F(x^*)\ \perp\ x^* \geq 0 \tag{2.5}$$

The use of the term “complementarity” derives from the concept of orthogonality ($\perp$) stated in the definition. In other words, solving a CP consists in finding $x^* \geq 0$ such that:

$$F(x^*) \geq 0 \qquad and \qquad F(x^*)^T \cdot x^* = 0 \tag{2.6}$$

Condition (2.5) is the compact form we adopt for the CP formulation of our models. Geometrically, the complementarity problem involves finding a nonnegative vector x^* such that the image $F(x^*)$ is also nonnegative and orthogonal to x^*. When $F(x)$ is nonlinear, CP is called a *nonlinear complementarity problem (NCP)*. If $F(x)$ is an affine function, i.e. $F(x) = Mx + q$, then CP is termed a *linear complementarity problem (LCP)*. It is also possible to have *mixed complementarity problem (MCP)*. Let y be a second vector of variables and $G(x, y)$ be a vector valued function with the same dimension as y. A (MCP) can be stated as finding x^*, y^* such that:

$$0 \leq F(x^*, y^*)\ \perp\ x^* \geq 0$$

$$G(x^*, y^*) = 0$$

The CP described in (2.5) defines a *square* system where nonnegative variables are as many as nonnegative equations. It implies a correspondence one to one between variables and complementarity conditions. Complementarity based models offer a natural approach to construct equilibrium model.

A market comprises different agents that produce, trade and consume different commodities. Standard microeconomic theory suggests to represent each agent by an optimization problem (profit or surplus maximization). Complementarity models readily derive from this principle. Complementarity-based formulations are created by first writing the Karusk-Kunt-Tacker (KKT) conditions of the maximization problems of the agents included in the models studied[23] and, then, adding market equilibrium conditions[24]. Let a constrained optimization problem be stated as follows:

$$\textbf{Min} \;\; F(x) \tag{2.7}$$

subject to:

$$G(x) \geq 0 \quad x \geq 0$$

where $F(x)$ is the objective function to be minimize. Let us assume that $F(x)$ is smooth and convex and each G_i^x is smooth and concave. The KKT conditions defines a set of complementarity conditions whose solution $\{x^*, \lambda^*\}$ is also a (global) optimal solution to the minimization problem (2.7) and vice versa since, under the above assumptions, KKTs are necessary and sufficient conditions for optimality. In particular, the CP associated with the optimization problem (2.7) is as follows:

$$0 \leq \partial F/\partial x_i - \sum_j \lambda_j G_j/\partial x_i \perp x_i \geq 0$$

$$0 \leq G_j \perp \lambda_j \geq 0$$

The relationship between the complementarity problem and the variational inequality problem is as follows:

Proposition 3 *(Nagurney [34]) $VI(F, R_+^n)$ and (2.5) have precisely the same solution, if any.*

Due to the equivalence of the complementarity problem and the variational inequalities, most of the existence results for complementarity problem are based on the corresponding existence results for variational inequality. However, the domain of complementarity problem is always unbounded since it is a cone, whereas the domain of variational inequality is not necessarily unbounded. Consequently, we refer to VI properties to find existence results for complementarity solutions. In their survey on variational inequalities and complementarity problems, Harker and Pang ([25]) argue that Karamardian who was the first to establish the relationship presented in Proposition 3 between VI and CPs. However, every nonlinear complementarity problem is a variational inequality problem, but the converse is not true in general. Only when some particular conditions on the set X hold then a $VI(F, X)$ problem can be converted into a CP. In particular the set X has to be defined as follows:

$$X = \left\{x \in R_+^n : g_i(x) \leq 0, i = 1, 2, ..., m; h_j(x) = 0, j = 1, 2, ..., p\right\} \tag{2.8}$$

and $g_i : R^n \to R^m$ and $h_j : R^n \to R^p$ are continuously differentiable functions and satisfy the standard constraint qualification of the type often imposed in nonlinear programming.

The existence of a solution to a variational inequality problem $VI(F, K)$ follows from continuity of the function F defining the variational inequality, provided that the feasible set K is compact. More formally:

[23] In our models, generators and consumers.

[24] In our models, Emission and transmission constraints and equilibrium on energy, emission and transmission markets.

Theorem 1 *(Nagurney [34]) If K is a compact and convex set and $F(x)$ is continuous on K, then the variational inequality problem admits at least one solution x^*.*

If the compactness assumption of the set K holds, then the uniqueness of the solution x^* of a variational inequality $VI(F,K)$ is guaranteed when the function $F(x)$ is strictly monotone. In particular,

Theorem 2 *(Nagurney [34]) Suppose that $F(x)$ is strictly monotone on K. Then the solution is unique, if one exist.*

In the case where the set K is not compact, existence of a solution to a variational inequality problem can be established under the coercivity condition of the function $F(x)$ as indicated in subsequent theorem:

Theorem 3 *(Nagurney [34], Corollary 1.2) Suppose that $F(x)$ satisfies the coercivity condition*

$$\frac{(F(x) - F(x_0))^T \cdot (x - x_0)}{||x - x_0||} \to \infty$$

as $||x|| \to \infty$ for $x \in K$ and for some $x_0 \in K$. Then the $VI(F,K)$ always has a solution.

The following theorem provides a condition under which both existence and uniqueness of the solution to the variational inequality problem are guaranteed. There is no assumption on the compactness of the feasible set K.

Theorem 4 *(Nagurney [34]) Assume that $F(x)$ is strongly monotone. Then there exists precisely one solution x^* to $VI(F,K)$.*

2.2.2 Quasi-Variational Inequality Problems ($QVIs$)

A quasi-variational inequality problem is a variational inequality problem where the defining set of the problem $K(x)$ varies with the variable x. The classic definition of a QVI problem is:

Definition 3 *(Harker [26]) Let K be a point to set map mapping from R^n into a subsets of R^n, that is, for every $x \in R^n$, $K(x)$ is a subset of R^n. The QVI defined by the pair $QVI(F,K)$ is to find a vector $x^* \in K(x^*)$ such that:*

$$F(x^*)^T(x - x^*) \geq 0 \quad \forall\ x\ \in K(x) \tag{2.9}$$

According to Harker ([26]), a QVI problem can be used to represent a generalized Nash game where players can affect the feasible strategy set of the other players. A generalized Nash equilibrium (GNE) can be defined as follows. Let N be the set of n players, where n is finite, and $X^i \subseteq R^m$ is the strategy set of players i that it is assumed to be compact and convex. The full Cartesian product of the strategy set is represented by $X = \Pi_{J \in N} X^j$ while $X^{N \setminus i} = \Pi_{J \in N, j \neq i,} X^j$ is the full set minus the $i-th$ player's feasible region. $K^i : X^{N\setminus i} \to X^i$ is a point to set mapping which represents the ability of players $j \neq i$ to affect the feasible strategy of player i. This is equivalent to $K^i \subseteq R^m \quad \forall x \in K$.

Finally, let the utility for player i be represented by the function $u^i : K^i \rightarrow R$, where is defined as above. The generalized Nash equilibrium of the game is thus defined as a point $x^* = (x^{*1}, x^{*2}, ..., x^{*n}) \in K$ such that:

$$x^{*i} \in K^i(x^{*N\setminus i}) \qquad \forall\ i\ \in N,$$

$$u^i(x^*) \geq u^i(x^i, x^{*N\setminus i}) \qquad \forall\ x^i\ \in K^i(x^{*N\setminus i}) \qquad i \in N$$

This generalized Nash equilibrium can be espressed in QVI form by replacing K^i with $K(x^{N\setminus i})$ in (2.3) and (2.4). Recall that $K^i : x^{N\setminus i} \longrightarrow X^i$ is a point to set map which represents the ability of player $j \neq i$ to influence the feasible strategy set X^i of player i. The QVI of the GNE is then defined as follows:

$$-\nabla_{x^i} u^i(x^{*i}, x^{*N\setminus i})^T(x^i - x^{*i}) \geq 0 \quad \forall\ x^i \in K^i(x^{*N\setminus i}) \subseteq X^i \tag{2.10}$$

and the more compact form is:

$$F(x^*)^T(x - x^*) \geq 0 \quad \forall\ x\ \in K(x^*) \subseteq X \tag{2.11}$$

where again $F(x^*) = (F^1(x^*)^T, F^2(x^*)^T, ...F^n(x^*)^T)$.

Harker ([26]) presents an existence result for the solution to a quasi-variational problem that he took it directly from a paper by Chan and Pang (1982).

Theorem 5 *(Harker [26], Theorem 2) Let F and K be respectively a point to point and a point to set mapping from R^l into itself. Suppose that there exists a nonempty compact convex set X such that:*

(i) $K(x) \subseteq X \quad \forall\ x \in X$

(ii) *F is continuous on K;*

(iii) *K is a nonempty, continuous, closed and convex valued mapping on X. Then there exists at least a solution to the QVI problem in Definition 3*

Moreover, Harker ([26]) proves that there exists a relationship between the solutions to a variational and quasi-variational problems. He shows several results but we report only those that are necessary to the aim of our analysis.

Theorem 6 *(Harker [26], Theorem 3) Let F and K be respectively a point to point and a point to set mapping from R^l into itself. Suppose that there exists a nonempty compact convex set X such that:*

(i) $K(x) \subseteq X \quad \forall\ x \in X$ *and*

(ii) $x \in K(x) \quad \forall\ x \in X$

Then any solution to the variational inequality defined with the function F over the set K is a quasi-variational inequality solution, but the converse is not true in general.

Generally, a quasi-variational problem is characterized by a plurality of solutions and its solution set includes the solutions to the associated variational inequality problem.

Theorem 6 implies that the proof of the existence of QVI solution follows immediately from the proof of the existence of a VI solutions. This means that standard results in VI literature can be applied also to QVI problems. This reasoning holds not only for the existence results, but also for solution techniques and algorithm.

However, Harker ([26]) proves that, under particular conditions, the VI solutions are the only points in the set of solutions to the QVI over $K(x)$ (see Harker [26] Theorem 6 for more details).

2.3 Application of Complementarity Conditions to the Electricity Market

In this Section, we illustrate how complementarity conditions can be applied to energy market problems. This may improve the understanding of the models described in the following Chapters of this thesis. Note that both perfectly and imperfectly competitive (like Cournot) markets can be formulated in complementarity form. However, we analyze only the competitive market problem since it represents the starting point of our average cost pricing models.

In perfect competition, all players[25] are price-takers and maximize their surplus. Power is traded in order to guarantee the balance between supply and demand. We follow the approach adopted by Hobbs and Helman ([28]). We first define the optimization problems of each player and then we compute their KKT conditions whose combination results in a complementarity model. The presence of the energy balance constraint makes the complementarity problem mixed. Note that in perfect competition, each optimizer considers p_i as fixed to its optimization problem. This because it is not possible to excise market power.

Generators

Generators f maximize their profits from selling power at node i, given the power price p_i.

$$\textbf{Max} \;\; p_i \cdot s_{fi} - C_{s_{fi}}(x_{fi}) \tag{2.12}$$

subject to

$$G_{s_{fi}}(s_{fi}, x_{fi}) \geq 0 \quad (\mu_i)$$

$$x_{fi}, s_{fi} \geq 0$$

where p_i is the nodal electricity price; s_{fi} and x_{fi} respectively indicate the power sold and produced by generator f in each node i. $C_{s_{fi}}(x_{fi})$ represents the total costs faced by generator f of using x_{fi} to produce s_{fi} at node i. Finally, $G_{s_{fi}}$ is the constraint set for generator f at node i. This may represent one or several constraints. Usually, power companies have to account for production balance (electricity generated should be greater or equal to the electricity sold) and plant capacity constraints. Dual variables μ_i associated with constraints $G_{s_{fi}}$ are marginal costs resulting from the production of electricity. As we will explain in the following Chapters these dual variables can represent generation

[25] In our case, they are generators, consumers and Transmission System Operator (TSO).

and capacity marginal costs. They meaning varies with respect to the constraint they pair. Moreover, electricity produced (x_{fi}) and sold (s_{fi}) must be nonnegative.
Assuming that the objective function is smooth and concave and the constraints are smooth and convex, the associated KKT conditions define an optimal solution to the following complementarity problem:

$$0 \leq s_{fi} \perp (p_i - \mu_{fi} \cdot \partial G_{s_{fi}} / \partial s_{fi}) \leq 0$$

$$0 \leq x_{fi} \perp (-\partial C_{s_{fi}} / \partial x_{fi} - \mu_i \cdot \partial G_{s_{fi}} / \partial x_{fi}) \leq 0$$

$$0 \leq \mu_{fi} \perp G_{s_{fi}} \leq 0$$

Consumers

Each consumer located in i demand d_i with the intention of maximizing his surplus for a given electricity price p_i.

$$\textbf{Max} \;\; B_i(d_i) - p_i \cdot (d_i) \tag{2.13}$$

subject to

$$d_i \geq 0$$

where $B_i(d_i)$ corresponds to the consumers' willingness to pay. This is approximated by the integral of the demand curve $P_i(d_i)$ from $d = 0$ to $d = d_i$. Recall that p_i is the power price and that the quantity of electricity demanded d_i must be positive. The associated complementarity conditions are :

$$0 \leq d_i \perp (P_i(d_i)) - p_i \leq 0$$

As already said, $P_i(d_i)$ is demand function corresponding to the derivative of the integral of the willingness to pay $B_i(d_i)$.

Transmission System Operators (TSO)

Transmission System Operator relieves the network and makes profit from delivering electricity from node i to another node j. It maximizes the following optimization problem:

$$\textbf{Max} \;\; p_j \cdot t_{Iij} - p_i \cdot t_{Eij} - C_{Tij}(t_{Eij}, t_{Iij}) \tag{2.14}$$

subject to

$$G_{Tij}(t_{Eij}, t_{Iij}) \leq 0 \;\; (\theta_{ij})$$

$$t_{Eij}, t_{Iij} \geq 0$$

We assume that the TSO buys electricity in one node i of the network to resell it in another location j. Note that we use both j and i to refer to the nodes of the network. Therefore p_j and p_i

are two nodal prices. The positive variables t_{Iij} and t_{Eij} indicate respectively the electricity imported and exported. More precisely, t_{Iij} represents the amount of energy transported to j by the TSO which originates an export from i. The variable t_{Eij} has a similar meaning. It corresponds to the energy removed from i and delivered to j by the TSO. In other words, $p_j \cdot t_{Iij} - p_i \cdot t_{Eij}$ illustrates the arbitrage conducted by the TSO: it buys electricity from node i at a certain price p_i and then sells it to node j at another price p_j. In doing that, the TSO accounts for the physical constraints of the network. These are represented by $G_{Tij}(t_{Eij}, t_{Iij})$ which indicate that the total power flow along lines must not excess their capacities. Network constraints are paired with θ_{ij} that are the transmission costs. They arise when the grid is congested and usually are paid by electricity consumers. Finally, the TSO faces also some costs, represented by $C_{Tij}(t_{Eij}, t_{Iij})$, which concern the maintenance and the construction of transmission capacity.

The corresponding complementarity conditions are:

$$0 \leq t_{Eij} \perp (-p_i - \partial C_{Tij}/\partial t_{Eij} - \theta_{ij}\partial G_{Tij}/\partial t_{Eij}) \leq 0$$

$$0 \leq t_{Iij} \perp (p_j - \partial C_{Tij}/\partial t_{Iij} - \theta_{ij}\partial G_{Tij}/\partial t_{Iij}) \leq 0$$

$$0 \leq \theta_{ij} \perp G_{Tij} \leq 0$$

As already anticipated in Section 2.1.1, our network representation accounts for the $PTDF$ approach. Its functioning will be shown in Chapters 3 and 5. This particular approach leads to a nodal price system where electricity prices directly include the transmission charges resulting from a grid congestion. Moreover, generators and consumers' optimal choices are influenced by transmission constraints that impose a global restriction on the market. However, we do not explicitly model the TSO's optimization problem, but we take into account for its merchandising profit in the computation of the welfare (see Chapters 4 and 5). We present it here only for the sake of completeness.

Market Balance

The market balance accounts not only for the electricity demanded and supplied respectively by consumers and generators; but also for the injections and the withdrawals operated by the TSO. The results is as follows:

$$d_i - \sum_f s_{fi} - \sum_{j \in I(i)} t_{ij} + \sum_{j \in E(j)} t_{Eij} = 0 \ \ (p_i)$$

The combination of all players' complementarity conditions in addition with the market clearing condition leads to a square MCP. Note that the energy market balance constraint is implicitly matched with the electricity price p_i.

Since not all readers are familiar with these mathematical instruments, we presents our models both as optimization and as complementarity condition problems. The complementarity conditions of our models are implemented in GAMS adopting the solver PATH as illustrated by Dirkse and Ferris ([7]). PATH is a generalization of Newton's method that can be applied to systems of nonsmooth equations. Nonsmooth equation arise in a number of mathematical programming applications like reformulations of variational inequalities and complementarity problems. In fact, PATH is considered as the most effective technique currently available for solving economic equilibrium problem.

2.4 Some Additional Mathematical Insights of our Models

In all scenarios considered, our reference models are convex and have one global solution. The introduction of average cost based contracts may lead to computational difficulties since the averaging process ruins the convexity properties of the model.

In our analysis, we introduce both a nodal and a single average cost pricing characterized by different complexity. In particular, the single average transmission cost is based on a product of primal ($g^1_{f,i}$, d^1_i) and dual variables ($\mu^{t,+}_l$, $\mu^{t,-}_l$) both in the case with fixed capacity ($ptrans^1$) and investments ($inv_p trans^1$). Such a kind of model belongs to the NP-hard problems. This makes the single average cost model more complex than the nodal average cost one which includes only primal variables. This holds in all the models with average cost prices.

Generally, a non-convex problem may have a multiplicity of solutions or do not have any solution. In this thesis, we do not consider the theoretical aspect of such a kind of problem because our approach is purely empirical.

Our simulations show that all models give results, apart from one difficult case in Chapter 6 that is not feasible. However, we notice some strange behaviour in the allocation of old (Chapters 4) and new (Chapters 5) capacities among nodes and consumer groups in the average cost models. These results change when one modifies the starting point used to implement the models. This means that non-convexity leads to disjoint solutions. This happens in all the cases studied (with and without investments; with and without the modelling of the direct EU-ETS impact). The infeasible problem in Chapter 6 has no solutions even changing the starting point.

We will show a sample of these alternative results in Sections 4.6 and and 5.7 of Chapters 4 and 5 respectively. In order to avoid redundancy, we do not report the alternative solutions of the models in Chapter 6.

Chapter 3

Modelling Average Cost Based Contracts under Fixed Capacity Assumptions

3.1 Introduction

The inception of the Emission Trading System in Europe (EU-ETS) has increased power price. This affects the competitiveness of electricity intensive industrial consumers and may induce them to leave Europe. As already discussed in the Introduction, we take up a proposal of the Energy Intensive Industries (EIIs) and we explore the possible application of special contracts, based on the average cost pricing system, which would mitigate the impact of CO_2 cost on their electricity price. The models here presented suppose fixed generation capacities. Chapter 5 treats the case with capacity expansion.

We first consider a reference situation of a perfectly competitive market where electricity generating companies supply all consumers (N-EIIs and EIIs). They are assumed to be price-takers and buy electricity at the short-run marginal cost of the last running plant. In this first reference model, generators apply identical prices to both consumer groups. The perfectly competitive energy market is complemented by equally perfectly competitive zonal transmission and CO_2 allowance markets. An emission constraint is imposed on energy market in order to determine the allowance price and then the indirect impact, through electricity prices, of the application of the EU-ETS on large industries and on the rest of the market. In this Chapter, we neglect the direct effect (that is through charging for emissions).

We then recognize that electricity intensive users require a different electricity service: the bulk of their demand is indeed long-term and high load. They are also in a position to finance the construction and the operation of large generation units. We therefore consider an alternative organization of the electricity market whereby part of the existing capacities is dedicated only to industries. This allows industries to have all the power units needed to cover their electricity demand under special contracts. Consequently, their electricity prices are based on average costs defined in the contract: this duality of pricing schemes (marginal cost through perfect competition and average cost through contracts) is the innovative aspect that we want to study.

Our methodology is structured into two steps: in a first scenario, we consider a single average price system whereby industrial consumers can purchase power at the same price in any location. The implicit assumption on which this pricing approach relies is that these industrial consumers constitute a power purchase consortium that buys power from plants located in different nodes of the network (like Exeltium, see Chapter 1). As a second step, we modify the single average cost model assuming that industries can conclude special contracts with local generators. In this case, industrial consumers clear their demand with the electricity produced inside the node where they are located. Therefore, they do not have to pay transmission costs, since they are directly connected with generators. The backside effect of these nodal average cost based contracts is the technological constraint to which industries are subject. It implies that the nodal average cost prices are affected by the fuel mix adopted in each node. In both cases, we assume that industrial consumers have a constant electricity consumption over time. Moreover, emission and transmission constraints are still included. The application of the single and the nodal average cost systems implies market segmentation and capacity splitting between EIIs and N-EIIs. These are still priced at marginal cost.

We formulate the optimization problems of the different market players (generators, N-EIIs and EIIs) in complementarity condition form. In order to make these models more understandable, we first present them in the "standard" optimization form and then we transform them in complementarity conditions. Finally, the analysis of these problems is conducted with simulation models applied to the Central Western European market (see Figure 2.1 in Section 2.1). We assume to model the first EU-ETS period (2005-2007). The equilibrium models developed are implemented in the GAMS environment and results are discussed in Chapter 4.

3.2 Basic Model without Emission Constraint

A perfectly competitive market is classically modelled by maximizing the sum of consumers and generators' surpluses. Alternatively, it can be modelled as a set of optimization problems where each agent maximizes its surplus for given prices and a set of market clearing conditions at these prices. We use the latter approach that we also explained in Section 2.3.

The present section specifies the equations and constraints included in the basic models. We first present the maximization problem of generators, followed by the analysis of the consumers' optimization model. We conclude with the description of the network constraints. The emission constraint will be introduced in Section 3.3. We recall that the model accounting both for emission and transmission constraints is assumed to be our reference case. In order to identify the two cases of perfectly competitive markets we introduce these labels: "NETS_R" (no environmental regulation) and "ETS_R" (adoption of ETS policy).

3.2.1 Notation of the Perfect Competition Models

This section lists the variables (primal and dual) and the parameters included in the two variants of the basic model.

A. **Indexes and Sets**

- $i \in I$ Set of active nodes in the transmission network;

- $f \in F$ — Set of firms producing electricity (generators);
- $m \in M$ — Set of technologies used to produce electricity;
- $l \in L$ — Set of lines composing the transmission grid;
- $c \in (1, 2)$ — Set of consumer group considered. They are respectively EIIs "*1*" and N-EIIs "*2*";
- $t \in (s, w)$ — Set of periods modelled. They are respectively the summer "s" and the winter "w" periods.

B. **Variables**

Generators

- $g^t_{f,i}$ — Hourly power sold at node i by generator f in each period t in MW;
- $gp^t_{f,i,m}$ — Hourly generated electricity by unit m owned by generator f at node i in each period t in MW;
- $\nu^t_{f,i,m}$ — Dual variable representing the marginal capacity cost (scarcity rent) of generator f, defined by node i and technology m in each period t;
- $\eta^t_{f,i}$ — Dual variable representing the marginal production cost by generator f and node i in each period t.

Consumers (EIIs and N-EIIs)

- $d^{t,1,2}_i$ — Hourly MW of power demanded respectively by EIIs "*1*" and N-EIIs "*2*" located at node i in each period t;
- $P(d^{t,1,2}_i)$ — Inverse demand function representing the EIIs "*1*" and the N-EIIs' "*2*" willingness to pay in each period t.

Electricity Prices

- p^t_i — €/MWh price of electricity at node i in each period t;
- $phub^t$ — €/MWh price of electricity set at the hub node in each period t;
- α_i — Dual variable related to the constraint imposing the equality of the hourly industrial electricity consumption of the two periods.

EU-ETS

- λ — Allowance price in €/ton.

Network

- $\mu_l^{t,+,-}$ Dual variables corresponding to the congestion costs of line l; depending on i and flow direction (+,-) in each period t.

C. **Parameters**

Generators

- $G_{f,i,m}$ Capacity (in MW) of plant type m owned by generator f at node i;
- $cost_{f,i,m}$ Marginal costs in €/MWh of unit m owned by generator f at node i.

Consumers (EIIs and N-EIIs)

- $a_i^{t,1}$ EIIs' demand function intercept at node i and period t;
- $b_i^{t,1}$ Slope of the EIIs' demand function elasticity at node i and period t;
- $a_i^{t,2}$ N-EIIs' demand function intercept at node i and period t;
- $b_i^{t,2}$ Slope of the N-EIIs' demand function elasticity at node i and period t.

EU-ETS

- E_f Amount of free allowance by generator f;
- CAP Total emission cap of the power market analyzed;
- em_m Emission factor depending on technology m used.

Network

- $PTDF_{l,i}$ Power Transfer Distribution Factor matrix depending on line l and node i;
- $Linecap_l$ MW limit of flow through line l (line capacity2).

Period durations

- $hour^t$ Duration in hours of each period t;
- $proportion^t$ Proportion of duration of each period t in the year.

3.2.2 Generators' Profit Maximization Model

Each generator f wants to optimize its annual profit (3.1) for given electricity and transmission prices for delivering electricity to the hub. The profit function therefore accounts for the production costs and transmission charges. In this perfectly competitive model, all electricity is traded at the hub implying that generators only pay transmission charges to the hub or, in other words, that the price received by generators at node i is equal to the price at the hub minus the transmission charges from the node to the hub.

Since in this initial model there is no market contractual segmentation of the market into EIIs and N-EIIs, the variables indicating respectively the electricity produced $gp^t_{f,i,m}$ and sold $g^t_{f,i}$ by each generator f do not depend on consumer group. The profit maximization problem of each generator f is accordingly stated as:

$$\textbf{Max} \sum_{t,i} p^t_i \cdot g^t_{f,i} \cdot hour^t - \sum_{t,i,m} cost_{f,i,m} \cdot gp^t_{f,i,m} \cdot hour^t \tag{3.1}$$

subject to:

$$0 \leq g^t_{f,i} \leq \sum_m gp^t_{f,i,m} \qquad (\eta^t_{f,i}) \quad \forall\, t, f, i \tag{3.2}$$

$$0 \leq gp^t_{f,i,m} \leq G_{f,i,m} \qquad (\nu^t_{f,i,m}) \quad \forall\, t, f, i, m \tag{3.3}$$

Let p^t_i be the electricity price at node i and period t and $\sum_{t,i} p^t_i \cdot g^t_{f,i} \cdot hour^t$ be the annual revenues earned by generators. Generator f's net profit is obtained subtracting the annual production cost $\sum_{t,i,m} cost_{f,i,m} \cdot gp^t_{f,i,m} \cdot hour^t$ from the revenues accruing at the different nodes. The electricity generating process is subject to two main constraints: the periodic production condition (3.2) and the capacity constraint (3.3).

Production condition (3.2) states that in each hour the global amount of electricity produced has to be greater or equal the total quantity sold. This holds for each generator f. This constraint is matched with the dual variable $\eta^t_{f,i}$ indicating the generators' marginal generation cost at the node i in the period t.

Since each power plant has limited capacity, we introduce the capacity constraint (3.3). This means that the electricity $gp^t_{f,i,m}$ produced by generator f with plant m in node i must not exceed the plant m capacity $G_{f,i,m}$. This holds in each period t. This condition is matched with the dual variable $\nu^t_{f,i,m}$, which represents the scarcity rent of capacity. The scarcity rent can be interpreted as the difference between the electricity sale price and the unit cost. Its value depends on the electricity price that corresponds to the fuel cost[1] of the last technology run to produce electricity: this is a direct implication of the staircase structure of the supply curve[2]. It is positive when plants m are run at their full capacity.

The optimization problem (3.1)-(3.3) can be easily transformed in complementarity conditions[3]. Following this alternative approach, one has the following new conditions (see (3.4)-(3.7)):

---

[1] If an environmental policy is implemented, then the electricity price accounts also for the carbon cost associated with the plant.

[2] See Section 2.1.2 in Chapter 1.

[3] Note that we consider a minimization version of the optimization problem presented above to write complementarity conditions.

$$0 \leq -p_i^t + \eta_{f,i}^t \perp g_{f,i}^t \geq 0 \quad \forall\, t, f, i \tag{3.4}$$

$$0 \leq cost_{f,i,m} + \nu_{f,i,m}^t - \eta_{f,i}^t \perp gp_{f,i,m}^t \geq 0 \quad \forall\, t, f, i, m \tag{3.5}$$

$$0 \leq G_{f,i,m} - gp_{f,i,m}^t \perp \nu_{f,i,m}^t \geq 0 \quad \forall\, t, f, i, m \tag{3.6}$$

$$0 \leq \sum_m gp_{f,i,m}^t - g_{f,i}^t \perp \eta_{f,i}^t \geq 0 \quad \forall\, t, f, i \tag{3.7}$$

Note that the complementarity problem (3.4)-(3.5) results from the computation of the KKT conditions of maximization model (3.1)-(3.3) with respect to $g_{f,i}^t$, $gp_{f,i,m}^t$, $\nu_{f,i,m}^t$, $\eta_{f,i}^t$, where the dual variables $\nu_{f,i,m}^t$, $\eta_{f,i}^t$ are the lagrangian multipliers of constraints (3.2) and (3.3) respectively. Condition (3.4) states that generator f sells electricity $g_{f,i}^t$ when its marginal production costs $\eta_{f,i}^t$ equal electricity prices p_i^t. In fact, by condition (3.5), $\eta_{f,i}^t$ corresponds exactly to the sum of the fuel costs $cost_{f,i,m}$ and the scarcity rent $\nu_{f,i,m}^t$. This equality holds for positive level of electricity $gp_{f,i,m}^t$ produced. Looking at conditions (3.4) and (3.5), the utilization of two different notation for production ($gp_{f,i,m}^t$ and $g_{f,i}^t$) may appear redundant. Hoverer, we want to keep both production variables because this model (and the following ones) can be used for possible extensions to imperfect competition models. In that case, the distinction between electricity produced and sold is necessary since generators may exercise market power manipulating the variable $g_{f,i}^t$. Finally, conditions (3.6) and (3.7) are respectively the reformulation of the generation condition (3.2) and the capacity constraint (3.3).

The constraints included in the power generators' optimization problem refer to hours. This results from the fact that generation and flow needs are exactly balanced per hour since electricity is not storable. Finally, all variables included in this optimization model are assumed to be non-negative. In GAMS, we account for this additional constraint simply declaring them as "positive variables".

3.2.3 Consumers' Surplus Maximization Model

EIIs and N-EIIs desire to maximize their respective annual surplus (3.8) and (3.10) for given electricity and transmission prices. From a graphical point of view, consumers' surplus corresponds to the area under the demand curve at the node and above the market electricity price at that node. The first term in objective functions (3.8) and (3.10) indicates the EIIs and N-EIIs' willingnesses to pay in each period. The remaining part defines the amount that they really pay. In perfect competition, power prices p_i^t are identical between consumer segments and directly include transmission costs as we will explain in Section 3.2.4. Recall that the apexes "*1*" and "*2*" represent respectively EIIs and N-EIIs. Like in Section 3.2.2, we report both the optimization and the complementarity problems.

- **EIIs:**

$$\textbf{Max} \quad \sum_{t=s,w} \left[hour^t \cdot \int_0^{d_i^{t,1}} P_i^{t,1}(\epsilon) \cdot d\epsilon - hour^t \cdot p_i^t \cdot d_i^{t,1} \right] \qquad \forall\, t, i \tag{3.8}$$

$$d_i^{s,1} - d_i^{w,1} = 0 \quad (\alpha_i) \quad \forall\, i \tag{3.9}$$

- **N-EIIs:**

$$\textbf{Max} \qquad hour^t \cdot \int_0^{d_i^{t,2}} P_i^{t,2}(\epsilon) \cdot d\epsilon - hour^t \cdot p_i^t \cdot d_i^{t,2} \qquad \forall\, t, i \tag{3.10}$$

N-EIIs require a quantity $d_i^{t,2}$ of electricity. It differs per node i and period t. In contrast, EIIs' demand $d_i^{t,1}$ is constant over time. In order to model this assumption, we add constraint (3.9) to impose the equality between their hourly summer ("s") and hourly winter ("w") consumption. This condition is matched with the dual variable α_i that affects industrial consumers' electricity prices as indicated in complementarity conditions (3.11) and (3.12) reported below. In these complementarity conditions, we split industrial electricity demand and the related price in sub-variables (respectively $d_i^{s,1}$, $d_i^{w,1}$ and p_i^s, p_i^w) to explicitly account for the summer and winter periods. In the objective function (3.8), we do not make this differentiation since we consider the annual industrial surplus.

Complementarity problem (3.11)-(3.14) corresponds to the KKT conditions of (3.8)-(3.10) computed with respect to $d_i^{t,1}$, $d_i^{t,2}$ and α_i. Note that (3.11), (3.12) and (3.14) are exactly the EIIs and N-EIIs' inverse demand functions and express the reasoning implicitly defined by (3.8) and (3.10). In particular, EIIs and N-EIIs consume electricity ($d_i^{s,1}$, $d_i^{w,1}$ and $d_i^{t,2}$) when prices p_i^t are lower (or identical) than their willingness to pay for the first power unit.

$$0 \leq p_i^s - \alpha_i - a_i^{s,1} + b_i^{s,1} \cdot d_i^{s,1} \perp d_i^{s,1} \geq 0 \quad \forall\, i \tag{3.11}$$

$$0 \leq p_i^w + \alpha_i - a_i^{w,1} + b_i^{w,1} \cdot d_i^{w,1} \perp d_i^{w,1} \geq 0 \quad \forall\, i \tag{3.12}$$

$$0 \leq d_i^{s,1} - d_i^{w,1} \perp \alpha_i \geq 0 \quad \forall\, i \tag{3.13}$$

$$0 \leq p_i^t - a_i^{t,2} + b_i^{t,2} \cdot d_i^{t,2} \perp d_i^{t,2} \geq 0 \quad \forall\, t, i \tag{3.14}$$

3.2.4 Market Balance and Transmission Constraints

As already said, our reference model is based on a nodal pricing system[4]. This can be represented as one where the Transmission System Operator (TSO) sells injection and withdrawal services so as to maximize the value of the transmission capacities of the grid.

As already said, electricity is a special commodity since it can not be stored. Real-time equality of production and consumption is necessary for the well-functioning of the physical grid. This balance is defined by (3.15).

$$\sum_{f,i} g_{f,i}^t - \sum_i d_i^{t,1} - \sum_i d_i^{t,2} = 0 \quad (phub^t) \quad \forall\, t \tag{3.15}$$

The energy balance constraint is paired with the dual variable $phub^t$ representing the market clearing price set at the hub node in each period t analyzed. The hub node is supposed to be a virtual market, where all electricity asks and bids converge. The hub price $phub^t$ is then defined by matching energy demand and supply. This price plus the costs "needed" to transfer electricity from the hub to the node where EIIs and N-EIIs are located give nodal electricity prices p_i^t (see condition (3.16)). Such a regulation of the system implies that the generator receives and the consumer pays nodal prices.

[4] In reality, the pricing mechanism is zonal, but we refer to nodal because the mathematical formulation used has been established for nodal models.

The result is that consumers situated in the hub node only pay the hub price and then do not face network costs. Nodal prices are then written as:

$$p_i^t = phub^t + \sum_l (-\mu_l^{t,+} + \mu_l^{t,-}) \cdot PTDF_{l,i} \quad \forall\, t, i \tag{3.16}$$

The transmission costs $(-\mu_l^{t,+} + \mu_l^{t,-}) \cdot PTDF_{l,i}$ are obtained by multiplying the variables $-\mu_l^{t,+}$ and $\mu_l^{t,-}$ by the Power Transfer Distribution Factor $PTDF$ matrix. Note that $-\mu_l^{t,+}$ and $\mu_l^{t,-}$ are respectively paired with flowgate (line) constraints (3.17) and (3.18). Network constraints are represented in accordance with the DC load flow approximation and the $PTDF$ matrix is used to this aim. Its functioning is explained in Section 2.1.1 of Chapter 2. Transmission constraints account for the double direction that power flows can follow and line capacities are introduced by the parameter $Linecap_l$. As already said, a flow can follow both directions along each network line. Therefore, we introduce two transmission constraints (3.17) and (3.18) to account for the upper and the lower line bounds in each period t. In this case, power flows correspond to $\sum_f g_{f,i}^t - d_i^{t,1} - d_i^{t,2}$, i.e. the total nodal production minus nodal consumption of the two consumer groups.

$$(\sum_i PTDF_{l,i} \cdot (\sum_f g_{f,i}^t - d_i^{t,1} - d_i^{t,2})) \leq Linecap_l \quad (\mu_l^{t,+}) \quad \forall\, t, l \tag{3.17}$$

$$-(\sum_i PTDF_{l,i} \cdot (\sum_f g_{f,i}^t - d_i^{t,1} - d_i^{t,2})) \leq Linecap_l \quad (\mu_l^{t,-}) \quad \forall\, t, l \tag{3.18}$$

Depending on the direction of the flow saturating the line capacity, the inequalities yield the scarcity transmission costs $\mu_l^{t,+}$ and $\mu_l^{t,-}$, which affect electricity prices, as shown in relation (3.16). Last but not the least, the dual $\mu_l^t = \mu_l^{t,+} - \mu_l^{t,-}$ can assume a positive or a negative sign, depending on the direction of the flow that congests the line.

Finally, complementarity conditions of equalities (3.15) and (3.16) and inequalities (3.17) and (3.18) are respectively assembled in the following set of pricing conditions:

$$0 \leq \sum_{f,i} g_{f,i}^t - \sum_i d_i^{t,1} - \sum_i d_i^{t,2} \perp \; phub^t \geq 0 \quad \forall\, t \tag{3.19}$$

$$0 \leq p_i^t - phub^t - \sum_m (-\mu_l^{t,+} + \mu_l^{t,-}) \cdot PTDF_{l,i} \perp p_i^t \geq 0 \quad \forall\, t, i \tag{3.20}$$

$$0 \leq Linecap_l - (\sum_i PTDF_{l,i} \cdot (\sum_f g_{f,i}^t - d_i^{t,1} - d_i^{t,2})) \perp \mu_l^{t,+} \geq 0 \quad \forall\, t, l \tag{3.21}$$

$$0 \leq Linecap_l + (\sum_i PTDF_{l,i} \cdot (\sum_f g_{f,i}^t - d_i^{t,1} - d_i^{t,2})) \perp \mu_l^{t,-} \geq 0 \quad \forall\, t, l \tag{3.22}$$

3.3 Introduction of the Emission Constraint

In order to model the cap on emissions, we add condition (3.23) to the perfect competition model without environmental regulation ("NETS_R") presented in Section 3.2. The allowance price λ (in €/ton) is endogenously defined and results as a shadow price of constraint (3.23).

$$\sum_{t,f,i,m} gp^t_{f,i,m} \cdot em_m \cdot hour^t \leq CAP \quad (\lambda) \tag{3.23}$$

This expression reads as follows. The total emission produced over the year (annual generation times emission factor per technology m must not exceed the annual emission cap CAP. The value of λ is positive when the total amount of emissions equals the cap CAP. This means that the emission policy is binding. This opportunity cost influences electricity prices, generators' wealth and market optimality conditions. Generators, in fact, have to account for the emission opportunity costs in their profit optimization problem. The emission cap corresponds to the sum of NAPs (restricted to the power sector in this case) of the countries involved in our analysis. Recall that the NAPs represent the amount of CO_2 that the installations covered by the EU-ETS are allowed to generate. From a modelling point of view, the introduction of the EU-ETS implies the inclusion of the following term in the profit function (3.1) of generator f presented in Section 3.2.2:

$$+\lambda \cdot (E_f - \sum_{t,i,m} gp^t_{f,i,m} \cdot em_m \cdot hour^t)$$

The term E_f corresponds to amount of allowances that generator f receive for free. Against what it is stated in Directive 2003/87/EC[5] allowances were totally distributed for free (at least in the countries studied) in the period (2005-2007). Since we do not model the economic distortions arising from the different allocation methods, we assume that allowances are given once for all. This makes grandfathering equivalent to auctioning. However, for the sake of generality, we keep the E_f in the formulation of generators' profits. In fact, the parameter E_f can assume a range of values by starting from zero (no grandfathering or auctioning) to the total amount of allowances needed (full grandfathering). The meaning and the structure of the emission constraint here presented remain identical also for the average cost pricing models. Considering the complementarity condition formulation, one has:

$$0 \leq CAP - \sum_{t,f,i,m} g^t_{f,i,m} \cdot em_m \cdot hour^t_i \perp \lambda \geq 0 \tag{3.24}$$

$$0 \leq cost_{f,i,m} + \nu^t_{f,i,m} + em_m \cdot \lambda - \eta^t_{f,i} \perp gp^t_{f,i,m} \geq 0 \quad \forall\ t, f, i, m \tag{3.25}$$

Condition (3.24) corresponds exactly to the emission constraint (3.23). On the other side, (3.25) replaces condition (3.5) in the former generators' optimization problem, when we do not account for a restrictive environmental policy. Note that (3.25) and (3.5) differ only for the term $em_m \cdot \lambda$, which represents the carbon opportunity cost and depends on technologies. Moreover, the parameter E_f does not appear in the complementarity conditions of generators' problem, since it does not affect their strategical behaviour. However, we account for that in the computation of generators' profits and then of the welfare. In Chapters 4, 5 and 6, we show how generators' profits changes under the assumptions of full grandfathering and auctioning. The model allows also for all the intermediate assumptions.

[5]Even though, Directive 2003/87/EC allows for 5% of allowances to be auctioned in the first phase 2005-2007. During that period, they were completely grandfathered free in almost all the countries included the countries studied. In fact, only four (Denmark, Hungary, Lithuania and Ireland) out of 25 Member States used auctions, and in only one case (Denmark), auctions have been employed to the 5% limit.

3.4 Average Cost Pricing Mechanism

As we will show in Chapter 4, our results comply with the thesis that the implementation of the EU-ETS increases electricity prices and induce a corresponding reduction of consumers' demand. This reduction can be interpreted as a mix of different phenomena. The improvement of energy efficiency whether by better processes or a less energy intensive mix of consumption goods is the intended effect. The relocation of activities towards environmentally less rigorous regions of the world is the undesired but plausible result. Our current understanding of the demand sector does not allow one to separate these different components. In this exercise, we attribute the whole reduction of demand to carbon leakage. This would imply a loss of economic activities inside Europe and an increase of emissions outside. Because this phenomenon serves neither the EU nor the environment and in order to explore a possible alternative to that outcomes, we modify the basic model and suppose a different pricing scheme for electricity. Specifically we assume that industrial consumers either pay full average generation cost or directly control part of the generating capacity installed in the network. The question is whether this would reduce the drop of electricity demand (and hence its interpretation in terms of reduction of economic activities) while maintaining the emission objective.

This approach is implemented as follows: the market is segmented into two sub–markets respectively representing the electricity intensive industries (EIIs) and the rest of the market (N-EIIs). As a direct consequence, the generation system is also split between these two market segments. This subdivision is endogenously determined since the final demand of the large industrial consumers is also endogenously defined. We shall see that the principle underlying this allocation is to equalize the marginal value of the capacities allocated to the two segments. Within this market segmentation, we assume that N-EIIs are still priced at the short-run marginal costs. In contrast, electricity intensive industrial consumers pay electricity on the basis of an average cost pricing system corresponding to the full cost of the power plants reserved for them. We consider two particular applications of this view.

We first represent a case where industrial consumers conclude contracts with electricity produces by the means of an European power purchase consortium. Their electricity is priced at the same average cost in any node. The assumption corresponds to a request of industries to achieve a single electricity price on the continental "copper plate" through extended countertrading. Energy intensive industries (and also seemingly the European authorities) indeed consider this uniform price desirable. In this scenario, the final industrial electricity price includes both the average production and the average transmission costs that generally has to be paid to the TSO.

We also model a second case, where we suppose that EIIs buy only electricity locally produced. This leads to a nodal average cost based price system. In this way, industrial consumers are relieved from paying transmission costs, but they are subject to the various constraints that affect generation at that node. In other words, they are not free to choose the technology used to supply them. This makes electricity prices strictly depending on the fuel mix at the node and hence on local constraints on energy technologies. Sections 3.4.2 and 3.4.3 describe respectively the single and the nodal average cost models.

The average cost price formulation makes the mathematical problem more complex because the averaging process presented in the pricing to EIIs destroys the convexity properties of the model and may also make the problem infeasible. This will be in particular the case if the fixed charge included in the price increases this latter too much. In general, absence of convexity properties generates numerical difficulties. In order to attempt to mitigate these numerical difficulties, we solve the average cost based models as a sequence of two different sub-problems. For each average cost price model, we first simulate a market with capacity splitting and demand segmentation where both consumer segments are priced at the short-run marginal costs (the so-called "preliminary problem"). This preliminary problem is convex and always has a solution. This preliminary step amounts to simulating a standard competitive model. Its solution is employed as starting point for solving the problems with average cost pricing system.

We then run the models accounting for the average cost pricing systems. These problems may either not have a solution or have multiple disjoint solutions that can be found by changing the starting point of the algorithm employed. This is perfectly possible in theory because of non-convexity but it also occurs in practice. In our specific case, our single and the nodal average cost pricing models are feasible both with and without the preliminary model. Their solutions change in the two approach considered since we consider different starting points[6].

The maximization problem representing N-EIIs' sector is identical in both the preliminary and the average cost problems; changes concern only industrial consumers' equations. For the sake of simplicity, we do not report the formulation of the preliminary models. The reader should simply note that these preliminary models are quite similar to the average cost problems presented in the following sections: one just replaces the average cost with a marginal cost based price.

Both average cost pricing mechanisms adopt the same representation of perfectly competitive transmission and emission markets as the reference model. Moreover, the main structure and the constraints of the average cost based problems are quite similar to the those of the reference case. Generators desire to maximize their annual profits under the standard production and capacity constraints. On the other side, consumers maximize their global surpluses. We still present the complementarity condition version of the single and the nodal average cost pricing systems. These follow the standard formulation of the market players' maximization problems.

3.4.1 Notation of the Average Cost Pricing Models

Indexes and sets are as in Section 3.2.1. In the average cost pricing models we account for the market segmentation between EIIs and N-EIIs. For this reason, we introduce specific variables in order to identify these two customer sectors. The apexes "*1*" and "*2*" are still adopted to indicate respectively EIIs and N-EIIs. In the reference case, instead, there is no need to make this differentiation because we do not model market segmentation.

Since industrial consumers require a constant amount of electricity, we assume that the variables of their models do not depend on time index t. On the other side, N-EIIs consume more electricity in winter than in summer and, then, we maintain the time discrimination in their variables. Furthermore, we do not repeat the variables regarding the emission and the transmission constraints presented in Section 3.2.1 since they are unchanged. We need to add two variables β^1 and β^1_i that play a technical role and whose interpretation will become clear later. Similar remarks hold for the indexation of parameters.

A. **Variables**

[6] In Section 4.6 of Chapter 4 we present the solutions to the average cost pricing scenarios obtained when we do not run the preliminary model.

Generators

- $g^1_{f,i}$; $g^{t,2}_{f,i}$ — Hourly power sold at node i by generator f respectively to EIIs "*1*" and N-EIIs "*2*" in MW. N-EIIs' variable differs by period t;
- $gp^1_{f,i,m}$; $gp^{t,2}_{f,i,m}$ — Hourly generated electricity in MW by unit m owned by generator f at node i to supply respectively EIIs "*1*" and N-EIIs "*2*". N-EIIs' variable differs by period t;
- $G^1_{f,i,m}$; $G^2_{f,i,m}$ — Capacity of type m that generator f located in i dedicates respectively to EIIs "*1*" and N-EIIs "*2*" in MW;
- $\nu^1_{f,i,m}$; $\nu^{t,2}_{f,i,m}$ — Dual variables representing the marginal value of capacity (scarcity rent) of plant m owned by generator f in location i allocated to EIIs "*1*" and N-EIIs "*2*". N-EIIs' variable differs by period t;
- $\eta^1_{f,i}$; $\eta^{t,2}_{f,i}$ — Dual variable expressing the marginal production costs by generator f and node i concerning respectively EIIs "*1*" and N-EIIs"*2*". N-EIIs' variable differs by period t;
- $\nu_{f,i,m}$ — Dual variable matched with the overall market (EIIs and N-EIIs) capacity constraint (see below for interpretation).

Consumers (EIIs and N-EIIs)

- d^1_i; $d^{t,2}_i$ — Hourly power in MW required respectively by EIIs "*1*" and N-EIIs"*2*" located at node i. N-EIIs' variable differs by period t;
- $P(d^1_i)$; $P(d^{t,2}_i)$ — Inverse demand function representing respectively the EIIs "*1*" and N-EIIs "*2*" willingness to pay. N-EIIs' variable differs by period t.

Electricity Prices

- p^1 — €/MWh single average cost price of electricity paid by industries "*1*". It is composed of two terms: the single production ($pprod^1$) and the single transmission ($ptrans^1$) average costs;
- p^1_i — €/MWh nodal average cost price of electricity paid by industries "*1*";
- $p^{t,2}_i$ — €/MWh nodal price paid by N-EIIs "*2*" in each period t;
- $phub^{t,2}$ — €/MWh price of electricity set at the hub node in each period for N-EIIs "*2*";
- β^1 — Dual variable matched with the industrial market balance constraint in the single average cost pricing model. It can be interpreted as the marginal cost/price at the hub of the electricity generated by the capacities dedicated to industries;

- β_i^1 Dual variable matched with the industrial nodal balance in the nodal average cost pricing model. It can be interpreted as the nodal marginal cost/price of the electricity generated by the capacities dedicated to industries.

B. **Parameters**

In this case, the EIIs' demand parameters do not depend on time t. The corresponding parameters of N-EIIs are as in Section 3.2.1.

Consumers (EIIs and N-EIIs)

- a_i^1 Intercept of demand function of EIIs' demand at node i ;
- b_i^1 Slope of demand function of EIIs' demand at node i;

3.4.2 Single Average Cost Pricing Model (ETS_SAC)

Accounting for the idea that industrial consumers demand a constant level of electricity over the year, we first consider a single average cost price model whereby industrial consumers can purchase power at the same price in any location. We first present the formulation of the single average cost price. Then, we describe the generators and consumers' optimization problems. Finally, we consider the global market constraints represented by the network and the emission restrictions. We refer to this single average cost case as "ETS_SAC".

Single Average Cost Price Formulation

The single average cost price (p^1) paid by large industries is given by the average production cost (variable and fixed charges) of the capacity that they control, plus the average transmission costs for delivering the energy from the injection nodes to the demand nodes. These expressions are obtained as follows. Note that, by definition, we have to account for the annual costs faced by power companies and, then, we multiply all variables by 8760, which is the number of hours in one year.

- The average production cost ($pprod^1$) is the price paid by industries to power companies. It is constant throughout the year and hence does not differ per period:

$$pprod^1 = \frac{(\sum_{f,i,m}(gp^1_{f,i,m} \cdot (cost_{f,i,m} + em_m \cdot \lambda) \cdot 8760))}{\sum_i d_i^1 \cdot 8760} + \\ + \frac{\sum_{f,i,m} FC_{f,i,m} \cdot G^1_{f,i,m}}{\sum_i d_i^1 \cdot 8760} \tag{3.26}$$

where $FC_{f,i,m}$ are the annual fixed charges, depending on generator f, technologies m and locations i of the plant capacities $G^1_{f,i,m}$ dedicated to EIIs. The parameter $FC_{f,i,m}$ is computed as explained in Section 2.1.2 in Chapter 2. Its values are as in Table 2.4 of Section 2.1.2. Note that we assume that they are identical for all generators, even though they depend on f.

The annual fixed costs $FC_{f,i,m}$ are therefore multiplied by the endogenous variable $G^1_{f,i,m}$ representing the capacities reserved for industries. The single (but also the nodal) average cost pricing system is based on an accounting scheme. This price accounts for all the proportions of energy produced by the different plants m owned by generators f in node i. For this reason, both fixed costs $FC_{f,i,m}$ and capacities $G^1_{f,i,m}$ dedicated to EIIs are function of those three indexes. The contribution of fixed charges to the average cost price depends on the technologies that produce electricity for EIIs. Fuel ($cost_{f,i,m}$) and emission ($em_m \cdot \lambda$) costs represent the variable charges.

- The average transmission cost ($ptrans^1$) is obtained as:

$$ptrans^1 = \frac{(\sum_{l,i} PTDF_{l,i} \cdot (\sum_f g^1_{f,i} - d^1_i) \cdot 8760 \cdot \sum_t (\mu_l^{t,+} - \mu_l^{t,-}) \cdot proportion^t)}{\sum_i d^1_i \cdot 8760} \tag{3.27}$$

- The sum of these two terms gives the total average cost price p^1 paid by the industrial consumers:

$$p^1 = pprod^1 + ptrans^1 \tag{3.28}$$

We do not report the complementarity conditions of (3.26), (3.27) and (3.28), since they are simply obtained by matching these equations with the corresponding average cost prices.

Generators' Optimization Model

Generators sell electricity to the two market segments with the aim of maximizing the profit of supplying N-EIIs and minimizing the costs of producing power for EIIs. Their optimization problem is subject to production and capacity constraints. This results in conditions (3.29)-(3.37) described in the following.

Production expenditures, represented by the input fuel costs, the opportunity allowance costs and the congestion charges are included in the objective function (3.29). The amount of electricity $g^{t,2}_{f,i}$ sold and the marginal cost price $p^{t,2}_i$ applied to N-EIIs are directly included in this optimization problem. Because of the average cost pricing system, generators do not maximize their profit from delivering electricity to EIIs. They are only free to minimize the corresponding production and emission costs. That can be done by introducing a shadow price β^1 (see the following) and taking into account the transmission costs.

Due to the complexity of the average cost pricing model and the presence of two prices[7] in the EII's problem, we use a Quasi-Variational Inequalities (QVI) approach to explain the EIIs' pricing mechanism and define the quantity of electricity $g^1_{f,i}$ that they buy from generators. We present it in the following. Note that the

Again, all variables are expressed in hours. In order to have annual values, we multiply the N-EIIs' variables by the parameter $hour^t$ defining the duration in hours of the summer and winter periods. In contrast, industrial variables are multiplied by the number of hours in one year (8760), since they are independent of time.

[7]The average production cost $prod^1$ and β^1 are the two prices included in the EIIs' problem. The first represents the price at which industries buy electricity from generators; the second is the marginal price that industries should pay under perfect competition. This variable β^1 has an important role in our average cost models since it allows generators to split capacity in an efficient way.

$$\textbf{Max} \quad \sum_{t,i} p_i^{t,2} \cdot g_{f,i}^{t,2} \cdot hour^t + \tag{3.29}$$

$$-\sum_{i,m} cost_{f,i,m} \cdot gp_{f,i,m}^1 \cdot 8760 - \sum_{t,i,m} cost_{f,i,m} \cdot gp_{f,i,m}^{t,2} \cdot hour^t +$$

$$+\lambda \cdot (E_f - (\sum_{i,m} gp_{f,i,m}^1 \cdot em_m \cdot 8760 + \sum_{t,i,m} gp_{f,i,m}^{t,2} \cdot em_m \cdot hour^t))$$

subject to:

$$0 \leq g_{f,i}^1 \leq \sum_m gp_{f,i,m}^1 \quad (\eta_{f,i}^1) \quad \forall\, f, i \tag{3.30}$$

$$0 \leq g_{f,i}^{t,2} \leq \sum_m gp_{f,i,m}^{t,2} \quad (\eta_{f,i}^{t,2}) \quad \forall\, t, f, i \tag{3.31}$$

$$0 \leq gp_{f,i,m}^1 \leq G_{f,i,m}^1 \quad (\nu_{f,i,m}^1) \quad \forall\, f, i, m \tag{3.32}$$

$$0 \leq gp_{f,i,m}^{t,2} \leq G_{f,i,m}^2 \quad (\nu_{f,i,m}^{t,2}) \quad \forall\, t, f, i, m \tag{3.33}$$

$$0 \leq G_{f,i,m}^1 + G_{f,i,m}^2 \leq G_{f,i,m} \quad (\nu_{f,i,m}) \quad \forall\, f, i, m \tag{3.34}$$

$$\sum_{f,i} g_{f,i}^1 - \sum_i d_i^1 = 0 \quad (\beta^1) \tag{3.35}$$

$$(\sum_i PTDF_{l,i} \cdot (\sum_{f,i} g_{f,i}^1 + \sum_{f,i} g_{f,i}^{t,2} - d_i^1 - d_i^{t,2})) \leq Linecap_l \quad (\mu_l^{t,+}) \quad \forall\, t, l \tag{3.36}$$

$$-(\sum_i PTDF_{l,i} \cdot (\sum_{f,i} g_{f,i}^1 + \sum_{f,i} g_{f,i}^{t,2} - d_i^1 - d_i^{t,2})) \leq Linecap_l \quad (\mu_l^{t,-}) \quad \forall\, t, l \tag{3.37}$$

As already observed in Section 3.2.2, generators must account for nodal production condition ((3.30) and (3.31)) and technological generation limits ((3.32), (3.33) and (3.34)). Those constraints affect the hourly production of electricity. The meaning of conditions (3.30) and (3.31) is similar to that explained for inequality (3.2) of the reference model, even if their formulation is different. This is due to the assumption of market segmentation, which implies a duplication of all variables. Dual variables $\eta_{f,i}^1$ and $\eta_{f,i}^{t,2}$ are still the marginal electricity generation costs that generators face to supply respectively EIIs and N-EIIs. Conditions (3.36) and (3.37) are the transmission constraints which are matched with the shadow congestion costs $\mu_l^{t,+}$ and $\mu_l^{t,-}$ respectively and (3.35) is the energy balance constraint for the industrial market which is associated with the dual slack β^1. We explain its economical interpretation later. Note that (3.36) and (3.37) are global constraints and refer to both EIIs and the N-EIIs' markets.

We recall that in this particular average cost scenario, generators constitute a consortium in order to supply EIIs. Their final goal is to satisfy industries' electricity demand d_i^1 by applying a single average production cost. Each generator f decides his electricity production level taking into account the behaviour of all the other power producers. It means that the strategy set of generators f is influenced by the production decision of other competitors. This leads to a quasi variational inequality representation of the maximization problem (3.29)-(3.37) defined by a function F and a set K (see Section 2.2 in Chapter 2). In his seminal paper ([26]), Harker introduces quasi-variational inequality

(QVI) problems and shows their relationship with Generalized Nash Games (GNE) and variational inequality (VI) problems (for their definitions refer to Section 2.2).

In our specific case, the optimization problem (3.29)-(3.37) can be transformed into a QVI problem where the gradient map F_f of each generator f is defined by the KKT conditions of problem (3.29)-(3.34) computed with respect to dual and primal variables therein. The point to set map K_f which determines the quantity of electricity $g^1_{f,i}$ produced for EIIs by each generator f is affected by *(1)* the $j \neq f$ production level, *(2)* the EIIs' demand d^1_i and *(3)* the transmission constraints represented by (3.36) and (3.37). It is defined as follows for each generators f:

$$K_f = \{g^1_{f,i} | \sum_{f,i} g^1_{f,i} \geq \sum_i d^1_i \quad and$$

$$\sum_i PTDF_{l,i} \cdot \sum_{f,i} g^1_{f,i} \leq Linecap_l + (\sum_i PTDF_{l,i} \cdot (\sum_{f,i} g^{t,2}_{f,i} - d^1_i - d^{t,2}_i))$$

$$\sum_i -PTDF_{l,i} \cdot \sum_{f,i} g^1_{f,i} \leq Linecap_l + (\sum_i PTDF_{l,i} \cdot (\sum_{f,i} g^{t,2}_{f,i} - d^1_i - d^{t,2}_i))\}$$

Note that the transmission constraints are re-written in order to show the relation between $g^1_{f,i}$ and all the other variables. Moreover, K_f is a polyhedral strategy set. As Harker ([26]) recalls, QVI problem has multiple solutions and its solution set generally includes that of the associated VI problem. Only under particular conditions the solution sets of VI and the QVI problems coincide (see Theorem 6 in [26]). This happens when the dual variables associated with the constraints defining the feasible regions are identical for all players. These constraints have to be concave and continuously differentiable. Our model satisfies all these conditions. This implies that our QVI problem can be assimilated to a VI problem. Moreover, this results has a natural economic interpretation: all generators pay the same transmission charge (equality of the $-\mu^{t,+}_l, \mu^{t,-}_l$) and they globally minimize the costs of supplying EIIs.

From Section 2.2 of Chapter 2, we know that the solution to any variational inequality problem corresponds to that of a complementarity problem when the definition set is a convex cone (and this is our case). In this way, one gets the complementarity conditions as indicated by (3.38)-(3.48). This complementarity problem corresponds exactly the optimization problem (3.29)- (3.37) presented at the beginning of this Section. It defines the case where generators maximize their profit resulting from selling electricity to N-EIIs and, regarding EIIs, they minimize the total production costs, after paying identical transmission costs for both consumer segments. The functional constraints used to define K_f are also part of the generators' complementarity problem, but we explain their details in the Section dedicated to the presentation of the global constraints. Their complementarity formulation are simply obtained by pairing these conditions (3.35), (3.36) and (3.36) with the respective dual variables β^1, $\mu^{t,+}_l$ and $\mu^{t,-}_l$. Note that the slack β^1 depends neither on producer f nor on nodes i because, by model construction, it represents the global (marginal) price on which all industries and the generators' consortium agree.

$$0 \leq \eta^1_{f,i} - \beta^1 - (\sum_{t,l}(-\mu^{t,+}_l + \mu^{t,-}_l) \cdot proportion^t \cdot PTDF_{l,i}) \perp g^1_{f,i} \geq 0 \quad \forall\, f,i \tag{3.38}$$

$$0 \leq \eta^{t,2}_{f,i} - p^{t,2}_i \perp g^{t,2}_{f,i} \geq 0 \quad \forall\, t,f,i \tag{3.39}$$

$$0 \leq cost_{f,i,m} + \lambda \cdot em_m + \nu^1_{f,i,m} - \eta^1_{f,i} \perp gp^1_{f,i,m} \geq 0 \quad \forall\, f,i,m \tag{3.40}$$

$$0 \leq cost_{f,i,m} + \lambda \cdot em_m + \nu^{t,2}_{f,i,m} - \eta^{t,2}_{f,i} \perp gp^{t,2}_{f,i,m} \geq 0 \quad \forall\, t, f, i, m \tag{3.41}$$

$$0 \leq \sum_m gp^1_{f,i,m} - g^1_{f,i} \perp \eta^1_{f,i} \geq 0 \quad \forall\, f, i \tag{3.42}$$

$$0 \leq \sum_m gp^{t,2}_{f,i,m} - g^{t,2}_{f,i} \perp \eta^{t,2}_{f,i} \geq 0 \quad \forall\, t, f, i \tag{3.43}$$

Condition (3.38) ensures that the operation of the part of the generation system allocated to industrial demand is efficient: it minimizes total costs among plants, taking into account transmission charges ($\mu^{t,\pm}_l$) that have to be paid to obtain an efficient dispatch. In this interpretation, β^1 is the marginal cost/price at the hub of the electricity generated by the capacities dedicated to the industries. In a following Section, we show that β^1 corresponds exactly to the average weighted by period duration of the hub price $phub^{t,2}$ set on N-EIIs' electricity market. The fact that β^1 is equal to the weighted average of $phub^{t,2}$ implies that generators do not any incentive to divert capacity from one market segment to the other because they make the same margin at the hub for identical capacities dedicated to EIIs and N-EIIs. This implies efficiency but, at the same time, means that the EIIs' optimization model includes two different electricity prices: $pprod^1$ and β^i. The first is used for commercial transaction; the second is a transfer price used internally (inside the consortium of generators selling to industries) to ensure that generators operate in an efficient way. However, this creates a discrepancy between what, in terms of payments, power companies would receive using this transfer price and effectively receive from EIIs. By construction, generators are paid at the single average production price $pprod^1$, which accounts for the fixed costs of the capacity that they reserved for industries. This amount is different from the marginal capacity costs. This may negatively affect generators.

The interpretation of the other complementarity conditions (3.39)-(3.43) is identical to that of the corresponding conditions in Section 3.2.2.

The split of capacity is endogenously determined by inequalities (3.32) and (3.33). Variables $G^1_{f,i,m}$ and $G^2_{f,i,m}$ indicate the capacities m respectively dedicated to EIIs and N-EIIs by generator f and node i. As already explained, dedicated capacities depends also on all these indexes since average cost pricing is based on an accounting system. Condition (3.34) guarantees that the sum of the MW capacities that each generator f reserves for the two consumers' sectors must not exceed the total power capacity ($G_{f,i,m}$) installed in the network. Constraints (3.32), (3.33) and (3.34) are respectively matched with the variables $\nu^1_{f,i,m}$, $\nu^{t,2}_{f,i,m}$ and $\nu_{f,i,m}$ representing the scarcity rents. Conditions (3.44), (3.45) and (3.46) are simply the transposition of (3.32), (3.33), (3.34) respectively. An interesting question is to understand the mechanism that drives the endogenous allocation of existing capacities of a generator in the two market segments. Complementarity conditions (3.47) and (3.48) in addition to (3.38) show that capacity allocation between EIIs and N-EIIs is conducted following the rules of a perfectly competitive market. As already observed, the variable β^1 represents the hypothetical marginal cost price that industries should pay, at the hub, under a perfectly competitive regime. Moreover, in conditions (3.47) and (3.48) the auxiliary variable $\nu_{f,i,m}$ indirectly states an equality between $\nu^1_{f,i,m}$ and $\nu^{t,2}_{f,i,m}$. This ensures the effectiveness of the capacity split and equalizes the marginal value of the technologies allocated to the two consumer segments. This guarantees an efficient allocation of generation capacities. Finally, the parameter $proportion^t$ in (3.48) determines the relative duration of each period t in the year.

$$0 \leq G^1_{f,i,m} - gp^1_{f,i,m} \perp \nu^1_{f,i,m} \geq 0 \quad \forall\, f, i, m \tag{3.44}$$

$$0 \leq G^2_{f,i,m} - gp^{t,2}_{f,i,m} \perp \nu^{t,2}_{f,i,m} \geq 0 \quad \forall\, t, f, i, m \tag{3.45}$$

$$0 \leq G_{f,i,m} - G^1_{f,i,m} - G^2_{f,i,m} \perp \nu_{f,i,m} \geq 0 \quad \forall\, f, i, m \tag{3.46}$$

$$0 \leq \nu_{f,i,m} - \nu^1_{f,i,m} \perp G^1_{f,i,m} \geq 0 \quad \forall\, f, i, m \tag{3.47}$$

$$0 \leq \nu_{f,i,m} - \sum_t \nu^{t,2}_{f,i,m} \cdot proportion^t \perp G^2_{f,i,m} \geq 0 \quad \forall\, f, i, m \tag{3.48}$$

Consumers' Surplus Maximization Model

The price discrimination appears also in the surplus maximization problems of EIIs (3.49) and N-EIIs (3.50). Differently from the reference scenario (see condition (3.9) in Section 3.2.3), we do not need to set the equality between the hourly amount of electricity required by large industries in each period, since here their demand and price do not depend on time t. The unique constraint to which consumers' problems are subject is the positivity of the electricity consumption.

- **EIIs:**

$$\textbf{Max } 8760 \cdot \int_0^{d^1_i} P^1_i(\epsilon) \cdot d\epsilon - 8760 \cdot p^1 \cdot d^1_i \quad \forall\, i \tag{3.49}$$

The price p^1 accounts for both the average production and transmission costs that industries pay respectively to generators and the TSO.

- **N-EIIs:**

$$\textbf{Max } hour^t \cdot \int_0^{d^{t,2}_i} P^{t,2}_i(\epsilon) \cdot d\epsilon - hour^t \cdot p^{t,2}_i \cdot d^{t,2}_i \quad \forall\, t, i \tag{3.50}$$

Again, complementarity conditions (3.51) and (3.52) represent the inverse demand functions respectively of EIIs and N-EIIs.

$$0 \leq p^1 - a^1_i + b^1_i \cdot d^1_i \perp d^1_i \geq 0 \quad \forall\, i \tag{3.51}$$

$$0 \leq p^{t,2}_i - a^{t,2}_i + b^{t,2}_i \cdot d^{t,2}_i \perp d^{t,2}_i \geq 0 \quad \forall\, t, i \tag{3.52}$$

Market Balance, Transmission and Emission Constraints

In this Section, we describe in details global market constraints. The presentation includes also transmission constraints (3.36) and (3.37) the EIIs' energy balance (3.35) that are part of the QVI problem of generators. We do not enumerate them in order to avoid any misunderstandings. Moreover, we report their corresponding complementarity conditions. Equality (3.53) defines the market energy balances for N-EIIs. It depends on time t.

$$\sum_{f,i} g^{t,2}_{f,i} - \sum_i d^{t,2}_i = 0 \quad (phub^{t,2}) \quad \forall\, t \tag{3.53}$$

$$p^{t,2}_i = phub^{t,2} + (\sum_l (-\mu^{t,+}_l + \mu^{t,-}_l) \cdot PTDF_{l,i}) \quad \forall\, t, i \tag{3.54}$$

$$\sum_{f,i} g^1_{f,i} - \sum_i d^1_i = 0 \quad (\beta^1)$$

Condition (3.53) is matched with the dual variable $phub^{t,2}$ indicating the clearing price of the N-EIIs' market sector at the hub node. The sum of the hub shadow price and the transmission charges $((\sum_l(-\mu_l^{t,+} + \mu_l^{t,-}) \cdot PTDF_{l,i}))$, is used to compute the marginal electricity prices charged at each node i to N-EIIs as stated by (3.54).

As already specified, constraint (3.35) states the balance between production and consumption of the industrial segment. We pair this constraint with a variable β^1 that plays a role similar to the variable $phub^{t,2}$. For this reason, we interpret β^1 as the hypothetical marginal cost that industries should pay under the perfectly competitive regime when the demand is effectively determined by a marginal price like $phub^{t,2}$. Empirical results show that its value (54.11 €/MWh) corresponds exactly to the average of $phub_i^{t,2}$, on the N-EIIs' market weighted by period duration. This similarity of β^1 and $phub_i^{t,2}$ can be also seen by observing relation (3.38), where the sum of β^1 and the transmission charges assume the role of $p_i^{t,2}$ for N-EIIs in (3.39). It is worthwhile to explain that energy intensive industries face two different pricing structures. As already mentioned, one is real (p^1) in the sense that it corresponds to the commercial transactions (what industries pay to the generators and the TSO). The other (β^1) is virtual in the sense of transfer price. It ensures the efficient internal operations of the capacities dedicated to industries by inducing a cost minimizing dispatch of the units.

The meaning of the transmission ((3.36) and (3.37)) and emission (3.55) constraints is identical to that explained in Sections 3.2.4 and 3.3. The assumption of market segmentation slightly changes them.

$$(\sum_i PTDF_{l,i} \cdot (\sum_{f,i} g^1_{f,i} + \sum_{f,i} g^{t,2}_{f,i} - d^1_i - d^{t,2}_i)) \leq Linecap_l \quad (\mu_l^{t,+}) \quad \forall\, t, l$$

$$-(\sum_i PTDF_{l,i} \cdot (\sum_{f,i} g^1_{f,i} + \sum_{f,i} g^{t,2}_{f,i} - d^1_i - d^{t,2}_i)) \leq Linecap_l \quad (\mu_l^{t,-}) \quad \forall\, t, l$$

$$(\sum_{f,i,m} em_m \cdot gp^1_{f,i,m} \cdot 8760 + \sum_{t,f,i,m} em_m \cdot gp^{t,2}_{f,i,m} \cdot hour^t) \leq CAP \quad (\lambda) \tag{3.55}$$

We conclude by reporting the complementarity conditions of these constraints:

$$0 \leq \sum_{f,i} g^{t,2}_{f,i} - \sum_i d^{t,2}_i \perp phub^{t,2} \geq 0 \quad \forall\, t \tag{3.56}$$

$$0 \leq p_i^{t,2} - phub^{t,2} - (\sum_l (-\mu_l^{t,+} + \mu_l^{t,-}) \cdot PTDF_{l,i}) \perp p_i^{t,2} \geq 0 \quad \forall\, t, i \tag{3.57}$$

$$0 \leq \sum_{f,i} g^1_{f,i} - \sum_i d^1_i \perp \beta^1 \geq 0 \tag{3.58}$$

$$0 \leq Linecap_l - (\sum_i PTDF_{l,i} \cdot (\sum_f g^1_{f,i} + \sum_f g^{t,2}_{f,i} - d^1_i - d^{t,2}_i)) \perp \mu_l^{t,+} \geq 0 \quad \forall\, t, l \tag{3.59}$$

$$0 \leq Linecap_l + (\sum_i PTDF_{l,i} \cdot (\sum_f g^1_{f,i} + \sum_f g^{t,2}_{f,i} - d^1_i - d^{t,2}_i)) \perp \mu_l^{t,-} \geq 0 \quad \forall\, t, l \tag{3.60}$$

$$0 \leq CAP - (\sum_{f,i,m} em_m \cdot gp^1_{f,i,m} \cdot 8760 + \sum_{t,f,i,m} em_m \cdot gp^{t,2}_{f,i,m} \cdot hour^t) \perp \lambda \geq 0 \tag{3.61}$$

3.4.3 Nodal Average Cost Pricing Model

We now modify the single average cost pricing approach and we consider the case where industrial consumers buy electricity through special contracts with local generators. The idea of buying locally is driven by the consumers' wisdom that markets are regional and that it is difficult to conclude a cross-border trade contract. In this way, we get a new price formation reflecting nodal average costs. This implies the existence of different local average cost prices (see condition (3.62) in the following) that depend on the technology employed to generate power in each node. Transmission costs are no longer embedded in the nodal average prices, since there is a direct local connection between industries and generating companies. We assume, in fact, that industrial consumers are supplied only with electricity produced by local power plants dedicated to them. In other words, there is no need to import electricity in order to satisfy the internal industrial demand. Nevertheless, industries remain subject to the various local constraints on available technologies, which unavoidably affects their electricity prices.

All the other assumptions (notably market segmentation and capacity splitting) and the corresponding constraints still hold. The N-EIIs' optimization problem does not change with respect to the previous average cost price model. Slight modifications concern only industries' model.

We first present the nodal average price formulation, followed by the power companies and consumers' optimization problems. In the remaining part of this Section, we introduce the market balance equation and all the other global constraints.

Because of the similarities with the single average cost pricing model, we report only the complementarity conditions subject to modifications. Finally, we name this nodal average cost model "ETS_NAC".

Nodal Average Cost Price Formulation

Nodal average cost prices p_i^1 vary over nodes i and account for the fuel ($cost_{f,i,m}$), the emission ($em_m \cdot \lambda$) and the capacity charges ($FC_{f,i,m}$) associated with the plants m that generator f dedicates to industries in node i. Globally the capacity reserved for industrial consumers is $G^1_{f,i,m}$. This leads to the expression:

$$p_i^1 = \frac{(\sum_{f,m}(gp^1_{f,i,m} \cdot (cost_{f,i,m} + em_m \cdot \lambda) \cdot 8760))}{d_i^1 \cdot 8760} + \frac{\sum_{f,m} FC_{f,m,i} \cdot G^1_{f,i,m}}{d_i^1 \cdot 8760} \tag{3.62}$$

Generators' Optimization Model

Like in the previous cases, generators maximize the profit resulting from selling electricity to N-EIIs and minimize the production costs concerning EIIs by accounting for capacity and production constraints. The fuel and the emission charges included in the generators' profit function (3.63) concern both consumer segments.

$$\textbf{Max} \sum_{t,i} p_i^{t,2} \cdot g_{f,i}^{t,2} \cdot hour^t + \tag{3.63}$$

$$-\sum_{i,m} cost_{f,i,m} \cdot gp^1_{f,i,m} \cdot 8760 - \sum_{t,i,m} cost_{f,i,m} \cdot gp^{t,2}_{f,i,m} \cdot hour^t +$$
$$+\lambda \cdot (E_f - (\sum_{i,m} gp^1_{f,i,m} \cdot em_m \cdot 8760 + \sum_{t,i,m} gp^{t,2}_{f,i,m} \cdot em_m \cdot hour^t))$$

subject to:

$$0 \leq g^1_{f,i} \leq \sum_m gp^1_{f,i,m} \quad (\eta^1_{f,i}) \quad \forall\, f, i \tag{3.64}$$

$$0 \leq g^{t,2}_{f,i} \leq \sum_m gp^{t,2}_{f,i,m} \quad (\eta^{t,2}_{f,i}) \quad \forall\, t, f, i \tag{3.65}$$

$$0 \leq gp^1_{f,i,m} \leq G^1_{f,i,m} \quad (\nu^1_{f,i,m}) \quad \forall\, f, i, m \tag{3.66}$$

$$0 \leq gp^{t,2}_{f,i,m} \leq G^2_{f,i,m} \quad (\nu^{t,2}_{f,i,m}) \quad \forall\, t, f, i, m \tag{3.67}$$

$$0 \leq G^1_{f,i,m} + G^2_{f,i,m} \leq G_{f,i,m} \quad (\nu_{f,i,m}) \quad \forall\, f, i, m \tag{3.68}$$

$$\sum_f g^1_{f,i} - d^1_i = 0 \quad (\beta^1_i) \quad \forall\, i \tag{3.69}$$

The objective function (3.63) is identical to the one of the single average cost model (see (3.29)) as well as the nodal production constraints ((3.64) and (3.65)) and generating capacity restrictions ((3.66), (3.67) and (3.68)). By model construction, we change condition (3.69), which represents the nodal energy balance.

Like in the single average cost model, the maximization model (3.63)-(3.69) can be expressed in $QVI(F_f, K_f)$ form where the function F_f corresponds to the gradient map of the problem (3.63)-(3.68) and the set K_f is defined by constraint (3.69). In particular, K_f is as follows:

$$K_f = \left\{ g^1_{f,i} | \sum_f g^1_{f,i} \geq d^1_i \right\}$$

Note that by model construction industries do not pay congestion costs and then K_f does not account for transmission restrictions. The meaning and the complementarity condition of (3.69) are described in the section devoted to the global market constraints.

Consumers' Surplus Maximization Model

The N-EIIs' optimization problem (3.72) is identical to the one of the single average cost case. In the EIIs' model (3.70), instead, one has to replace the single average cost price p^1 by the nodal average cost price p^1_i. Again, we do not need to add the equality of industries' hourly demand since their electricity consumption does not depend on time t.

- **EIIs:**

$$\textbf{Max} \;\; 8760 \cdot \int_0^{d^1_i} P^1_i(\epsilon) \cdot d\epsilon - 8760 \cdot p^1_i \cdot d^1_i \quad \forall\, i \tag{3.70}$$

The corresponding complementarity formulation is:

$$0 \leq p^1_i - a^1_i + b^1_i \cdot d^1_i \perp d^1_i \geq 0 \quad \forall\, i \tag{3.71}$$

- **N-EIIs:**

$$\textbf{Max}\ \ hour^t \cdot \int_0^{d_i^{t,2}} P_i^{t,2}(\epsilon)\cdot d\epsilon - hour^t \cdot p_i^{t,2}\cdot d_i^{t,2} \quad \forall\ t,i \tag{3.72}$$

Market Balance, Transmission and Emission Constraints

The N-EIIs' energy balance states that the quantity of electricity that generators supply should satisfy consumers' demands in each hour and period. Equations (3.73) and (3.74) are identical in form and in meaning to (3.53) and (3.54) presented in the single average cost price model.

$$\sum_{f,i} g_{f,i}^{t,2} - \sum_i d_i^{t,2} = 0 \quad (phub^{t,2}) \quad \forall\ t \tag{3.73}$$

$$p_i^{t,2} = phub^{t,2} + (\sum_l (-\mu_l^{t,+} + \mu_l^{t,-})\cdot PTDF_{l,i}) \quad \forall\ t,i \tag{3.74}$$

$$\sum_f g_{f,i}^1 - d_i^1 = 0 \quad (\beta_i^1) \quad \forall\ i$$

EIIs' energy equilibrium (3.69) differs from condition (3.35) that applied in the single average pricing model. Here, we assume that generation capacities dedicated to the industrial market are local. This implies that, in any location, there is a binding industrial energy balance as shown by equality (3.69). The former dual variable β^1 is now replaced by the dual variable β_i^1 that matches these conditions and depend on i. The corresponding complementarity conditions are:

$$0 \le \sum_f g_{f,i}^1 - d_i^1 \perp \beta_i^1 \ge 0 \quad \forall\ i \tag{3.75}$$

As in the single average cost pricing model, β_i^1 is the virtual price (equal to the local marginal cost) that industries would have to pay in a perfectly competitive market if demand were the one generated by $p_i^{t,2}$, the N-EIIs' prices. In other words, β_i^1 is an internal transfer price which effectively ensures the right allocation of the generation resources between N-EIIs and EIIs. Our empirical tests show that β_i^1 and the weighted (by period duration) average values of $p_i^{t,2}$ are identical (compare values in Table 3.1).

	$p_i^{t,2}$	β_i^1
Germany	50.63	50.63
France	54.01	54.01
Merchtem	52.43	52.43
Gramme	52.59	52.59
Krimpen	51.99	51.99
Maastricth	51.94	51.94
Zwolle	51.63	51.63

Table 3.1: Comparison between $p_i^{t,2}$ (weighted average) and β_i^1 in €/MWh

This equality between the virtual transfer price and the one paid by the N-EIIs confirms the efficiency of the allocation of capacity between the two sectors. At each node, the two market segments pay the same price. Note that the price β_i^1 appears in the complementarity condition (3.76) which states the equality between marginal electricity prices and costs for positive generation level $g_{f,i}^1$. The interpretation of this condition is analogous to that of (3.38) in the single average cost model. Here, we do not account for transmission constraints since industries do not pay them.

$$0 \leq \eta_{f,i}^1 - \beta_i^1 \perp g_{f,i}^1 \geq 0 \quad \forall\, f, i \tag{3.76}$$

Inequalities (3.77), (3.78) and (3.79) describe respectively the two transmission and the emission constraints. By model assumption, transmission constraints include only the power injections of N-EIIs.

$$(\sum_i PTDF_{l,i} \cdot (\sum_f g_{f,i}^{t,2} - d_i^{t,2})) \leq Linecap_l \quad (\mu_l^{t,+}) \quad \forall\, t, l \tag{3.77}$$

$$-(\sum_i PTDF_{l,i} \cdot (\sum_f g_{f,i}^{t,2} - d_i^{t,2})) \leq Linecap_l \quad (\mu_l^{t,-}) \quad \forall\, t, l \tag{3.78}$$

$$(\sum_{f,i,m} em_m \cdot gp_{f,i,m}^1 \cdot 8760 + \sum_{t,f,i,m} em_m \cdot gp_{f,i,m}^{t,2} \cdot hour^t) \leq CAP \quad (\lambda) \tag{3.79}$$

The modified complementarity conditions are:

$$0 \leq Linecap_l - (\sum_i PTDF_{l,i} \cdot (\sum_f g_{f,i}^{t,2} - d_i^{t,2})) \perp \mu_l^{t,+} \geq 0 \quad \forall\, t, l \tag{3.80}$$

$$0 \leq Linecap_l + (\sum_i PTDF_{l,i} \cdot (\sum_f g_{f,i}^{t,2} - d_i^{t,2})) \perp \mu_l^{t,-} \geq 0 \quad \forall\, t, l \tag{3.81}$$

3.5 Conclusions

It is now recognized that the inception of the ETS in Europe has introduced direct and indirect charges that negatively affect energy and energy intensive sectors. The cost of allowances that industrial consumers buy to cover their emissions represents the direct burden provoked by the EU-ETS. The indirect ETS effect is generated by the increased electricity price. This results from the pass through of carbon cost in electricity price. These additional costs may endanger industries' competitiveness on international markets and induce them to relocate their facilities outside of Europe. Energy intensive industries complain about this situation and propose the implementation of long-term contracts, whereby purchasing electricity at the average production cost, as possible mitigation of the raised power price.

In this Chapter we present the models used in the first stage of our analysis. Our intent consists in studying the indirect impact of the ETS on energy intensive consumers and evaluating the impact of the application of the proposed long-term contracts. We do this by modelling the behaviour of electricity consumers through a demand curve. We first present a reference case modelling a perfectly competitive market where all consumers (N-EIIs and EIIs) pay electricity at the marginal cost price. This reference case was implemented in order to analyze EIIs' electricity demand and price evolution after the inception of the ETS.

We then model the long-term contracts. The application of the average cost pricing system allows generating companies to split the already existing capacities and discriminate pricing approach between consumer groups. Energy intensive industries have the opportunity to pay either a single or a nodal average cost price for electricity, depending on the contract chosen.

In Chapter 4, we will explain in detail the results obtained with simulations applied to the sample of the Central Western European market as depicted in Figure 2.1 of Chapter 2.

Chapter 4

Evaluation of the Application of Average Cost Based Contracts under Fixed Capacity Assumptions

4.1 Introduction

The models presented in Chapter 3 correspond to the first stage of our analysis, where we want to study the indirect ETS impact (through the sole electricity price) on energy intensive industries by assuming that power capacity is fixed in the market. Again, we proceed step by step, by starting from a basic model describing a perfectly competitive market as presented in Section 3.2 of Chapter 3. We first simulate the unconstrained carbon market ("NETS_R") and, then we introduce the emission balance equation ("ETS_R"), in order to quantify the impact of the CO_2 trading system on electricity prices and demand. We compare the cases with and without emission constraint in order to verify if our models behave plausibly compared to market segmentation. This reasoning holds for both EIIs and N-EIIs and results are presented in Section 4.2. Recall that the case accounting for both emission and transmission regulations is meant to represent our reference scenario. Adding the emission balance equation, the model gives the allowance price as output as well as its impact on the price of electricity. This gives us a first assessment on the EU-ETS on EIIs. Recall that we interpret this impact in terms of relocation of industrial activities.

We then implement the single and the nodal average cost pricing models in order to understand the extent to which these special contracts can help energy intensive industries to mitigate the impact of the EU-ETS. We discuss our results comparing industrial electricity demand and prices under both average cost scenarios. In parallel, we also analyze the effects of the application of this pricing policy on N-EIIs to detect the possible transfer effect between the two consumer groups. Section 4.3 is devoted to this study.

In Section 4.4, we conduct the welfare analysis under two different industrial demand elasticity assumptions. We first consider the case when energy intensive industries have an elastic behaviour and their elasticity is -1. We then assume that industries has less flexibility to price changes since we reduce their demand elasticity to -0.8. This modification is introduced in order to check the robustness of our results. Section 4.5 is dedicated to the sensitivity analysis on emission constraint. One innovative aspect of our models is that allowance price is endogenously determined: it corresponds to the dual variable matched with the emission constraint. Without changing the main structure of our models, in this sensitivity analysis, we assume that allowance price is exogenously defined and we first set it at 20 €/ton, since this is the reference allowance price used in several studies (for instance, McKinsey and Ecofys [33], Neuhoff et al. [37] and Reinaud [44]). Secondly, we consider the scenario of 70 €/ton which seems to be a hidden target of European Commission under the new emission commitment and renewable package proposed for 2013-2020 (compare Energy Argus ([1])). Our aim is to study the emission trend and changes of consumers' electricity prices and consumption under this new carbon market assumption. Last, we close the Chapter with some concluding remarks.

4.2 Results of the Perfectly Competitive Model

As already explained, we compare the results of the "NETS_R" and "ETS_R" models in order to measure the EU-ETS effects on power demand and prices. We present these results in separate Sections. Industries and N-EIIs' electricity consumption values are reported in Sections 4.2.1 and 4.2.3 respectively. Section 4.2.2 presents power prices. Emission trends are given in Section 4.2.4.

Generally, the ETS adds a carbon component to the electricity prices and, at the same time, boosts power companies to modify their fuel mix towards less-pollutant technologies. This affects consumers' electricity prices and consequently their consumption. In accordance with our input data, we find two different inter-temporal effects on prices as described in Section 4.2.2.

4.2.1 EIIs' Electricity Consumption

The inception of the EU-ETS causes a general decrease of the electricity consumption of energy intensive industries. These results are certainly in line with the claim of the large industrial consumers. With respect to the NETS_R case, they reduce their electricity consumption by 11% both in summer and in winter.

	NETS_R	**ETS_R**	**Variations**
Germany	32,214	25,095	-22%
France	25,015	24,910	-0.4%
Merchtem	3,573	3,538	-1%
Gramme	2,029	1,963	-3%
Krimpen	2,722	2,603	-4%
Maastricht	942	889	-6%
Zwolle	1,800	1,615	-10%
Total	**68,294**	**60,613**	**-11%**

Table 4.1: EIIs' Electricity Demand in the NETS_R and in the ETS_R Scenarios in MWh

Cuts are identical in each period since EIIs have a constant electricity demand over time. This is followed by a drop of almost 22% in their annual surplus (compare results in Table 4.11). This fall in industries' power demand is significant, but is really driven by our assumptions. The reader should indeed keep in mind that we model industries' long run behaviour and hence assume a demand elasticity of -1. All results are influenced by this model assumption, which is selected to fit the threat exposed by industries: the relocation of their production capacities outside of Europe in the long-term. Table 4.1 shows EIIs' electricity demand before (NETS_R) and after (ETS_R) the introduction of the emission constraint.

These figures highlight that industries' complaints are plausible if the retained long-term price elasticity is reasonable. The threat of these companies to leave Europe and to move their production activities in extra-Community countries should be considered seriously in the sense that it should be assessed carefully and quickly. Note that this result represents a long-term view of the phenomenon: environmental regulation is only one of the determinants of EIIs' strategies. Fuel cost remains the factor that principally affects electricity prices (Stern Review [50]), even if the EU-ETS contribution is becoming more and more relevant.

4.2.2 EIIs and N-EIIs' Electricity Prices

The inception of CO_2 policies also introduces some contrasts in the inter-temporal electricity prices. These are reported in Table 4.2 and are identical for EIIs and N-EIIs. Transmission costs influence summer power prices. In fact, some of the grid connections are congested. In particular, lines are satured between France and Germany and between France and Belgium. The interconnection capacity between the Belgian node Merchtem and the Dutch node Krimpen is congested and the same happens between Gramme and Maastricht. The direction of the flows reveals that France exports both to Germany and Belgium, which, in turn, supplies the Netherlands. Since a great part of the nuclear electricity generated in France is exported, the congestion of the lines, combined with the marginal cost pricing implicit in this model, reduces the French power price to a level close to its marginal operating cost (5.07 €/MWh). This happens even though the price of the neighboring countries is higher. The congestion cost makes the difference.

	Summer		**Winter**	
	NETS_R	**ETS_R**	**NETS_R**	**ETS_R**
Germany	21.62	44.94	51.48	47.36
France	4.50	5.07	47.48	47.36
Merchtem	36.35	46.91	57.26	47.36
Gramme	19.09	27.79	53.22	47.36
Krimpen	36.35	46.91	54.92	47.36
Maastricht	36.35	46.91	54.03	47.36
Zwolle	32.15	46.07	53.66	47.36

Table 4.2: EIIs and N-EIIs' Electricity Prices in the NETS_R and ETS_R Scenarios in €/MWh

In winter, instead, all consumers pay the price set at the hub node because the transmission grid is no longer congested. We recall that we are working with a very rough aggregation of the demand and hence with a lower than observed peak demand. Moreover, this is only true in the carbon constrained version of the model. In fact, without carbon restriction, a line connecting France with Belgium is congested in winter period and, then, the standard economy of nodal transmission system makes electricity prices different in all nodes. Under the EU-ETS, consumers globally reduce their electricity demand and the amount of power exported in winter decreases, avoiding the congestion of the grid. It is then important to recognize the real nature of the phenomenon: the EU-ETS decreases congestion because it reduces industrial demand.

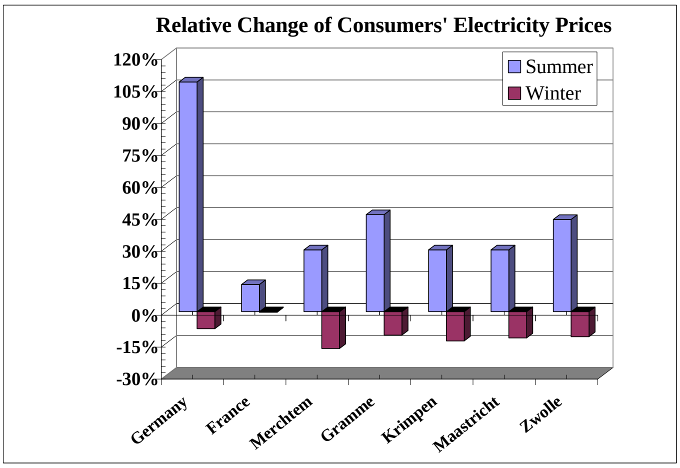


Figure 4.1: Relative Changes of Consumers' Electricity Prices in Summer and in Winter

Figure 4.1 shows the relative changes of consumers' prices under ETS_R with respect to NETS_R case. These refer to both periods. Note that with the implementation of the EU-ETS, electricity prices increase in summer. The change of merit order of the plants can explain these seemingly strange results. We recall that, in perfect competition and when there are no transmission constraints, the most expensive plant sets electricity price at the hub node. In the NETS_R scenario, the price at the hub is 21.62 €/MWh which corresponds exactly to the fuel cost of a coal plant (see Table 2.3 in Chapter 2). With the implementation of the EU-ETS, generators are encouraged to exploit low emitting technologies, like CCGT, and reduce the utilization of more polluting ones (namely coal). In fact, under the EU-ETS, the utilization of CCGT increases by 10% (from 3,616 MW (NETS_R) to 3,992 MW (ETS_R)), while there is a huge cut of 53% of the hourly coal electricity production (from 18,646 MW (NETS_R) to 8,758 MW (ETS_R)). This is mainly due to the demand drop. Tables 4.24 and 4.26 in Appendix 4.8 report the summer electricity generation values by node and technology respectively in the NETS_R and ETS_R scenarios. Besides this technology switch, coal plants define again the electricity price at the hub represented by the German node. In the ETS-R, price in Germany amounts to 44.94 euro/MWh which corresponds exactly to coal fuel cost (21.62 €/MWh) increased by the respective carbon opportunity cost (23.32 €/MWh[1]). The pass through of the allowance price explains why, in summer, power is more expensive in the ETS_R scenario than in the NETS_R case. Hydro, renewable and nuclear capacities are saturated in both periods. In summer the contribution of clean technologies in the ETS_R raises by 5% with respect to the NETS_R case. This followed by an increase of 1% of the utilization of CCGT. As already observed, the proportion of coal electricity production falls after the inception of the EU-ETS by 6%.

In winter, we observe a reverse behaviour: under the emission trading policy, energy prices become lower (see Figure 4.1). The combination of the change of plant merit order and the industrial electricity demand cuts explains this outcome. The EU-ETS obliges generators to modify their fuel mix and

[1]The carbon opportunity cost of a coal plant is computed multiplying the allowance price of the ETS_R scenario (24.44 €/ton) by the emission factor of a coal plant (0.9542 ton/MWh according to our input data).

to switch to lower emitting plants in order to achieve their emission target. In particular, in the NETS_R scenario, power companies use both old single cycle natural gas and oil-fired power plants to satisfy consumers' demand in winter. As we have seen before, the implementation of the carbon market entails a reduction of the annual industrial demand and, consequently, of the electricity that the market globally requires in winter. In this way, the peak load plants (low-efficiency natural gas plants and oil-based stations) that previously were run to cover the winter demand are no longer needed to supply electricity and CCGT becomes marginal CCGT power units therefore determine the winter electricity price (47.36 €/MWh), replacing the natural gas and oil-based installations used in the NETS_R case[2].

This makes power cheaper than before. The EU-ETS has thus two effects: first, it adds a carbon component to electricity prices; second, it removes expensive and inefficient units and modifies the plant merit order. These two impacts of different nature interact with the yearly constant (endogenous) demand level in the industrial sectors. The requirement that industrial demand remains constant throughout the year explains how winter demand and winter prices can simultaneously decrease. The overall price (summer and winter) increases reducing the hourly demand, even thought the sole summer prices increase. This is confirmed by the behaviour of N-EIIs in the winter period: in presence of emission limitations, they increase by 1% their electricity consumptions, since prices are a little bit lower in each node (see Table 4.3). In summer, instead, they lessen their energy utilization (almost -3%) as a consequence of the raised power prices (see Figure 4.1 for price relative changes).

	NETS_R		**ETS_R**		**Variations**	
	Summer	**Winter**	**Summer**	**Winter**	**Summer**	**Winter**
Germany	19,852	47,434	18,746	47,936	-6%	1%
France	22,127	44,524	22,097	44,538	-0.13%	0.03%
Merchtem	1,322	4,382	1,287	4,496	-3%	3%
Gramme	589	1,895	577	1,924	-2%	2%
Krimpen	2,977	7,190	2,899	7,332	-3%	2%
Maastricht	709	1,747	691	1,777	-3%	2%
Zwolle	1,192	2,929	1,151	2,977	-3%	2%
Total	**48,768**	**110,102**	**47,449**	**110,979**	**-3%**	**1%**

Table 4.3: N-EIIs' Summer and Winter Electricity Demand in the NETS_R and ETS_R Scenarios in MWh

Generally, we can say that, thanks to its nuclear policy, France does not suffer from the introduction of a mandatory cap on emissions. Nuclear is a base-load technology and completely meets the ETS proposals with its zero pollution. On the other hand, Germany, with its high consumption of coal and lignite, is more affected as illustrated by the strong German movement to invest in clean technologies, namely (subsidized) renewable capacity. According to our input data, the ETS generally induces generators to limit their utilization of coal-based technologies during the summer period. This especially holds in Germany, where generators prefer to import nuclear electricity from France,

[2]In accordance with our input data, old natural gas and oil-based plants are the last technologies in merit order. Without carbon price, the cost of gas, oil and CCGT are respectively of 55.08 €/MWh, 57.26 €/MWh and 36.57 €/MWh. In this ETS_R case, the emission opportunity cost associated with a CCGT plant is 10.56 €/MWh. This is obtained by the product of the CCGT emission factor (0.432 ton/MWh) and the allowance price (24.44 €/ton). Adding 10.56 €/MWh to 36.57 €/MWh, one gets 47.13 €/MWh that is the total cost of a CCGT unit under the ETS. It is indeed less expensive than old gas and oil-fired stations and moreover it is almost the price given by the model.

instead of using their highly polluting coal and lignite power units.

4.2.3 NEIIs' Electricity Consumption

The effects of the ETS on electricity price also explains the N-EIIs' consumption trend in each period. As already explained, N-EIIs globally increase their winter electricity consumptions by 1%, since power becomes less expensive than in the emission unconstrained case NETS_R. In summer, instead, they lessen their energy utilization (almost -3%) as a consequence of the raised power prices (see Table 4.3).

4.2.4 Emission Analysis

Under the EU-ETS restrictions, the allowance price found is 24.44 €/ton. This positive value signals a tight emission cap. This is not in line with the low allowance price that prevailed in the second part of the first compliance period after global NAPs were commonly judged excessive, but can be explained by our imposing the cap on the sole power sector[3]. Reinaud ([43]) and Smeers ([49]) explain that CCGT and coal plants become competitive when CO_2 price reaches a certain "tipping point". In particular, Smeers in ([49]) argues that this shift between CCGT and coal happens for CO_2 price of around 23.65 €/ton. Reinaud in ([43]) indicates a CO_2 cost of 19 €/ton. Our results are aligned with these studies: only with a high allowance price (like 24.44 €/ton), one forces generators to replace coal technology with less emitting CCGT stations[4]. This is exactly what we have observed. Our cap imposes a reduction of emission compared to the reference NETS_R model and the substitution of coal and gas technologies is the only way to achieve that reduction in our model. The reality of the EU-ETS is that, in the first phase (2005-2007), the power sector was short of allowances while the other involved sectors were long. Assuming perfect trading, the global constraint was globally lower (they may even have no constraints according to some authors) which explains the low price observed in the second half of the first compliance period. We shall recall that it was argued for some time that the sole power sector was trading which may explain the high price (quite compatible with our value) observed in the first eighteen months of the (2005-2007) period[5].

With the application of the environmental policy, carbon emissions globally reduce by 14% from a level of about 464 Mio ton p.a. to 397 annual Mio ton. This is exactly the CO_2 emission ceiling imposed on the power sector in our model. Parallel to the global reduction in electricity consumption, one observes decreased emissions in almost all the nodes of the model. There are two exceptions through: they occur in the Dutch locations Maastricht and Zwolle. In the first of these two nodes, the

[3]Recall that we take this assumption in order to modify our analysis. We are perfectly aware of the fact that power sector can trade allowances with all the other EU-ETS participants. In fact, in Chapter 6, we modify this assumption by introducing energy intensive industries in the emission market.

[4]Smeers and Reinaud indicate different CO_2 switching price. This because their studies are based on different input data. Reinaud assumes that coal and gas fuel prices are respectively 1.5 €/GJ and 3.5 €/GJ; while those of Smeers' study are higher: 2.3 €/GJ (coal) and 3.5 €/GJ (gas). Efficiency rates are identical (0.37 (coal) and 0.49 (gas)) and also gas emission factor (0.412 ton/MWh). Smeers supposes that coal emits more than Reinaud does (0.99 ton/MWh vs 0.918 ton/MWh). In order to check the consistency of these two studies, we compute the CO_2 switching price using Smeers' formula and Reinaud's input data. The result obtained is 19.24 €/ton that is aligned with Renaiud's value. Our input data are more similar to those adopted by Smeers. In particular, we assume that coal costs 2.22 €/GJ with an emission rate of 0.9542 and efficiency rate of 0.37; while gas price is 4.15 €/GJ with an emission factor of 0.432 and efficiency rate of 0.49.

[5]As reported by D. Ellerman in his article available at $http://www.eurekalert.org/pub\_releases/2007-05/oup-rop052407.php$, the value of traded volume to May 2007 is estimated at €14.7 billion.

global emission level increases by 17% with respect to the NETS_R case. Generators, in fact, raise the operation of their CCGT plants in order to reduce their electricity imports, as a consequence of the congestion of the line between Maastricht and the Belgian node Gramme. In Zwolle, instead, the emissions remain constant, since both the capacity and the fuel mix used to produce energy do not change with respect to the unconstrained carbon case.

These results can be generally explained looking at the modifications of the technology mix adopted in the electricity production process.

	NETS_R	**ETS_R**	**Variations**
Germany	323,446,956	273,308,621	-16%
France	58,126,477	43,565,549	-25%
Merchtem	20,878,028	20,103,079	-4%
Gramme	5,868,493	5,275,043	-10%
Krimpen	37,189,229	35,893,515	-3%
Maastricht	6,541,471	7,639,524	17%
Zwolle	11,596,893	11,596,893	0%
Total	**463,647,546**	**397,382,225**	**-14%**

Table 4.4: Nodal Emission Levels in the NETS_R and in ETS_R Scenarios in Ton p.a.

Under the NETS_R case, generators run base-load power plants (hydro, nuclear and lignite installations) at their full capacity in each node both in summer and in winter. Coal and CCGT plants are partially employed in both periods and, moreover, in winter, natural gas and oil-based technologies are also generating (see Tables 4.24 and 4.25 in Appendix 4.8).

As already said, generators modify their fuel combinations in order to comply with the emission targets. The main effect is represented by the shift from highly pollutant coal technologies to more environmental-friendly CCGT plants[6] (compare Tables 4.24 and 4.25 with 4.26 and 4.27 in Appendix 4.8).

In the EU-ETS context and in accordance with our 2005 data, the utilization of CCGT power plants is supported by their high efficiency rates and comparatively low emission factors. Their construction costs are smaller than those of coal and especially nuclear units. All these positive features, joint with low gas prices, encouraged power companies to invest in CCGT during the 90's. The actual gas price scenario is changed (but coal price also increased), but CCGT plants are still in construction.

As already mentioned industries' surplus decrease by 22% under the ETS_R scenario. In contrast, the profit of power companies globally increases by 16% with respect to the unconstrained carbon case (in the case where allowances are completely grandfathered). These gains accrue from the pass through of CO_2 cost in electricity price and in line with the so-called windfall profit theory. All these comply with industrial position: there might be a problem of competitiveness and demand destruction. This effect is not really surprising and results from basic economic phenomena. Because carbon leakage implies both increase of world emissions and a loss of economic activity in EU, this justifies exploring the remedies proposed by EIIs.

[6]According to our input data, the coal emission factor is more than twice of the CCGT. Compare Table 2.6.

4.3 Results of the Average Cost Pricing Policies

It is now well understood that the EU-ETS may cause additional burdens on energy intensive industries. The problem is to find the right way to remedy this phenomenon. EIIs have proposed to conclude long-term contracts with generators in order to reduce their exposure to high marginal fuel costs. Our intent is to implement special contracts, based on the average cost price, in order to explore whether long-term average cost based contracts may mitigate the impact of the EU-ETS on energy intensive industries. This Section shows EIIs' reaction to the application of this alternative pricing system.

The analysis is again conducted with simulations applied to the Central Western European market. Recall that the application of average cost based contracts has two implications: the market is segmented into two sub–markets respectively representing the electricity intensive industries and N-EIIs. As a direct consequence, the generation system is also split between these two market segments. This subdivision is endogenously determined since the industrial final demand is also endogenously determined. It may however fail to be incentive compatible in the sense that generators may have preferred to avoid these special contracts. The model therefore reflects a situation where generators are compelled to conclude special contracts with the EIIs. It means that EIIs may exercise monopsony power, while generators do not have market power. As already explained in Section 3.4.2 of Chapter 3, the principle underlying this allocation is to equalize the marginal value of the capacities allocated to the two segments. This also implicitly amounts to maximizing the total capacity value. Within this market segmentation, we assume that N-EIIs are still priced at the short-run marginal costs. In contrast, energy intensive industries pay electricity at the average costs corresponding to the full cost of the power plants reserved for them. We consider two particular applications of this view: the single (ETS_SAC) and the nodal (ETS_NAC) average cost price systems. The respective models are described in Section 3.4 of Chapter 3.

4.3.1 Impacts of the EU-ETS and Long-Term Contracts on Energy Intensive Industries

Our analysis shows that single and nodal average cost based contracts have different impacts. These depend on their location and the technological mix used to produce electricity in each node. Tables 4.5 and 4.7 report EIIs' electricity prices respectively in the ETS_SAC and ETS_NAC scenarios.

The single average cost price amounts to 38.10 €/MWh (see Table 4.5). Fixed costs contribute for the largest part, followed by the fuel and the emission charges. Industries tend to congest the network by importing from France. For this reason they pay transmission costs to the TSO. In this case, the charge amounts to 2.74 €/MWh. Note that also emissions and transmissions are averaged in the system. This completely fulfills the demand of the EIIs.

Table 4.6 reports, in absolute values, the hourly electricity demand of industries under different pricing scenarios. The ETS_SAC scenario performs better than the ETS_R case and it is able to recover the 36% of the EIIs' power demand loss caused by the inception of the EU-ETS. This is the desired effect since it helps to counters carbon leakage (interpreted here as a decrease of demand of electricity). The application of the single average cost pricing system results in a global increase of 5% of the industrial electricity consumption with respect to the reference case. This mitigates the impacts of the EU-ETS on competitiveness while maintaining its emission target. However, not all industrial consumers benefit from the application of this innovative pricing scheme. In Germany, in the

Cost Components	
Fuel	10.64
Transmission	2.74
Emission	7.32
Capacity	17.39
Average cost price	**38.10**

Table 4.5: Single Average Cost Components in the ETS_SAC Scenario in €/MWh

Netherlands and in the Belgian location Merchtem industries pay electricity at lower prices. Relative changes are between -19% (in Merchtem, Krimpen and Maastricht) and -17% (in Germany). Instead, in France and in the Belgian node Gramme the single average cost pricing system leads respectively to an increase of 69% and 6% of the industrial electricity prices. The direct consequence is that industrial consumers in those locations require less electricity. The decreases of electricity consumption of 22% and 1% respectively in France and in Gramme are globally compensated by the increases of industrial electricity demand in the other nodes.

	NETS_R	**ETS_R**	**ETS_SAC**	**ETS_NAC**
Germany	32,214	25,095	31,065	26,913
France	25,015	24,910	19,408	29,002
Merchtem	3,573	3,538	4,511	2,176
Gramme	2,029	1,963	1,939	2,601
Krimpen	2,722	2,603	3,319	2,119
Maastricht	942	889	1,133	620
Zwolle	1,800	1,615	2,033	1,113
Total	**68,294**	**60,613**	**63,408**	**64,543**

Table 4.6: EIIs' Electricity Demand under Different Fixed Capacity Scenarios in MWh

Like the ETS_SAC also the application of the nodal average cost based policy has a global positive effect on industries which increase their electricity consumption with respect to both the ETS_R (+6%) and the ETS_SAC (+2%) models. The ETS_NAC scenario allows EIIs to recover the 51% of their demand cut deriving from the EU-ETS. This is another signal that confirms that ETS_NAC does generally better than ETS_SAC.
However, looking at the hourly demand values reported in Table 4.6, one can easily notice that energy intensive industries are quite diversely affected depending on the node where they are located. In France and in the Belgian node Gramme, the nodal average cost pricing system represents the best policy to heal industrial difficulties. This is mainly a result of the technological structure in these locations. In a country, like France, where nuclear is the main power source, nodal average cost pricing contracts perfectly suit industrial consumers' needs, since they have wide access to this cheap and clean technology without sharing it with foreign consumers[7].

In contrast, the situation of industries placed in nodes where electricity is mostly produced by CCGT or by coal based technologies is more critical. This is what happens in the Netherlands and in the Belgian node Merchtem, where industries are really damaged by this contractual policy[8].

[7]It is exactly the opposite of what happens in the single average cost pricing scenario.

[8]The cuts of their electricity consumptions are as follows: 39% (ETS_R) and 52% (ETS_SAC) in Merchtem, 19%

In Germany, instead, the industrial electricity consumption decreases by 13% with respect to the ETS_SAC case, but it is higher in comparison with the reference level (+7%).

	Fuel	**Emission**	**Capacity**	**Average cost price**
Germany	11.59	17.59	14.52	**43.70**
France	4.50	0.00	12.89	**17.39**
Merchtem	25.76	22.77	11.25	**59.79**
Gramme	9.03	1.75	13.01	**23.79**
Krimpen	25.58	15.56	12.11	**53.25**
Maastricht	36.35	12.19	8.53	**57.06**
Zwolle	36.35	12.19	8.53	**57.06**

Table 4.7: Nodal Average Cost Components in the ETS_NAC Scenario in €/MWh

The contribution of the components of the nodal average prices (fuel, emission and capacity costs) shown in Table 4.7 may explain the variations of the EIIs' electricity consumptions. Nodal average cost prices depend on the local technology mix adopted to supply EIIs. For instance, in France, the industrial electricity price is 17.39 €/MWh, of which 4.50 €/MWh are the average fuel costs and 12.89 €/MWh are the fixed charges. Generators exploit only nuclear plants[9] to cover French industrial demand. Nuclear is an environment-friendly technology and then French average cost based price does not include emission burdens. Fuel and capacity charges correspond exactly to the costs of nuclear plants, as indicated in Tables 2.3 and 2.4 in Chapter 2.

In Gramme, industries are mainly supplied by hydro, renewable and nuclear (see Tables 4.31 and 4.35 in Appendix 4.8). Moreover, 31% of the available CCGT plants are employed, but these proportions correspond to a few MW of capacity (respectively 373 MW). Hydro and renewable reduce the fuel average cost; while emissions caused by CCGT stations add to this cost. Moreover, 170 MW (corresponding to the proportion of 100% in Table 4.35) of old gas power stations are dedicated to EIIs in Gramme, but they are not run to cover their electricity demand (compare Tables 4.31 and 4.35 in Appendix 4.8). Contrarily, industrial consumers in Merchtem, the other Belgian node, face the highest nodal average cost price of the market. Electricity generating companies, in fact, use the entire amount of coal capacity (1,564 MW) and 24% (612 MW) of the CCGT plants installed in the node to cover their electricity demand. All the clean power stations (namely hydro, renewable and nuclear) are dedicated to N-EIIs (see Tables 4.32 and 4.33 in Appendix 4.8 for electricity generation). As indicated in Table 4.7, this implies high emission costs for EIIs[10]. Dutch industries in Maastricht and in Zwolle are only supplied by CCGT stations; in Krimpen, instead, the set of the technologies given to industries is composed of renewable, nuclear, coal and CCGT.
Finally, German industries are mostly supplied by lignite (85% of the existing capacity), accompanied by nuclear (58%), hydro (51%), coal (9%) and renewable (1%): this is the reason why emission charges have the major weight in their prices (see Tables 4.31 and 4.35 in Appendix 4.8).

(ETS_R) and 36% (ETS_SAC) in Krimpen, 30% (ETS_R) and 45% (ETS_SCA) in Maastricht and, finally, 31% (ETS_R) and 45% (ETS_SAC) in Zwolle.

[9] Precisely 64% of the nuclear capacity installed corresponding to 29,002 MW (see Table 4.35 in Appendix 4.8).

[10] Note that generators in Gramme and in Merchtem have an opposite behaviour even though both nodes belong to the Belgian network. In the first location they dedicate clean technologies to EIIs; while in the second node clean technologies are exploited to supply N-EIIs. These apparently strange results are compatible with the non-convexity assumption introduced by the average cost price formulation. We found a different solution by assuming an alternative starting point for this nodal average cost model. The detailed results are presented in Section 4.6.

4.3.2 Impacts of the EU-ETS and Long-Term Contracts on N-EIIs

In the former Section, we have seen that both in the ETS_SAC and ETS_NAC cases, some EIIs lose, some others gain, even if their global power consumption raises with respect to the reference case ETS_R. These results are affected by the local capacity split and the technology mix used to supply industries. Generally speaking, the applications of these long-term contracts partially accommodate energy intensive industries. This implies a transfer of benefit from N-EIIs to EIIs.

Summer				
	NETS_R	**ETS_R**	**ETS_SAC**	**ETS_NAC**
Germany	19,852	18,746	18,564	18,575
France	22,127	22,097	22,127	19,889
Merchtem	1,322	1,287	1,281	1,282
Gramme	589	577	574	548
Krimpen	2,977	2,899	2,885	2,887
Maastricht	709	691	688	688
Zwolle	1,192	1,151	1,144	1,144
Total	**48,768**	**47,449**	**47,263**	**45,014**

Table 4.8: N-EIIs' Summer Electricity Demand under Different Fixed Capacity Scenarios in MWh

Winter				
MWh	**NETS_R**	**ETS_R**	**ETS_SAC**	**ETS_NAC**
Germany	47,434	47,936	46,190	47,175
France	44,524	44,538	44,376	42,903
Merchtem	4,382	4,496	4,118	4,374
Gramme	1,895	1,924	1,826	1,870
Krimpen	7,190	7,332	6,857	7,154
Maastricht	1,747	1,777	1,675	1,734
Zwolle	2,929	2,977	2,815	2,912
Total	**110,102**	**110,979**	**107,857**	**108,121**

Table 4.9: N-EIIs' Winter Electricity Demand under Different Fixed Capacity Scenarios in MWh

Tables 4.8 and 4.9 compare N-EIIs' hourly demand under the different scenarios studied. They refer respectively to the summer and the winter periods. Recall that the variations of their electricity consumption in NETS_R and ETS_R have already been explained in Section 4.2.3. The reader should also keep in mind that N-EIIs are still priced at the marginal production costs. It means that, in a transmission constraint free system, N-EIIs' prices are determined by the last power station used to produce their electricity augmented by the associated carbon cost. This implies that the split in capacity drives their power prices. Both in ETS_SAC and ETS_NAC models (with the exception of Merchtem in the ETS_NAC case), cheap and base-load technologies are reserved for energy intensive industries (see Tables 4.34 and 4.35). This is in line with an interpretation á la Ramsey-Boiteux. This theory deals with minimizing deadweight costs but can be interpreted as profit maximization (in accordance with the assumptions of our models). Because profits are related to the marginal supply costs and demand elasticity for a good, it follows that putting the highest price on the goods for which supply costs are higher and demand is least elastic will result in the maximal profit. In our average cost pricing models, we impose a capacity subdivision between the two consumer segments. This constraint can be assimilated to an additional cost faced by market agents. In order to minimize the loss of social welfare, generators charge the "costs" of the capacity sharing to N-EIIs' who represent the least elastic segment. This explains why the most expensive power plants are reserved for them[11]. Indeed, the methodology employed to split capacities and the carbon additional costs affect N-EIIs' prices of electricity that globally become more expensive than in the ETS_R case (compare Tables 4.24 and 4.25 with 4.26 and 4.27 in Appendix 4.8). This happens both in ETS_SAC and ETS_NAC models. In these cases, allowance prices are quite high and amount respectively to 28.48 €/ton and 28.21 €/ton.

In the ETS_SAC case, N-EIIs' summer prices are set by the CCGT plant cost increased by the corresponding carbon charge. In winter, instead, old gas and oil-based stations become again active in the Belgian node Merchtem and determine the prices (see Tables 4.29 and 4.30 in Appendix 4.8). Moreover, in this case, allowances are more expensive (+17%) than in ETS_R. The combination of these effects implies a cut of N-EIIs' power consumption both in summer (-0.4%) and in winter (-2.8%) with respect to the reference case.

The comparison between the ETS_NAC and the ETS_R scenarios confirms the tendency described above: N-EIIs face higher electricity prices and then reduce their power consumption (even in Merchtem). In particular, their demand cuts are 5.1% in summer and 2.6% in winter. In the ETS_NAC case, differences of electricity prices depend only on carbon cost, since CCGT plants are at the margin in each period both in the ETS_NAC and ETS_R scenarios (compare Tables 4.26 and 4.27 with Tables 4.32 and 4.33 in Appendix 4.8). In fact, in the reference case, allowances are 13% cheaper than in the nodal average cost case (24.44 €/ton vs 28.21 €/ton).

On the other side, the analysis of the two average cases ETS_SAC and ETS_NAC highlights that N-EIIs' demand assumes different trends in relation to the node and the period considered. In summer, the application of ETS_NAC contracts damages N-EIIs, since they lessen their electricity consumption by 4.76% with respect to ETS_SAC. This power reduction is mainly driven by the power demand cuts of N-EIIs located in France and in the Belgian node Gramme. In the other nodes, in fact, their consumption slightly changes or remains even identical. It means that both in France and in Gramme, the application of the ETS_NAC policy implies a transfer of surplus from N-EIIs to energy intensive industries. These results are in line with those discussed in the former Section: these are exactly the locations where the EIIs achieve their maximum benefit in the ETS_NAC case. This again results from the capacity splitting between the two consumer groups. Recall that in these two nodes a huge amount of nuclear and clean technologies is dedicated to industries[12]. In winter, the comparison of the two average cost pricing models shows a reverse situation. Apart French N-EIIs which still require less energy (-3.3%), in the other locations, they raise their electricity consumptions. Consequently the global balance is positive with a small increase of 0.2%.

From this analysis, it results that the long-term contracts negatively affect N-EII, since both in the ETS_SAC and ETS_NAC their global hourly electricity demand decreases with respect to the ETS_R case. Between the two average cost pricing policies, one should apply the one guaranteeing the higher consumers' benefit. The comparison of the hourly electricity demand of EIIs and N-EIIs does not help to take this decision since too many effects are involved. In Table 4.10 in Section 4.3.3 we indicate

[11] Apart from N-EIIs in Merchtem in the nodal average cost case.

[12] In France, industries are supply only by nuclear plants. They amount to 29,002 MW corresponding to 64% of the total nuclear capacity installed. In Gramme, industries are supplied by hydro (77%), renewable (65%), nuclear (100%) and CCGT (37%). See Tables 4.34 and 4.35 in Section 4.3.3.

the annual power demand by consumer group. Both in ETS_SAC and ETS_NAC the global electricity consumption is higher than in the reference scenario ETS_R. However, the single average cost pricing policy performs better than the ETS_NAC. In the ETS_SAC model industries globally increase their power demand by 5% with respect to their ETS_R level, which totally recovers the cut of of 2% of the respective N-EIIs' demand. This leads to a positive global effect. A similar reasoning holds also the ETS_NAC case, but the compensation between the industrial increased demand (+6% with respect to the ETS_R) and the drop of N-EIIs' consumption (-4% with respect to the ETS_R) is less efficient. This implies that ETS_SAC would be the consumers' preferable solution since it partially accommodates industries limiting the negative impacts on N-EIIs.

4.3.3 Allowance Prices and Capacity Allocation

As highlighted in the former Sections, a CO_2 allowance costs 24.44 €/ton, 28.48 €/ton and 28.21 €/ton respectively in the ETS_R, ETS_SAC and ETS_NAC scenarios. This means that in all cases emission constraint is tight. Moreover, in accordance with Reinaud ([43]) and Smeers ([49])' studies, these high carbon price invite power companies to modify their production mix and substitute coal with CCGT. This is confirmed by our results. The cost of emission allowances is influenced by electricity consumption. There is a positive correlation between emission level and electricity consumption. The higher is power demand and the higher is the amount of CO_2 emitted by the electricity generation process. Annual electricity consumptions[13] under the four scenarios studied are reported in Table 4.10. Without considering the NETS_R case, the ETS_SAC system allows consumers to comparatively have the highest electricity consumption. As already observed, the positive relative change of EIIs' demand prevails over N-EIIs' decreasing consumption. This results in a growth of the amount of electricity produced and, consequently, of the demand for allowances. Since we assume that carbon emissions are constantly capped, the allowance price becomes more costly in ETS_SAC than in the other cases. Specifically, the augments are 17% and 0.96% with respect to the ETS_R and ETS_NAC scenarios.

We know that, in the ETS_NAC model, EIIs' demand is higher than in ETS_SAC but this positive effect is annulled by the negative impact on N-EIIs. The final result is that the global annual demand in ETS_NAC is higher than in the ETS_R, but lower than in ETS_SAC. This explains why the CO_2 allowances cost less than in the single average cost case, but more than in the reference model.

	N-EIIs			**EIIs**	**Total**
	Summer	**Winter**	**Total**		
NETS_R	250	399	*649*	*598*	**1,248**
ETS_R	244	402	*646*	*531*	**1,177**
ETS_SAC	243	391	*634*	*555*	**1,189**
ETS_NAC	231	392	*623*	*565*	**1,188**

Table 4.10: Annual Electricity Demand under Different Fixed Capacity Scenarios in TWh (EIIs' Elasticity -1)

[13]The values of the annual electricity consumption reported in Table 4.10 are in line with the observed demand in 2005 (UCTE [54]). In accordance with our results, in the NETS_R case consumers require 553 TWh in Germany, 492 TWh in France, 81 TWh in Belgium and 115 TWh in the Netherlands. Their sum amounts to 1,242 TWh. In accordance with the UCTE data ([54]), in 2005, electricity consumptions by country were: 556 TWh in Germany, 482 TWh in France, 87 TWh in Belgium and 115 TWh in the Netherlands. Their sum gives 1,240 TWh.

Apart from the exception represented by EIIs in Merchtem, under both average cost pricing systems, power companies dedicate base-load and clean technologies to industries. In the ETS_SAC scenario, both in France and in the Belgian node Gramme, generators reserve only clean technologies (namely hydro, renewable and nuclear) for energy intensive industries (see Table 4.28). As expected, France plays an important role in this market segment, since it supplies almost all the industrial electricity demand that the bordering countries are not able to satisfy with their local power production. In France, the total capacity places at disposal of EIIs is larger than the amount that local industries really need. This especially holds for the nuclear power plants. In fact, the French industrial demand amounts to 19,408 MW which exactly corresponds to the 90% of the nodal amount of nuclear dedicated to EIIs (21,662 MW). By single average cost assumption, any industry can have access to this exceeding nuclear part. This helps the whole industrial sector, but has two obvious side effects: first French EIIs has to buy electricity at a higher price which damages their competitive position on the market studied. Second, French N-EII have a limited access to nuclear power. This indirectly affects their electricity prices, especially in winter, when the their consumption is higher. In particular, during the winter period, the capacity reserved for French N-EII is not sufficient to meet their entire demand and therefore they have to import more expensive electricity.

In the ETS_NAC, the proportion of base-load and clean technologies dedicated to industries change, but they remain comparatively high. In particular, they are: 10% of hydro, 62% of nuclear and 85% of lignite, plus just 1% of renewable. Tables 4.34 and 4.35 in Appendix 4.8 show the proportion by node and technology of capacities assigned to energy intensive industries respectively in the ETS_SAC and in the ETS_NAC scenarios.

4.4 Welfare Analysis

We conduct a welfare analysis in order to have a general overview of the effects that the EU-ETS and the application of long-term contracts have on the market players represented by generators, EIIs, N-EIIs and the TSO. We first present the mathematical formulation of the welfare function and the agents' profit and surplus equations and then we explain our numerical results. We also consider the case where EIIs behave in a less flexible way and their elasticity is set at -0.8. This additional test is introduced in order to prove the robustness of our models.

4.4.1 Profit and Surplus Equations

The social welfare is given by the difference between consumers' willingness to pay and generators' production costs as indicated in (4.1). It results from the combination of the surplus and profit equations of the four groups of agents operating in the market studied. We present them in the following by first considering the ETS_R case and then the average cost price models ETS_SAC and ETS_NAC.

Welfare in the ETS_R Model

$$\begin{aligned} \textit{welfare} = \; & \sum_{t,i}(a_i^{t,1} \cdot d_i^{t,1} \cdot hour^t - \frac{1}{2} \cdot b_i^{t,1} \cdot (d_i^{t,1})^2 \cdot hour^t) \\ & + \sum_{t,i}(a_i^{t,2} \cdot d_i^{t,2} \cdot hour^t - \frac{1}{2} \cdot b_i^{t,2} \cdot (d_i^{t,2})^2 \cdot hour^t) \end{aligned} \tag{4.1}$$

$$-\sum_{t,f,i,m} cost_{f,i,m} \cdot gp^t_{f,i,m} \cdot hour^t$$

Note that the emission trading does not affect the social welfare because the revenues from selling allowances compensates the cost of buying the same amount of allowances.

- **EIIs' Surplus (ETS_R)**

$$EIIs'surplus = \sum_{t,i}(a_i^{t,1} \cdot d_i^{t,1} \cdot hour^t - \frac{1}{2} \cdot b_i^{t,1} \cdot (d_i^{t,1})^2 \cdot hour^t) - \sum_{t,i} p_i^t \cdot d_i^{t,1} \cdot hour^t \tag{4.2}$$

- **N-EIIs' Surplus (ETS_R)**

$$NEIIs'surplus = \sum_{t,i}(a_i^{t,2} \cdot d_i^{t,2} \cdot hour^t - \frac{1}{2} \cdot b_i^{t,2} \cdot (d_i^{t,2})^2 \cdot hour^t) - \sum_{t,i} p_i^t \cdot d_i^{t,2} \cdot hour^t \tag{4.3}$$

- **Generators' Profit (ETS_R)**

$$Generators'profit = \sum_{t,f,i} p_i^t \cdot g_{f,i}^t \cdot hour^t - \sum_{t,f,i,m} cost_{f,i,m} \cdot gp^t_{f,i,m} \cdot hour^t \tag{4.4}$$

$$+\lambda \cdot (\sum_f E_f - \sum_{t,f,i,m} gp^t_{f,i,m} \cdot em_m \cdot hour^t)$$

Generators' profits account for the revenues of selling and the cost of producing electricity. Recall that in the reference case, there is no market segmentation and generators apply identical marginal prices to both consumer groups. Their profits are also affected by the opportunity emission costs which result from the trading of allowances. In the following Section we show how generators' profits vary in correspondence with the application of different allowance allocation methods. In particular, we consider the case of full grandfathering where E_f covers all the generators' emissions and the situation of full auctioning. Note that the first case is in line with what happened in the ETS period (2005-2007) at least in the countries included in our model, while the second scenario corresponds to what is foreseen by the new proposal of the ETS Directive. It is also possible to consider all the intermediate situations.

- **TSO's Profit (ETS_R)**

$$TSO's\ profit = \sum_{t,i}(d_i^{t,1} + d_i^{t,2} - \sum_f g^t_{f,i}) \cdot \sum_{t,i} p_i^t \cdot hour^t \tag{4.5}$$

The TSO operates indirectly by controlling the functioning of the transmission grid and guaranteeing the security and the reliability of the system. For this reason, we account for its merchandising profits in the computation of the social welfare. These profits accrue from selling injection and buying withdrawals from the network nodes.

Welfare in the ETS_SAC and ETS_NAC Models

The mathematical formulation of the welfare function in the single and in the nodal average cost pricing models differs from that in (4.1). Modifications depend on the assumptions of capacity share and demand segmentation characterizing the ETS_SAC and the ETS_NAC models. These two average cost models have identical welfare formulation represented by equation (4.6), even though one has to substitute the single with the nodal average cost prices in the agents' surplus and profit equations presented below. Moreover, in the nodal average cost case, TSO gains only by selling its service to the N-EIIs because industries are supplied only by local generators. Welfare equation is as follows:

$$\begin{aligned} welfare \;&=\; \sum_i (a_i^1 \cdot d_i^1 \cdot 8760 - \frac{1}{2} \cdot b_i^1 \cdot (d_i^1)^2 \cdot 8760) \\ &+ \sum_{t,i} (a_i^{t,2} \cdot d_i^{t,2} \cdot hour^t - \frac{1}{2} \cdot b_i^{t,2} \cdot (d_i^{t,2})^2 \cdot hour^t) \\ &- \sum_{f,i,m} cost_{f,i,m} \cdot gp_{f,i,m}^1 \cdot 8760 - \sum_{t,f,i,m} cost_{f,i,m} \cdot gp_{f,i,m}^{t,2} \cdot hour^t \end{aligned} \tag{4.6}$$

- **EIIs' Surplus (ETS_SAC)**

$$EIIs'surplus = \sum_i (a_i^1 \cdot d_i^1 \cdot 8760 - \frac{1}{2} \cdot b_i^1 \cdot (d_i^1)^2 \cdot 8760) - \sum_i p^1 \cdot d_i^1 \cdot 8760 \tag{4.7}$$

- **N-EIIs' Surplus (ETS_SAC)**

$$NEIIs'surplus = \sum_{t,i} (a_i^{t,2} \cdot d_i^{t,2} \cdot hour^t - \frac{1}{2} \cdot b_i^{t,2} \cdot (d_i^{t,2})^2 \cdot hour^t) - \sum_{t,i} p_{i,2}^t \cdot d_i^{t,2} \cdot hour^t \tag{4.8}$$

- **Generators' Profit (ETS_SAC)**

$$\begin{aligned} Generators'profit &= \sum_{f,i} pprod^1 \cdot g_{f,i}^1 \cdot 8760 + \sum_{t,f,i} p_i^{t,2} \cdot g_{f,i}^{t,2} \cdot hour^t \\ &- \sum_{f,i,m} cost_{f,i,m} \cdot gp_{f,i,m}^1 \cdot 8760 - \sum_{t,f,i,m} cost_{f,i,m} \cdot gp_{f,i,m}^{t,2} \cdot hour^t \\ &+ \lambda \cdot (\sum_f E_f - \sum_{f,i,m} gp_{f,i,m}^1 \cdot em_m \cdot 8760 - \sum_{t,f,i,m} gp_{f,i,m}^{t,2} \cdot em_m \cdot hour^t) \end{aligned} \tag{4.9}$$

- **TSO's Profit (ETS_SAC)**

$$TSO's\ profit = \sum_{t,i} (d_i^{t,2} - \sum_f g_{f,i}^{t,2}) \cdot \sum_{t,i} p_i^{t,2} \cdot hour^t + \sum_i ptrans^1 \cdot d_i^1 \cdot 8760 \tag{4.10}$$

4.4.2 Numerical Analysis

We start by analyzing Table 4.11 which summarizes the results presented in the previous Sections. The maximum social welfare is achieved under the NETS_R scenario which describes a perfectly competitive market without any carbon restriction. The introduction of the ETS regulation and thus of an additional economic constraint leads to a welfare loss of about 0.4%. Consumers bear the costs caused by this environmental policy: globally their surplus drops by 3%. EIIs are the most affected of the two consumer groups, since their surplus drops by 22%. This is a direct implication of the increased electricity prices[14]. N-EIIs face a 1% reduction of their surplus. These results are aligned with those reported in Table 4.10. In contrast, generators increase their profit by 16% in the case where allowances are fully grandfathered (see Table 4.11). This result is in line with the windfall profit phenomenon as described by Sijm et al. ([48]). Note that at line "Allowances" of Table 4.11, we report also the total value of the allowances, computed by multiplying the allowance price (24.44 €/ton in the ETS_R case) by the total emission cap (397 Mio ton p.a.). Note that generators' profit in case of full auctioning are obtained by subtracting the allowance value from the profit reported at line "Generators". Under this assumptions, generators' profits decrease by 23% with respect to the NETS_R level.

Billion €	**NETS_R**	**ETS_R**	**ETS_SAC**	**ETS_NAC**
EIIs	15.53	12.08	11.64	13.49
N-EIIs	130.87	129.35	124.65	120.20
Consumers	**146.40**	**141.43**	**136.29**	**133.69**
Generators	**25.22**	**29.25**	**32.94**	**36.78**
Allowances		*9.70*	*11.32*	*11.21*
TSO	**0.65**	**0.90**	**1.26**	**0.10**
Welfare	**172.27**	**171.58**	**170.49**	**170.58**

Table 4.11: Welfare under Different Fixed Capacity Scenarios (EIIs' Elasticity -1)

As described in Section 4.3, the application of the ETS_SAC and the ETS_NAC contracts has a global positive effect on electricity intensive industries. Their global power consumption has an increasing trend as described in Table 4.10. Nevertheless, both the ETS_SAC and the ETS_NAC do not completely accommodate industries. Relative changes in EIIs' demand vary per node in accordance with the average cost policy applied and the fuel mix adopted to produce electricity in each market location. We recall that under the single average cost price scenarios French EIIs reduce their electricity consumption by 22% with regard to the ETS_R case. The same happens also in the Belgian node Gramme, where the EIIs' demand cut is about 1%. The nodal surplus reflects these negative tendencies and the result is a global reduction of 4% of the EIIs' surplus with respect to the ETS_R level. This is due to the significant drop of 47% of the French industries' surplus which is not compensated by the industrial surplus' increases in the other nodes. N-EIIs are also negatively affected by the application of the single average cost pricing system. In fact, their surplus decrease by 4% with respect to their ETS_R level. This result is in line with their electricity consumption tendency

[14] Note that the high industrial demand elasticity enhances this effect.

as shown in Table 4.10. In this case, generators' profits are even 13% higher than in the ETS_R scenario. Note this happens when free allowances are distributed to generators and again results in windfall profits. In the case where generators have to buy all the allowances needed on the market (full auction), they face a 14% decrease of their profits with respect to case without environmental regulation.

The application of the nodal average cost pricing system relieves only industries in France and in the Belgian node Gramme[15]. The increases of EIIs' demand in these two nodes are so high that compensate the reduction of industrial consumptions in the other nodes. This effect is also captured by the surplus analysis. In fact, EIIs' total surplus is 12% higher than in the reference ETS_R case. In accordance with the results discussed in the previous Sections, N-EIIs decrease by 7% their global surplus with respect to the ETS_R model. This leads to a fall of 5% of the consumers' surplus. Generators face a situation that is similar to that described in the previous scenarios. Moreover, even when allowances are fully auctioned their profits are 1% higher than in the NETS_R. In this case, the profit increase is caused by the augment of electricity prices that, in turn, is due to the pass though of the carbon cost explain this outcome.

Between the two average cost pricing systems, the nodal one performs better and guarantees a higher global benefit.

Billion €	**NETS_R**	**ETS_R**	**ETS_SAC**	**ETS_NAC**
EIIs	18.12	14.28	14.47	15.33
N-EIIs	131.01	129.05	124.65	125.29
Consumers	**149.13**	**143.33**	**139.12**	**140.62**
Generators	**25.00**	**29.79**	**32.77**	**32.46**
Allowance Value		*10.44*	*11.31*	*11.30*
TSO	**0.66**	**0.94**	**1.26**	**0.78**
Welfare	**174.79**	**174.06**	**173.15**	**173.86**

Table 4.12: Welfare under Different Fixed Capacity Scenarios (EIIs' Elasticity -0.8)

	N-EIIs			**EIIs**	**Total**
	Summer	**Winter**	**Total**		
NETS_R	250	399	*650*	*586*	**1,236**
ETS_R	243	402	*645*	*524*	**1,169**
ETS_SAC	243	391	*634*	*554*	**1,188**
ETS_NAC	240	396	*636*	*556*	**1,191**

Table 4.13: Annual Electricity Demand under Different Fixed Capacity Scenarios in TWh (EIIs' elasticity -0.8)

In Tables 4.12 and 4.13, we report some of the results concerning the case where EIIs' demand elasticity equals -0.8. We avoid presenting all results and we concentrate our attention only on social

[15]Their electricity consumption increases respectively by 49% and 34% with respect to the ETS_SAC case, while increases are about 16% and 33% in comparison with the ETS_R.

welfare since it accounts for all market players' interactions. The final results does not change: the EU-ETS leads to additional costs that negatively affect the social welfare. Between the two average cost pricing system, the nodal average cost contracts perform better. However, the distribution of the benefit between the two consumer sectors changes because of a different capacity splitting. Generators' profits maintain the tendency observed in Table 4.11. They gain a lot when allowances are grandfathered, while their profits are under the NETS_R level in case of full auction.

4.5 Sensitivity Analysis

In this Section, we conduct a sensitivity analysis in order to check how industrial consumers' demand and emissions vary when one modifies the assumptions regulating the emission market. In our models, we endogenously determine carbon price and explore its modification under different electricity pricing mechanisms. Allowance price results from market equilibrium. We now simplify our models by directly introducing an exogenous allowance price. Consequently, one changes the prospective of the analysis. In fact, it is assumed that emission market is already cleared and then carbon price is fixed. Taking stock of this, generators decide their emission level. The structure of the average cost based contracts remains unchanged.

We test two cases where:

1. Allowance price is set at 20 €/ton ("AP20" hereafter)
2. Allowance price is set at 70 €/ton ("AP70" hereafter)

We consider an allowance price of 20 €/ton since it is the reference carbon cost used in several studies (McKinsey and Ecofys [33], Neuhoff et al. [37] and Reinaud [44]). We then fix an allowance price of 70 €/ton, because it seems to be the target suggested by the European Commission for the period 2013-2020 when a new emission and renewable commitments will be introduced (Energy Argus [1]). These tests require a small modification of our models. The exogenous allowance price dispenses with the need to explicitly model the emission market and implies that there is no need to retain the emission constraint in the model. Generators buy allowances on the market at exogenously given prices. In contrast with what we did before, we first define an allowance price and then we compute the amount of emissions generated.

Tables 4.14 and 4.15 report respectively the emission levels and the hourly amount of electricity required by EIIs under these two new allowance price scenarios. We compare them with the values obtained in the corresponding models with endogenous carbon price (AP-endo). Note that the endogenous allowance prices found in the previous sections are higher than 20 €/ton. A lower allowance price induces to a higher emission level. The reverse happens when we experiment an allowance price of 70 €/ton.

The contribution of CO_2 to the electricity price is relatively low when the allowance price is 20 €/ton. This encourages EIIs to increase their power demand with a consequent augment of the emission level. This happens in all scenarios studied and emissions raise respectively by 3% (ETS_R), 11% (ETS_SAC) and 7% (ETS_NAC) with respect to our cap of 397 Mio ton p.a. (see Table 4.14). Note that, even changing the allowance price, the nodal average cost model still guarantees the highest consumption level for industries.

The situation changes when we impose an emission cap of 70 €/ton. Industries drastically reduce their electricity demand in the ETS_R case. The cut computed with respect to the NETS_R level

		AP-ENDO	AP20	AP70
NETS_R	464			
ETS_R		397	407	104
ETS_SAC		397	441	256
ETS_NAC		397	423	256

Table 4.14: Emission Levels under Different Fixed Capacity and Allowance Price Scenarios in Mio ton p.a.

		AP-ENDO	AP20	AP70
NETS_R	68,294			
ETS_R		60,613	61,946	25,439
ETS_SAC		63,408	65,069	50,886
ETS_NAC		64,543	66,619	56,379

Table 4.15: EIIs' Electricity Demand under Different Fixed Capacity and Allowance Price Scenarios in MWh

amounts to 58% (see Table 4.15). Reductions are comparatively lower in the single and in the nodal average cost cases (respectively of -20% and -13%), since industries are "protected" by long-term contracts. In the reference scenario ETS_R, generators pass through this high carbon cost in the electricity price, making it very expensive. In the ETS_R, the summer prices paid by consumers (both EIIs and N-EIIs) are between 52.85 €/ton and 66.59 €/MWh[16], while in winter the electricity costs 82.76 €/MWh in all nodes, since the network is not congested. Note that this high fall of industrial electricity consumption partially depends on the -1 elasticity assumption used to describe industrial sector. In fact, also N-EIIs reduce their power demand, but cuts are much lower (-2% in summer and -9% in winter). However, the imposition of such a high allowance price would allow European Member States to comply with their emission targets. In accordance with our results reported in Table 4.14, emissions should reduce by 78% with respect the annual level (397 Mio ton p.a.) in the AP-endo version of ETS_R model. The low emission level of 104 Mio ton p.a. is both due to the drop in electricity consumption and the increased exploitation of clean technologies. In summer, a great part of the electricity required by consumers is covered by hydro, renewable and nuclear. Few CCGT plants are run in the Netherlands and these set the electricity price. In winter, clean technologies and CCGT are fully run and a small proportion of lignite plants are exploited in Germany.

These evidences show that allowance price is a tool suitable for achieving environmental targets, even though it can create social costs (additional burdens for consumers) and then inefficiencies.

In this AP70 scenario, the application of long-term contracts helps industries to reduce the negative impact deriving from this very restrictive environmental policy. In particular, the ETS_SAC allows EIIs to recover 59% of their lost demand (with respect of their NETS_R level), while in the ETS_NAC the gain is +72%. As already observed, the application of a such restrictive environmental policy implies a reduction of N-EIIs' benefit. This negative impact is more significant in winter than in summer (see Table 4.16 and 4.17). However, from an environmental point of view, the imposition of this high allowance price forces industries to reduce their carbon emissions and substitute dirty with

[16]This holds in all nodes, except in France and in Gramme where power prices are respectively equal to 4.50 €/MWh and 26.33 €/MWh.

Summer				
		AP-ENDO	**AP20**	**AP70**
NETS_R	48,768			
ETS_R		47,449	47,714	46,364
ETS_SAC		47,263	47,714	45,331
ETS_NAC		45,014	46,091	44,306

Table 4.16: N-EIIs' Summer Electricity Demand under Different Fixed Capacity and Allowance Price Scenarios in MWh

Winter				
		AP-ENDO	**AP20**	**AP70**
NETS_R	110,102			
ETS_R		110,979	110,719	100,974
ETS_SAC		107,875	107,943	99,562
ETS_NAC		108,121	106,392	99,376

Table 4.17: N-EIIs' Winter Electricity Demand under Different Fixed Capacity and Allowance Price Scenarios in MWh

more environmental-friendly technologies. This undoubtedly causes social costs that can be partially mitigated by long-term contracts.

4.6 Alternative Solutions to the Single and the Nodal Average Cost Models

We already highlighted that, under the nodal average cost pricing system, the capacity split in Merchtem and in Gramme is completely different, even though both nodes belong to the Belgian network.

	Without PM	**With PM**
Germany	31,065	30,740
France	19,408	19,205
Merchtem	4,511	4,464
Gramme	1,939	1,919
Krimpen	3,319	3,284
Maastricht	1,133	1,122
Zwolle	2,033	2,012
Total	**63,408**	**62,744**

Table 4.18: EIIs' Demand in the ETS_SAC Scenario With and Without the Preliminary Model in MWh

In the first location generators dedicate clean technologies to N-EIIs; while in the second node clean technologies are exploited to supply EIIs. These apparently strange results are compatible with the non-convexity assumption introduced by the average cost price formulation. For this reason, we run both the single and the nodal average cost cases without the preliminary model. This implies a change of the starting point of the algorithm of the average models. Under this new assumption, average cost models are still feasible, but their results are different. This means that non-convexity leads to disjoint solutions. In this Section, we present a sample of these alternative results.

	Hydro	**Renewable**	**Nuclear**	**Lignite**	**Coal**	**CCGT**	**Total**
Germany	1,268	2,840	8,615	10,462	705	3,355	**27,245**
France	3,338	1	22,095			887	**26,321**
Merchtem		20	1,076		745	1,424	**3,265**
Gramme	13	21	1,419				**1,453**
Krimpen		101	337		949	2,452	**3,839**
Maastricht		101				1,306	**1,407**
Zwolle		101					**101**
Total	**4,619**	**3,186**	**33,541**	**10,462**	**2,399**	**9,423**	**63,632**

Table 4.19: Existing Capacity dedicated to EIIs in the ETS_SAC Scenario Without the Preliminary Model in MW

In Table 4.19, we report the capacities dedicated to EIIs in the ETS_SAC case without the preliminary model (PM). Note that this capacity split is in line with that of the ETS_SAC scenario with preliminary model, even though it leads to a different consumers' demands. In the ETS_SAC case where the preliminary model is not implemented, the EIIs' demand is lower than in the ETS_SAC scenario with preliminary model (see Table 4.18). This is due to a higher single average cost price[17]. N-EIIs face an opposite situation. In fact, both with and without preliminary model, their marginal electricity prices are fixed by coal and CCGT plants respectively in summer and in winter. Nevertheless, the allowance price in ETS_SAC case without PM is 0.1% lower than in the ETS_SAC scenario with PM[18]. This reduces N-EIIs' electricity prices and induces them to increase their consumption in the ETS_SAC without PM.

	Without PM	**With PM**
Germany	26,913	26,644
France	29,002	26,633
Merchtem	2,176	3,866
Gramme	2,601	2,611
Krimpen	2,119	1,751
Maastricht	620	276
Zwolle	1,113	926
Total	**64,543**	**62,707**

Table 4.20: EIIs' Demand in the ETS_NAC Scenario With and Without the Preliminary Model in MWh

With the implementation of the ETS_NAC scenario without preliminary model, generators dedicate to EIIs the capacities indicated in Table 4.21. In particular, they change the allocation method in Merchtem by reserving renewable and part of the existing nuclear power plants to industries. This reduces by 23% the nodal average cost price faced by EIIs in Merchtem[19]. Globally, EIIs' electricity

[17]From 38.10 €/MWh with preliminary model to 38.54 without preliminary model.
[18]28.48 €/ton vs 28.44 €/ton.
[19]In particular, from a values of 59.79 €/MWh it drops to 44.08 €/MWh.

	Hydro	Renewable	Nuclear	Lignite	Coal	CCGT	Total
Germany	1,252	2,592	8,225	10,030	4,545		**26,644**
France	3,553	1	23,078				**26,633**
Merchtem		20	1,337		1,014	1,495	**3,866**
Gramme	13	21	2,204		121	251	**2,611**
Krimpen		101	132		754	764	**1,751**
Maastricht		101				234	**335**
Zwolle		101			139	685	**926**
Total	**4,819**	**2,938**	**34,977**	**10,030**	**6,574**	**3,429**	**62,766**

Table 4.21: Existing Capacity dedicated to EIIs in the ETS_NAC Scenario Without the Preliminary Model in MW

demand in the ETS_NAC case without PM is 3% lower than in the ETS_NAC model with PM (see Table 4.20). This is a direct consequence of the changed capacity split. Again, N-EIIs behave in an opposite way by increasing their electricity demand in both periods. Finally, the allowance price is identical in the ETS_NAC scenarios with and without PM.

4.7 Conclusions

The special contracts tested in this Chapter represent one response proposal of European EIIs to the new environment created by the EU-ETS. It implies a change of the pricing system to mitigate the increase of electricity prices caused by the EU-ETS. The results of the reference model presented in Section 4.2 confirm the current situation of electricity market: higher power prices which cause a cut of consumption, especially of energy intensive industries. In accordance with our input data, EIIs reduce their power demand by 11% in the ETS_R scenario. Generators profit from this situation, increasing their revenues by 16%.

In Section 4.3, we discuss the single and the nodal average cost pricing systems. These long-term contract policies have different effects on industries.
A common point is that average cost based pricing encourages industries to maintain their activities (here represented by consumption of electricity) with respect to the reference level at least under the condition retained in this model (exogenous capacities and efficient transmission market). In both average cost scenario, industries increase their electricity demand with respect to the reference case under ETS (ETS_R), even though they are not able to maintain the consumption level of the period before the ETS (NETS_R). This happens at the expense of N-EIIs who globally lessen their power demand. Nodal average cost pricing policy performs better than the single average cost contract since it enables industries to recover almost 51% of their lost demand against the 39% of the ETS_SAC model.

Nevertheless, neither the single nor the nodal average cost pricing mechanisms completely mitigate the burdens imposed by the EU-ETS on the industrial sector. The first policy (ETS_SAC model) negatively affects French and part of the Belgian electricity intensive users, who, instead, profit of the second average strategy (ETS_NAC model). In Germany, in Merchtem and in all Dutch nodes, industries face the opposite situation. The conclusion is that the impact of these long-term contracts on electricity intensive industries depends on the particular pricing scheme implemented (single or nodal) and on the fuel mix adopted to produce electricity in the countries where industries operate.

This is obviously the key factor, which defines power average cost based prices.

The welfare analysis conducted in Section 4.4 confirms the electricity market evolution presented in the Chapter. The application of the ETS implies a cut of the social benefit that it is partially recovered when the long-term contract policies are introduced. However, one faces a benefit transfer from N-EIIs to EIIs. We obtain similar results also changing the elasticity assumption of industrial demand. This means that our models are robust.

Finally, the high emission allowance price reveals the stress that the generation system is currently subject to. This suggests that investments in renewable power technologies, the improvement of the efficiency of the existing electricity units and the replacing of old power units are very needed. Looking at this problem requires capacity expansion model that we treat in Chapter 5. As shown by the sensitivity analysis in Section 4.5, allowance price represents a valid tool to tackle climate change since it may influence investments and technology mix choices.

4.8 Appendix: Further Results of the Four Scenarios under the Fixed Capacity Assumptions

In this Appendix, we show some additional results of the models discussed in this Chapter. This may help the reader to understand better the dynamics of the models presented. In particular, we show in details the electricity prices paid by N-EIIs, the technologies employed to supply the two consumer groups in the four scenarios and the proportions of the capacities dedicated to industries in the average cost pricing models.

Tables 4.22 and 4.23 report the electricity prices faced by N-EIIs in all scenarios respectively in summer and in winter. Recall that they are determined using a marginal cost based approach.

Summer				
	NETS_R	**ETS_R**	**ETS_SAC**	**ETS_NAC**
Germany	21.62	44.94	48.77	48.54
France	4.50	5.07	4.50	48.54
Merchtem	36.35	46.91	48.79	48.54
Gramme	19.09	27.79	29.87	48.54
Krimpen	36.35	46.91	48.79	48.54
Maastricht	36.35	46.91	48.65	48.54
Zwolle	32.15	46.07	48.41	48.54

Table 4.22: N-EIIs' Summer Electricity Prices under Different Fixed Capacity Scenarios in €/MWh

Tables 4.24 and 4.25 show the electricity generated by node and technology respectively in summer and in winter in the NETS_R case. Since in this scenario there is no market segmentation, the values reported in these Tables refer to the total amount of electricity produced for N-EIIs and EIIs. In summer, clean sources cover 65% of the electricity produced (namely hydro (6%), renewable (4%) and nuclear (55%)), followed by a 16% of coal, 15% of lignite and finally 3% of CCGT. In winter, nuclear remains the dominant source with a contribution of 36% to the total production. Hydro and renewable provide respectively 4% and 3% of the electricity consumed. Coal covers the 22% of electricity demanded, CCGT the 21%, lignite the 10%, oil the 2.6% and finally old gas the 0.4%.

Winter				
	NETS_R	**ETS_R**	**ETS_SAC**	**ETS_NAC**
Germany	51.48	47.36	61.67	53.60
France	47.48	47.36	48.79	61.78
Merchtem	57.26	47.36	80.31	57.95
Gramme	53.22	47.36	67.28	58.34
Krimpen	54.92	47.36	72.76	56.89
Maastricht	54.03	47.36	69.90	56.77
Zwolle	53.66	47.36	68.71	56.01

Table 4.23: N-EIIs' Winter Electricity Prices under Different Fixed Capacity Scenarios in €/MWh

Summer							
	Hydro	**Renewable**	**Nuclear**	**Lignite**	**Coal**	**CCGT**	**Total**
Germany	1,505	4,584	15,007	17,783	13,472		**52,352**
France	6,084	1	44,859				**50,944**
Merchtem		20	2,078		1,564	1,416	**5,079**
Gramme	13	21	2,204				**2,238**
Krimpen		101	337		3,128	1,309	**4,875**
Maastricht		101				890	**991**
Zwolle		101			482		**583**
Total	**7,602**	**4,930**	**64,485**	**17,783**	**18,646**	**3,616**	**117,063**

Table 4.24: Summer Electricity Generation in the NETS_R Scenario in MWh

Winter									
	Hydro	**Renewable**	**Nuclear**	**Lignite**	**Coal**	**CCGT**	**Gas**	**Oil**	**Total**
Germany	1,505	4,584	15,007	17,783	24,613	13,544			**77,036**
France	6,084	1	45,369	77	8,824	8,164		4,760	**73,279**
Merchtem		20	2,078		1,564	2,589	194	55	**6,500**
Gramme	13	21	2,204		979	1,207		194	**4,618**
Krimpen		101	337		3,128	4,432	528		**8,526**
Maastricht		101				2,917			**3,018**
Zwolle		101			482	4,834			**5,417**
Total	**7,602**	**4,930**	**64,995**	**17,860**	**39,590**	**37,687**	**722**	**5,009**	**178,396**

Table 4.25: Winter Electricity Generation in the NETS_R Scenario in MWh

Tables 4.26 and 4.27 show the electricity production when an environmental policy is implemented. As highlighted in Section 4.2.2, the EU-ETS induces generators to abandon inefficient technologies (namely old gas and oil-based plants) and reduce the exploitation of dirty coal stations. These changes influence electricity prices, especially in winter as described in Section 4.2.2. In summer, clean technology covers 71% of the total electricity demand[20], followed by 16% of lignite, 8% of coal and 4% of CCGT. In winter, the production mix is composed of nuclear (38%), coal (23%), CCGT (21%), lignite (10%), hydro (4%) and renewable (3%).

Summer							
	Hydro	**Renewable**	**Nuclear**	**Lignite**	**Coal**	**CCGT**	**Total**
Germany	1,505	4,584	15,007	17,783	3,584		**42,464**
France	6,084	1	45,369				**51,454**
Merchtem		20	2,078		1,564	1,342	**5,004**
Gramme	13	21	2,204				**2,238**
Krimpen		101	337		3,128	1,266	**4,832**
Maastricht		101				1,385	**1,486**
Zwolle		101			482		**583**
Total	**7,602**	**4,930**	**64,995**	**17,783**	**8,758**	**3,992**	**108,062**

Table 4.26: Summer Electricity Generation in the ETS_R Scenario in MWh

Winter							
	Hydro	**Renewable**	**Nuclear**	**Lignite**	**Coal**	**CCGT**	**Total**
Germany	1,505	4,584	15,007	17,783	24,613	12,471	**75,963**
France	6,084	1	45,369	77	8,824	8,164	**68,519**
Merchtem		20	2,078		1,564	2,589	**6,251**
Gramme	13	21	2,204		979	1,207	**4,424**
Krimpen		101	337		3,128	4,432	**7,998**
Maastricht		101				2,917	**3,018**
Zwolle		101			482	4,834	**5,417**
Total	**7,602**	**4,930**	**64,995**	**17,860**	**39,590**	**36,614**	**171,592**

Table 4.27: Winter Electricity Generation in the ETS_R Scenario in MWh

In the average cost pricing models, generators supply the two market segments by using dedicated capacities. Table 4.28 reports the hourly electricity generation for EIIs in the ETS_SAC scenario. Note that in each hour, generators run the plants reserved for industries at full capacity in order to guarantee the energy balance of industrial market segment. It means that the values reported in Table 4.28 correspond exactly to the capacities dedicated to EIIs in the different locations of the network.

The amount of electricity required by N-EIIs is higher in winter than in summer. Tables 4.29 and 4.30 report the plants run to cover N-EIIs' consumption in each period. Globally, the new capacities dedicated to N-EIIs amount to 113,828 MW, even though their total demand in winter is 5% lower (107,857 MW). As illustrated by Table 4.30, in the Belgian node Merchtem, gas and oil-fired stations are fully exploited in winter in order to cover the N-EIIs' electricity demand. Nevertheless, generators

[20]The contribution of nuclear, hydro and renewable are respectively 60%, 6% and 5%.

	Hydro	Renewable	Nuclear	Lignite	Coal	CCGT	Total
Germany	1,359	3,165	8,998	11,081		2,825	**27,427**
France	3,180	1	21,662				**24,844**
Mechtem		20	1,167		847	1,295	**3,330**
Gramme	13	21	1,495				**1,529**
Krimpen		101	337		1,007	2,736	**4,181**
Maastricht		101				1,895	**1,996**
Zwolle		101					**101**
Total	**4,552**	**3,511**	**33,659**	**11,081**	**1,854**	**8,751**	**63,408**

Table 4.28: Hourly Electricity Generated for EIIs in the ETS_SAC Scenario in MWh

import 23% of the demand needed to cover NEIIs' local demand. A similar reasoning holds for France which avoid to exploit its old gas and oil technologies and prefer import electricity to supply N-EIIs.

Summer							
	Hydro	**Renewable**	**Nuclear**	**Lignite**	**Coal**	**CCGT**	**Total**
Germany	146	1,419	6,009	6,702	0	6,773	**21,050**
France	2,904	0	18,229	0	0	0	**21,132**
Merchtem	0	0	911	0	415	1,294	**2,620**
Gramme	0	0	709	0	0	0	**709**
Krimpen	0	0	0	0	0	1,696	**1,696**
Maastricht	0	0	0	0	0	57	**57**
Zwolle	0	0	0	0	0	0	**0**
Total	**3,050**	**1,419**	**25,858**	**6,702**	**415**	**9,820**	**47,264**

Table 4.29: Summer Electricity Generated for N-EIIs in the ETS_SAC Scenario in MWh

Table 4.31 reports the electricity produced to cover EIIs' demand in tghe ETS_NAC scenario. In accordance with the nodal energy balance imposed, EIIs' demand in each node has to be covered by local production. For this reason, the capacities indicated in Table 4.31 correspond exactly to the technologies devoted to EIIs in each location. This explains why nodal average cost price are so different over node. As already said, the local technological mix affects average cost price and then industrial power demand in each node. This is particularly evident in the Belgian node Merchtem.

The remaining power plants are exploited to satisfy N-EIIs' electricity request in the ETS_NAC scenario. As indicated in Tables 4.32 and 4.33, both in summer and in winter CCGT are the last power stations to be run, even though they could also be supplied by other sources like old gas and oil. Generators refuse to utilize these technologies because of their high emission factors.

Finally, Tables 4.34 and 4.35 report the proportions of the existing capacities dedicated to EIIs. The remaining technologies are adopted to cover N-EIIs' power demand. As already discussed, base-load and clean technologies are mainly devoted to industries while a great proportion of N-EIIs' demand is covered by coal, CCGT, old gas and oil-based power stations. These technologies are more costly in terms of fuel and emissions. This affects N-EIIs' electricity prices. Moreover, both in the ETS_SAC and ETS_NAC models, the capacities assigned to industries exactly equals their electricity need; while the power plants reserved for N-EIIs are usually above their winter demand. For this reason, generators do not exploit old gas and oil based plants to supply them.

Winter									
	Hydro	**Renewable**	**Nuclear**	**Lignite**	**Coal**	**CCGT**	**Gas**	**Oil**	**Total**
Germany	146	1,419	6,009	6,702	24,613	10,719	0	0	**49,609**
France	2,904	0	23,707	77	8,461	6,255	0	0	**41,403**
Merchtem	0	0	911	0	717	1,294	194	55	**3,171**
Gramme	0	0	709	0	979	1,207	0	0	**2,895**
Krimpen	0	0	0	0	2,121	1,696	625	0	**4,442**
Maastricht	0	0	0	0	0	1,022	0	0	**1,022**
Zwolle	0	0	0	0	482	4,834	0	0	**5,316**
Total	**3,050**	**1,419**	**31,336**	**6,779**	**37,372**	**27,027**	**819**	**55**	**107,857**

Table 4.30: Winter Electricity Generated for N-EIIs in the ETS_SAC Scenario in MWh

	Hydro	**Renewable**	**Nuclear**	**Lignite**	**Coal**	**CCGT**	**Total**
Germany	773	28	8,779	15,132	2,200		**26,913**
France			29,002				**29,002**
Merchtem					1,564	612	**2,176**
Gramme	10	14	2,204			373	**2,601**
Krimpen		17	337		778	986	**2,119**
Maastricht						620	**620**
Zwolle						1,113	**1,113**
Total	**783**	**60**	**40,322**	**15,132**	**4,542**	**3,705**	**64,543**

Table 4.31: Hourly Electricity Generated for EIIs in the ETS_NAC Scenario in MWh

Summer							
	Hydro	**Renewable**	**Nuclear**	**Lignite**	**Coal**	**CCGT**	**Total**
Germany	733	4,556	6,228	2,651	2,273		**16,440**
France	6,084	1	16,367	77			**22,529**
Merchtem		20	2,078				**2,098**
Gramme	3	7					**10**
Krimpen		84					**84**
Maastricht		101					**101**
Zwolle		101				3,649	**3,750**
Total	**6,820**	**4,871**	**24,673**	**2,728**	**2,273**	**3,649**	**45,014**

Table 4.32: Summer Electricity Generated for N-EIIs in the ETS_NAC Scenario in MWh

Winter							
	Hydro	**Renewable**	**Nuclear**	**Lignite**	**Coal**	**CCGT**	**Total**
Germany	733	4,556	6,228	2,651	22,413	13,544	**50,123**
France	6,084	1	16,367	77	8,824	8,164	**39,517**
Merchtem		20	2,078			1,977	**4,076**
Gramme	3	7			979	834	**1,823**
Krimpen		84			2,350	3,446	**5,880**
Maastricht		101				2,297	**2,398**
Zwolle		101			482	3,721	**4,304**
Total	**6,820**	**4,871**	**24,673**	**2,728**	**35,048**	**33,982**	**108,121**

Table 4.33: Winter Electricity Generated for N-EIIs in the ETS_NAC Scenario in MWh

	Hydro	**Renewable**	**Nuclear**	**Lignite**	**Coal**	**CCGT**
Germany	90%	69%	60%	62%		21%
France	52%	94%	48%			
Merchtem		100%	56%		54%	50%
Gramme	100%	100%	68%			
Krimpen		100%	100%		32%	62%
Maastricht		100%				65%
Zwolle		100%				
Total	60%	71%	52%	62%	5%	23%

Table 4.34: Proportion of Existing Capacity Dedicated to EIIs in the ETS_SAC

	Hydro	**Renewable**	**Nuclear**	**Lignite**	**Coal**	**CCGT**	**Old gas**
Germany	51%	1%	58%	85%	9%		
France			64%				
Merchtem					100%	24%	
Gramme	77%	65%	100%			31%	100%
Krimpen		17%	100%		25%	22%	
Maastricht						21%	
Zwolle						23%	
Total	**10%**	**1%**	**62%**	**85%**	**11%**	**10%**	**5%**

Table 4.35: Proportion of Existing Capacity Dedicated to EIIs in the ETS_NAC

Chapter 5

Average Cost Based Contracts under Investment Assumptions

5.1 Introduction

In this Chapter, we still study the indirect impact of the EU-ETS on energy intensive industries. Taking stock of the reference and average cost based contract models developed in Chapter 3, we introduce an investment assumption. We suppose that generators may build new power stations in addition to the already existing capacity. Consequently, capacity becomes an endogenous variable of the model. Moreover, thanks to this investment hypothesis, the modelling of the long-term average cost based contracts becomes more realistic. In this new scenario, we assume to operate in the (2008-2012) phase of the first commitment period of the EU-ETS and hence adopt a more restrictive emission target. This induces a restructuring of generation infrastructure through investments.

Investment policy in the electricity sector is usually associated with the reliability issue. According to the definition given by Stoft ([51]), a system is considered reliable if it *has adequate installed capacity and is operated within security limits.* Smeers in [49], taking as references recent studies conducted by the ETSO ([19]) and UCTE ([55]), highlights that the European generation system may lack capacity in 2012 or, in a more optimistic case, in 2015 depending on the investment scenario considered. These studies agree with the fact that the existing electricity generation units should be renewed in accordance with not only the IPCC Directive 96/61/EC[1], but also the CO_2 world restrictions. For this reason, the European Commission is insisting on the need of investing in renewable capacity as indicated in its proposal for the new Directive regulating the after 2012 EU-ETS program. However, the uncertainty characterizing the after 2012 ETS period leads to higher capital costs and complicate investment choices, especially for energy intensive industries[2]. It is well recognized that the methodology applied to allocate allowances affects investment decisions. Neuhoff et al. ([37]) state that *certain modes of free allowance allocation can create incentives of some significance for*

[1] The IPPC Directive sets common rules for permitting and minimizing pollution of industrial installations. Operators of industrial facilities involved in the IPPC Directive are required to obtain an environmental permit from the authorities in the EU countries. The Directive aims to guarantee a high protection level of the environment under all its aspects (air, water, land, etc.). Secondly, the permit conditions must to be based on the *Best Available Techniques* (BAT), i.e. the most effective technology developed on the market, taking into consideration its costs and its advantages.

[2] See Article 10a point 8 of the new proposal of ETS Directive.

rational firms in a competitive market to adjust decisions on operation, investment and closure in order to influence future allocation, especially if they are based on an updating procedure. They show using both a theoretical and an empirical approach, that allocations of free allowances based on some updating techniques create perverse incentives and do not encourage generators to close old plants to switch over to more efficient and environmental-friendly technologies. This is the case of free allocation approaches based on emissions and fuel benchmarks. For instance, generators might invest in carbon intensive facilities if they know in advance that future allowance distributions will be proportional to emissions or fuel choices made today. This leads to a paradoxical situation, where a coal based technology would become more profitable under the EU-ETS than before. Indeed, this is against the objective of any climate policy. This reasoning holds both for incumbents and new entrants[3]. As already discussed in the previous Chapters, auctions and one-off free allocation of allowances are the most efficient solutions since they limit distortions (compare Hepburn et al. [27] and Neuhoff et al. [37]). This is what is envisaged by the new ETS Directive proposal and corresponds to the approach that we adopt in our analysis.

Considering this complex framework, we simultaneously analyze an investment problem and the long-term contracts presented in Chapters 3 and 4 by assuming a fixed amount of allowances allocated once for all[4]. The main structure of the models does not change with respect to that adopted in Chapter 3: we only adjust them to account for the investment assumption. Investments are undertaken in accordance with national law in terms of acceptable technologies and fuel availability. Recall from Chapter 2 that generators can invest in new nuclear plants only in France; lignite can be exploited only in Germany and finally hydro power is not available in the Netherlands. Investments in nuclear capacity would certainly be an effective instrument to tackle climate changes (see results in Chapter 6); but their penetration is hindered by government and public aversions. The Communication of Commission to the European Council and Parliament COM/2006/0844 gives an overview of the current position assumed by Member States in matter of nuclear energy. In particular, France and Finland have expressed their intent to build new nuclear reactors; the Netherlands have re-opened the debate on a possible extension of the life of the existing nuclear installation. Belgium and Germany are undertaking a progressive abandon of nuclear units, even though Germany is trying to delay their decommissioning (Energy Argus [1]).

According to Article 11 of Directive 2003/87/EC, *when deciding upon the allocation, Member States shall take into account the need to provide access to allowances for new entrants.* However, our goal is to study the interaction between investments and special contracts and, for this reason, we suppose that allowances are auctioned and this holds also for new power installations. This is in line with the long-term position assumed by the European Commission in the proposed EU-ETS Directive for the period (2013-2020).

This Chapter is subdivided into two main parts. In a first Section, we present the structure of the models. As already mentioned, these are extensions of the models described in Chapter 3 and thus many assumptions are common. Also variables and parameters are mostly identical. We slightly modify the structure of the investment models in order to account for the market modifications induced by the construction of new plants. Changes mainly concern generators' optimization problem, since

[3] In accordance with the definition given in Article 3 of Directive 2003/87/EC, a new entrant is either a new installation or a new piece of equipment that increases the capacity of an existing installation. Extensions of existing piece of equipment are not included in this category.

[4] We take this assumption, since our scope departs from modelling economic distortions caused by different allocation methods.

they have to account for the additional investment costs. The N-EIIs and EIIs' surplus maximization problems do not vary. The same reasoning holds also for modelling of the energy balance and network constraints. In contrast, the emission trade market include the amount of CO_2 generated by new power plants. Moreover, we reduce the emission cap of the power market studied. It now amounts to about 359 Mio ton p.a. as indicated in Table 2.8 of Chapter 2.

Like in Chapter 3, we proceed step by step. We first consider a reference model describing a perfectly competitive market where generators invest and apply identical marginal cost prices to N-EIIs and EIIs. We then introduce the formulation of the single and the nodal average cost pricing system models. Capacity spitting and market segmentation are the two assumptions on which these long-term contract models rely. Note that in these cases, generators have to decide how sharing both new and old capacities between the two consumer groups. In order to avoid repetitions, we describe the parts of the models that are subject to modifications. As in Chapter 3, we first present the models in agent optimization form (nonlinear programming) and then we state the corresponding complementarity conditions that we solve using PATH in GAMS.

In the second part of this Chapter, we focus our attention on the analysis of these results and the non-convexity problems caused by the average cost pricing system. Finally, we conclude with a welfare and a sensitivity analysis.

5.2 Reference Investment Model

The reference investment case here presented (ETS_IR hereafter) is similar to the basic model described in Section 3.2. We still assume a perfectly competitive market where generators supply N-EIIs and EIIs. All market players are price-takers and desire to maximize their benefits (profit and surplus). The absence of demand segmentation allows generators to apply identical local marginal prices to both consumer groups. These are still computed in accordance with the $PTDF$ representation of the network. When a grid congestion arises, power prices become different over nodes because of the impacts of transmission costs.

Since we want to test the effects on the EU-ETS on investment choices, we introduce an emission balance constraint. The carbon market considered is restricted to the power sector and it does not include CO_2 emitted by industrial sectors.

We present only the power companies' optimization problem and the new emission constraint. Consumers' models and transmission constraints are as in Section 3.2. The new variables adopted to describe the power companies' problem are listed below:

1. **Variables**

Generators

- $g^t_{f,i}$ Hourly power sold at node i by generator f in each period t in MW;
- $gpc^t_{f,i,m}$ Hourly generated electricity by old unit m owned by generator f at node i in each period t in MW;
- $gpi^t_{f,i,m}$ Hourly generated electricity by new unit m owned by generator f at node i in each period t in MW;
- $investment_{f,i,m}$ MW of new unit m built by generator f at node i;

- $\nu c^t_{f,i,m}$ Dual variable representing the marginal capacity cost (scarcity rent) of old unit m owned by generator f at node i in each period t;
- $\nu i^t_{f,i,m}$ Dual variable representing the marginal capacity cost (scarcity rent) of new unit m owned by generator f at node i in each period t;
- $\eta^t_{f,i}$ Dual variable representing the marginal generation cost by generator f and node i in each period t.

The other variables remain unchanged as well as sets and parameters.

5.2.1 Generators' Profit Maximization Model

In this model, power companies have the possibility to invest in new capacities. They can either use the already existing technologies or the new power stations to produce electricity. Companies take this decision so as to maximize profits. The variables $gpc^t_{f,i,m}$ and $gpi^t_{f,i,m}$ indicate respectively the electricity generated by old and new power stations. The profit function (5.1) includes the annual revenues, gained by selling electricity to consumers, the variable production costs ($fuel_{f,i,m}$ and $cost_{f,i,m}$) and the fixed charges of investments in new capacity ($FC\_annual_{f,i,m}$). We also include the term $E_f \cdot \lambda$ in the objective function (5.1). The variable λ represents the allowance price, while the parameter E_f is the amount of free allowances given to generators. Since we assume that allowances are given once for all, auctioning and grandfathering simply imply a transfer of benefit from public authorities to the other market players. For this reason, in our models, we assume full auctioning and the parameter E_f does not appear in the generators' complementarity problem[5]. Recall that in case of auctioning, allowances represent real costs, while they become opportunity costs under grandfathering assumptions[6].

As before, the parameter $hour^t$ corresponds to duration in hours of the two period modelled.

$$\begin{aligned}\textbf{Max} \ & \sum_{t,i} p^t_i \cdot g^t_{f,i} \cdot hour^t - \sum_{t,i,m} cost_{f,i,m} \cdot gpc^t_{f,i,m} \cdot hour^t \\ & - \sum_{t,i,m} fuel_{f,i,m} \cdot gpi^t_{f,i,m} \cdot hour^t \\ & - \sum_{i,m} FC\_annual_{f,i,m} \cdot investment_{f,i,m} \\ & + \lambda \cdot (E_f - \sum_{t,i,m} gpc^t_{f,i,m} \cdot em_m \cdot hour^t - \sum_{t,i,m} gpi^t_{f,i,m} \cdot em_m \cdot hour^t)\end{aligned} \tag{5.1}$$

subject to:

$$0 \leq g^t_{f,i} \leq \sum_m gpc^t_{f,i,m} + \sum_m gpi^t_{f,i,m} \qquad (\eta^t_{f,i}) \qquad \forall\ t,f,i \tag{5.2}$$

$$0 \leq gpc^t_{f,i,m} \leq G_{f,i,m} \qquad (\nu c^t_{f,i,m}) \qquad \forall\ t,f,i,m \tag{5.3}$$

[5]However, in the welfare analysis, we show how generators' profits charge under the assumptions of full auctioning and grandfathering.

[6]Emission opportunity costs may have a positive or a negative impact on profits, depending on the generators' position on the carbon market.

$$0 \leq gpi^t_{f,i,m} \leq investment_{f,i,m} \qquad (\nu i^t_{f,i,m}) \qquad \forall\, t, f, i, m \tag{5.4}$$

Conditions (5.2), (5.3) and (5.4) are the restrictions imposed on electricity production. The first inequality (5.2) states the production condition: the sum of electricity produced by old $gpc^t_{f,i,m}$ and new $gpi^t_{f,i,m}$ plants has to be greater or equal the amount of electricity sold $g^t_{f,i}$. The dual variable $\eta^t_{f,i}$ pairing this balance condition represents the marginal production costs.

Inequalities (5.3) and (5.4) introduces capacity constraints. Condition (5.3) refers to old ($G_{f,i,m}$) capacities, while (5.4) considers new power plants ($investment_{f,i,m}$). Note that $G_{f,i,m}$ is a parameter and $investment_{f,i,m}$ is a variable. By construction, each company f is free to choose where investing and which technology adopting. This implies that investments depend on technology m and location i, but not on generator f. Market equilibrium determines the total amount of new capacity needed. Both capacity constraints are matched with dual variables ($\nu c^t_{f,i,m}$ and $\nu i^t_{f,i,m}$ respectively) that correspond to the marginal capacity costs of each plant. All the variable included in the model are supposed to be non-negative. The complementarity formulation of generators' optimization problem is obtained by stating the first order conditions of optimization problem (5.1)-(5.4) with respect to all the variable included[7].

$$0 \leq -p^t_i + \eta^t_{f,i} \perp\, g^t_{f,i} \geq 0 \qquad \forall\, t, f, i \tag{5.5}$$

$$0 \leq cost_{f,i,m} + em_m \cdot \lambda + \nu c^t_{f,i,m} - \eta^t_{f,i} \perp gpc^t_{f,i,m} \;\geq 0 \qquad \forall\, t, f, i, m \tag{5.6}$$

$$0 \leq fuel_{f,i,m} + em_m \cdot \lambda + \nu i^t_{f,i,m} - \eta^t_{f,i} \perp gpi^t_{f,i,m} \;\geq 0 \qquad \forall\, t, f, i, m \tag{5.7}$$

$$0 \leq G_{f,i,m} - gpc^t_{f,i,m} \perp\, \nu c^t_{f,i,m} \geq 0 \qquad \forall\, t, f, i, m \tag{5.8}$$

$$0 \leq investment_{f,i,m} - gpi^t_{f,i,m} \perp\, \nu i^t_{f,i,m} \geq 0 \qquad \forall\, t, f, i, m \tag{5.9}$$

$$0 \leq \sum_m gpc^t_{f,i,m} + \sum_m gpi^t_{f,i,m} - g^t_{f,i} \perp\, \eta^t_{f,i} \geq 0 \qquad \forall\, t, f, i \tag{5.10}$$

$$0 \leq FC\_hour_{f,i,m} - \sum_t \nu i^t_{f,i,m} \cdot proportion^t \perp\, investment_{f,i,m} \geq 0 \qquad \forall\, t, f, i \tag{5.11}$$

These conditions are similar in meaning and formulation to the complementarity conditions (3.4)-(3.7) presented in Section 3.2 of Chapter 3. In particular, (5.5) is identical to (3.4) in the NETS_R model. Recall it states that generators produce electricity $g^t_{f,i}$ only when their marginal production costs $\eta^t_{f,i}$ equalize the marginal electricity price p^t_i set on the energy market. The nodal electricity prices p^t_i accounts for the congestion costs and are determined following the approach described in Section 3.2.4 of Chapter 3. Variable $\eta^t_{f,i}$ assumes positive values when constraint (5.10) is binding, i.e. when the total amount of electricity produced ($gpc^t_{f,i,m}$+$gpi^t_{f,i,m}$) equals the power sold $g^t_{f,i}$. Fuel costs of the existing power plants are represented by the parameter $cost_{f,i,m}$, while those of the new capacities are indicated by $fuel_{f,i,m}$. We use a different nomenclature in order to distinguish the two cases, but they assume identical values in our data[8]. The term $em_m \cdot \lambda$ defines the emission opportunity cost, where em_m and λ are respectively the emission factor by technology and the allowance price. Finally, $\nu c^t_{f,i,m}$ and $\nu i^t_{f,i,m}$ are the marginal values associated with the old and new capacities respectively. All these variables appear in conditions (5.6) and (5.7). Marginal production costs

[7]Note that complementarity conditions are based on the minimization version of the optimization model (5.1)-(5.4).

[8]Recall that in order to simplify our data set and facilitate the understanding of our results, we assume that old and new capacities have identical cost structure by technology. This holds both for the variable and the fixed cost. However, our models allow also the case where new power plants are more efficient than existing ones.

$\eta^t_{f,i}$ implicitly define the equality between the sum of fuel ($cost_{f,i,m}$, $fuel_{f,i,m}$), emissions ($em_m \cdot \lambda$) and capacity ($\nu c^t_{f,i,m}$, $\nu i^t_{f,i,m}$) costs of old and new capacities. Dual variables $\nu c^t_{f,i,m}$ and $\nu i^t_{f,i,m}$ are matched with (5.8) and (5.9) defining the capacities constraints and assume positive values when plants m are run at their full capacities $G_{f,i,m}$ and $investment_{f,i,m}$. Finally, condition (5.11) is used to regulate investment decisions. If the scarcity rent $\nu i^t_{f,i,m}$ is greater than the fixed costs, it means that the level of installed capacity is not sufficient to satisfy the demand. As stated by (5.11), it never happens at equilibrium. Otherwise if the scarcity rent is smaller than the fixed costs, it is not profitable to invest. Investments assume the right level only when scarcity rent equals the fixed costs. In (5.11), we account for the hourly fixed costs $FC\_hour_{f,i,m}$ per company f, node i and technology m since the scarcity rent $\nu i^t_{f,i,m}$ is expressed in hour. This variable depends on time t and hence we multiply it by the parameter $proportion^t$, which defines the proportion of the duration of each period.

5.2.2 Emission Market

The emission market is modelled by condition (5.12). CAP represents the emission cap of 359 Mio ton p.a., as stated in Table 2.8 of Chapter 2. Since we assume that new power stations do not receive any allowances for free, CAP accounts only for the carbon emission of the already installed capacities. This emission constraint means that the total amount of CO_2 emitted by power plants cannot exceed this total cap. Emissions are simply computed by product of the quantity of electricity annually produced by old ($gc^t_{f,i,m} \cdot hour^t_i$) and new ($gi^t_{f,i,m} \cdot hour^t_i$) plant m and the corresponding emission factor em_m. The parameter $hour^t$ still defines the duration in hours of each period. This duration is identical in each node i and hence is not indexed by i. When emission constraint is tight, the variable λ is positive and defines the emission market clearing price.

$$\sum_{t,f,i,m} gpc^t_{f,i,m} \cdot em_m \cdot hour^t + \sum_{t,f,i,m} gpi^t_{f,i,m} \cdot em_m \cdot hour^t \leq CAP \quad (\lambda) \tag{5.12}$$

The complementarity form of condition (5.12) is as follows:

$$0 \leq CAP - \sum_{t,f,i,m} gc^t_{f,i,m} \cdot em_m \cdot hour^t_i - \sum_{t,f,i,m} gi^t_{f,i,m} \cdot em_m \cdot hour^t_i \perp \lambda \geq 0 \tag{5.13}$$

5.3 Average Cost Pricing Models under Investment Assumptions

The key assumption underlying these case studies is that energy intensive industries conclude long-term contracts with generators in order to hedge the volatility of electricity prices and have a secure supply. These contracts allow them to have an indirect access to part of both new and old power stations installed in the market. Since there is no interaction between EIIs and N-EIIs, generators have to decide the proportion of the whole available capacity to reserve for the two market segments. The structure of these new single and the nodal average cost based models is similar to those of ETS_SAC and ETS_NAC cases. Industries still pay the full average generation cost associated with the capacity that generators dedicate to them. In contrast, N-EIIs are priced at the marginal cost of producing electricity.

Recall that the average cost pricing technique ruins the convexity properties of reference model and may create computational difficulties. As already explained in Chapter 3, we subdivide each average cost based model into two sub-problems. We first simulate a scenario of a perfectly competitive market, where EIIs and N-EIIs buy electricity at marginal cost price and share the available capacity. This preliminary model is characterized by capacity splitting, market segmentation and investments. Preliminary and average cost based models differ only for the methodology adopted to price energy intensive industries: a marginal cost approach in the former case and an average cost one in the latter. All the other assumptions are common, included the formulation of the consumers' optimization problems. The outcome of the preliminary model is used as a starting point for the solution to the two (single and nodal) associated average cost problems. This is the methodology adopted to possibly mitigate infeasibility problems. However, besides the investment assumptions, single a nodal average cost price problems are feasible even without running the preliminary model. The solutions of the average cost models with and without preliminary models are different. This means that our average models have multiple disjoint solutions[9]. This in line with the results of the previous Chapter. Recall that implementing the single and the nodal average cost scenarios with and without the preliminary model means change the algorithm starting point. We report a sample of these alternative solutions in the Section 5.7.

In this Section, we present the new formulation of the single and the nodal average cost prices, accounting for investments and the new optimization problem solved by generators. N-EIIs and EIIs maximize their respective surpluses. The formulation of their problems is as in Section 3.4 both for the single and the nodal average cost based contracts. For this reason, we refer to them. A similar reasoning holds also for the modelling of the network constraints as well as for the energy balance of the two market segments. Slight modifications concern the emission constraint.

5.3.1 Single Average Cost Pricing Model

Under this scenario, energy intensive industries buy electricity at the same average cost price in any location. Taking stock of the French experience, we still assume that EIIs constitute a consortium in order to conclude long-term contracts with generators. We assume that this consortium covers the CWE electricity market. Here, we show how the investment assumption changes the equation of the single average cost price and the mathematical formulation of the generators' problem.

Recall that, since industries require a constant amount of electricity over time, variables related to these contracts do not depend on time t. We refer to this model as "ETS_ISAC".

Single Average Cost Price

The single average cost price inv_p^1 is composed of two terms: the average production inv_pprod^1 and the average transmission inv_ptrans^1 costs. In this endogoneous capacity model, the formulation of inv_pprod^1 becomes:

$$
\begin{aligned}
inv\_pprod^1 = {} & \frac{(\sum_{f,i,m}(gpc^1_{f,i,m} \cdot (cost_{f,i,m} + em_m \cdot \lambda) \cdot 8760))}{\sum_i d^1_i \cdot 8760} \\
& + \frac{(\sum_{f,i,m}(gpi^1_{f,i,m} \cdot (fuel_{f,i,m} + em_m \cdot \lambda) \cdot 8760))}{\sum_i d^1_i \cdot 8760} \\
& + \frac{\sum_{f,i,m} FC\_annual_{f,i,m} \cdot G^1_{f,i,m}}{\sum_i d^1_i \cdot 8760}
\end{aligned}
\tag{5.14}
$$

[9] Considering our assumptions and input data.

$$+\frac{\sum_{f,i,m} FC\_annual_{f,i,m} \cdot investment^1_{f,i,m}}{\sum_i d^1_i \cdot 8760}$$

The first term involves the variable fuel ($cost_{f,i,m}$) and emissions ($em_m \cdot \lambda$) costs multiplied by the electricity ($gpc^1_{f,i,m}$) generated for EIIs by running $G^1_{f,i,m}$, namely the part of the existing capacity dedicated to them. The second, instead, introduces the variable fuel ($fuel_{f,i,m}$) and emissions ($em_m \cdot \lambda$) costs of the electricity produced ($gpi^1_{f,i,m}$) by exploiting the EII dedicated part of new power plants ($investment^1_{f,i,m}$). Finally, the two last terms compute the average capacity charges associated with old and new power stations. $FC\_annual_{f,i,m}$ are the exogenous annual fixed costs that we assume identical for old and new power stations[10]. Note that the single (and also the nodal) average cost price is computed on the basis of an accounting scheme. For this reason, the capacity split is by individual units and then the variables used to define it depend on generator f, node i and technology m.

The average transmission cost ($ptrans^1$) is again computed in the following way:

$$inv\_ptrans^1 = \frac{(\sum_{l,i} PTDF_{l,i} \cdot (\sum_f g^1_{f,i} - d^1_i) \cdot 8760 \cdot \sum_t ((\mu^{t,+}_l - \mu^{t,-}_l) \cdot proportion^t))}{\sum_i d^1_i \cdot 8760} \tag{5.15}$$

where $(\sum_f g^1_{f,i} - d^1_i) \cdot 8760$ is the annual nodal injection and $-\mu^{t,+}_l$and $\mu^{t,-}_l$ are the dual variables representing the congestion costs. They account for the two directions that power flows can follow through network lines. The final average price p^1 thus corresponds to:

$$inv\_p^1 = inv\_pprod^1 + inv\_ptrans^1 \tag{5.16}$$

Generators' Optimization Problem

The maximization problem solved by generators adapts the one of the reference case presented in Section 5.2.1 to the average cost contracts. Generators can run either the already existing capacities or the new power plants in order to supply the two market segments. This decision is taken under the prospective to maximize the profits accruing from sales to N-EIIs and satisfying the demand from EIIs at the minimum cost. Parallel to Section 3.4.2, we adopt a Quasi-Variational Inequality (QVI) approach to define the EIIs' pricing system and determine the quantity of electricity $g^1_{f,i}$ sold to them. To this scope, we add the industrial energy balance (5.25) and the transmission constraints (5.26) and (5.27) to the generators' optimization problem. As already said, there are two prices that influence the interaction between generators and energy intensive industries. The first is represented by the average production cost price inv_pprod^1 that generators receive from selling electricity to EIIs while the second is the dual variable β^1 that corresponds to the marginal cost price that industries should pay under a perfectly competitive regime. As already discussed in Chapter 3, this variable β^1 guarantees the efficiency of the capacity allocation between the two market segments. The presence of this two different prices induce us to adopt a quasi-variational inequalities approach that is often used to model cases where a price is not well defined. We recall that under our model assumption, this quasi-variational inequality problem can be assimilated to a variational inequality problem as proved by Harker ([26], Theorem 6). These variational inequalities establish the link between QVI and the optimization problem (5.17)-(5.27) stated below.

[10] Recall that in order to simplify our analysis and the set of input data used, we assume that old and new capacities have identical cost structure. However, our models enable us to consider alternative assumptions.

The optimization problem (5.17)-(5.27) reflects the market segmentation and the capacity splitting assumptions characterizing the average cost models. Both the annual variable (fuel, emission and transmission) and capacity charges (old and new power units) are differentiated between the two market segments. The price $p_i^{t,2}$ multiplied by the quantity of power sold $g_{f,i}^{t,2}$ define the revenues resulting from selling electricity to N-EIIs. Variable $g_{f,i}^{t,2}$ accounts for the power generated by existing plants $gpc_{f,i,m}^{t,2}$ and new stations $gpi_{f,i,m}^{t,2}$. An identical reasoning holds also for the $g_{f,i}^{1}$ related to the EIIs' model. In the objective function (5.17) we account also for the term $\lambda \cdot E_f$ which quantifies the value of the allowance given for free (if any) to generators[11].

Finally, since the variables defining the electricity production and consumption are in hours, we multiply the households' ones by the parameter $hour^t$, stating the duration of the peak and off-peak periods. Industries' variables are instead multiplied by 8760 indicating the number of hours in one year.

$$\mathbf{Max} \ \sum_{t,i} p_i^{t,2} \cdot g_{f,i}^{t,2} \cdot hour^t \tag{5.17}$$

$$- \sum_{i,m} cost_{f,i,m} \cdot gpc_{f,i,m}^{1} \cdot 8760 - \sum_{i,m} fuel_{f,i,m} \cdot gpi_{f,i,m}^{1} \cdot 8760$$

$$- \sum_{t,i,m} cost_{f,i,m} \cdot gpc_{f,i,m}^{t,2} \cdot hour^t - \sum_{t,i,m} fuel_{f,i,m} \cdot gpi_{f,i,m}^{t,2} \cdot hour^t$$

$$+ \lambda \cdot (E_f - \sum_{i,m} gpc_{f,i,m}^{1} \cdot em_m \cdot 8760 - \sum_{i,m} gpi_{f,i,m}^{1} \cdot em_m \cdot 8760$$

$$- \sum_{t,i,m} gpc_{f,i,m}^{t,2} \cdot em_m \cdot hour^t - \sum_{t,i,m} gpi_{f,i,m}^{t,2} \cdot em_m \cdot hour^t)$$

$$- \sum_{i,m} FC\_annual_{f,i,m} \cdot investment_{f,i,m}^{1} - \sum_{i,m} FC\_annual_{f,i,m} \cdot investment_{f,i,m}^{2}$$

subject to:

$$0 \leq g_{f,i}^{1} \leq \sum_{m} gpc_{f,i,m}^{1} + \sum_{m} gpi_{f,i,m}^{1} \quad (\eta_{f,i}^{1}) \qquad \forall \ f, i \tag{5.18}$$

$$0 \leq g_{f,i}^{t,2} \leq \sum_{m} gpc_{f,i,m}^{t,2} + \sum_{m} gpi_{f,i,m}^{t,2} \quad (\eta_{f,i}^{t,2}) \qquad \forall \ t, f, i \tag{5.19}$$

$$0 \leq gpc_{f,i,m}^{1} \leq G_{f,i,m}^{1} \quad (\nu c_{f,i,m}^{1}) \qquad \forall \ f, i, m \tag{5.20}$$

$$0 \leq gpi_{f,i,m}^{1} \leq investment_{f,i,m}^{1} \quad (\nu i_{f,i,m}^{1}) \qquad \forall \ f, i, m \tag{5.21}$$

$$0 \leq gp_{f,i,m}^{t,2} \leq G_{f,i,m}^{2} \quad (\nu c_{f,i,m}^{t,2}) \qquad \forall \ t, f, i, m \tag{5.22}$$

$$0 \leq gpi_{f,i,m}^{t,2} \leq investment_{f,i,m}^{2} \quad (\nu i_{f,i,m}^{t,2}) \qquad \forall \ t, f, i, m \tag{5.23}$$

$$0 \leq G_{f,i,m}^{1} + G_{f,i,m}^{2} \leq G_{f,i,m} \quad (\nu_{f,i,m}) \qquad \forall \ f, i, m \tag{5.24}$$

$$\sum_{f,i} g_{f,i}^{1} - \sum_{i} d_i^{1} = 0 \quad (\beta^1) \tag{5.25}$$

[11] See Section 5.2.1 for more details.

$$(\sum_i PTDF_{l,i} \cdot (\sum_{f,i} g^1_{f,i} + \sum_{f,i} g^{t,2}_{f,i} - d^1_i - d^{t,2}_i)) \leq Linecap_l \quad (\mu^{t,+}_l) \qquad \forall\, t, l \tag{5.26}$$

$$-(\sum_i PTDF_{l,i} \cdot (\sum_{f,i} g^1_{f,i} + \sum_{f,i} g^{t,2}_{f,i} - d^1_i - d^{t,2}_i)) \leq Linecap_l \quad (\mu^{t,-}_l) \qquad \forall\, t, l \tag{5.27}$$

The maximization problem is subject to several constraints which ensure the hourly electricity balance. Power, in fact, is a particular commodity since is not storable.

Inequalities (5.18) and (5.19) define the generation processes for EIIs and N-EIIs . These two constraints are matched with the dual variables $(\eta^1_{f,i})$ and $(\eta^{t,2}_{f,i})$ corresponding to the marginal production charges faced by generator f when they produce at node i.

Conditions (5.20), (5.22), (5.21) and (5.23) represent the capacity constraints . In (5.20) and (5.22), $G^1_{f,i,m}$ and $G^2_{f,i,m}$ correspond to the existing capacity reserved respectively for EIIs and N-EIIs; while $investment^1_{f,i,m}$ and $investment^2_{f,i,m}$ in (5.21) and (5.23) indicate the new power plants built for the two market segments. All these constraints are respectively paired with the dual variables $\nu c^1_{f,i,m}$, $\nu c^{t,2}_{f,i,m}$, $\nu i^1_{f,i,m}$ and $\nu i^{t,2}_{f,i,m}$ which are the marginal capacity values of old and new power stations. Finally, condition (5.24) states that the sum of old power stations that each firm f split between EIIs and N-EIIs must not exceed the existing capacity $G_{f,i,m}$. This constraint is associated with the dual variable $\nu_{f,i,m}$ that implicitly sets the equality between $\nu c^1_{f,i,m}$ and $\nu c^{t,2}_{f,i,m}$; i.e. the marginal values of the old capacities respectively dedicated to EIIs and N-EIIs. We do not impose a global constraint (like (5.24)) on new capacity, since the industrial demand function implicitly determines this limit. All the variables are supposed to be non-negative.

Last, we include also the energy balance for the industrial segment (5.25) and the transmission constraints (5.26) and (5.27). These conditions are essential in the $QVI(F^f, K^f)$ formulation of the problem since they are used to define the set $K^f(x)$ on which the variable $g^1_{f,i}$ depends. Parallel to the approach followed in Section 3.4.2, the optimization problem (5.17)-(5.27) can be stated as a QVI model where the function F is the gradient map deriving from conditions (5.17)-(5.24) and the set $K^f(x)$ is defined as follows for each generators f:

$$K^f = \{g^1_{f,i} | \sum_{f,i} g^1_{f,i} \geq \sum_i d^1_i \quad and$$

$$\sum_i PTDF_{l,i} \cdot \sum_{f,i} g^1_{f,i} \leq Linecap_l + (\sum_i PTDF_{l,i} \cdot (\sum_{f,i} g^{t,2}_{f,i} - d^1_i - d^{t,2}_i))$$

$$\sum_i PTDF_{l,i} \cdot \sum_{f,i} g^1_{f,i} \geq -Linecap_l - (\sum_i PTDF_{l,i} \cdot (\sum_{f,i} g^{t,2}_{f,i} - d^1_i - d^{t,2}_i))\}$$

As in Section 3.4.2, our model allows to state an equality between the solution set of this $QVI(F^f, K^f)$ model and the associated VI problem because our model assumptions satisfy the properties[12] indicated by Theorem 6 of Harker's study ([26]). Recalling the discussion in Chapter 2, a VI problem can be transformed into a complementarity problem (CP) if the definition set is a convex cone. This is our specific case and complementarity conditions (5.28)-(5.44) result from this transformation. Note that the constraints defining K^f are part of the producers' complementarity problem, but we explain their

[12] The idea is that QVI and VI problems have an identical solution set when the dual variables associated with the constraint defining the feasible set are the same for all players, as the marginal price β^1 and the transmission costs $\mu^{t,-}_l$ and $\mu^{t,+}_l$ in our specific case. See also Chapter 2 and Section 3.4.2.

details in the following Section of global constraints. Their complementarity formulation are obtained by combining conditions (3.35), (3.36) and (3.37) with their respective dual variables β^1, $\mu_l^{t,+}$ and $\mu_l^{t,-}$.

Complementarity conditions (5.28), (5.29), (5.30), (5.31), (5.32), (5.33), (5.34) and (5.35) are exactly the duplication of conditions (5.5)-(5.10) in Section 5.2.1. Note that in (5.28), the marginal electricity price of industries is determined by $(\beta^1 + (\sum_{t,l} proportion^t \cdot (-\mu_l^{t,+} + \mu_l^{t,-}))$. This condition is identical to (3.38) in Section 3.4.2. The variable β^1 is a transfer price and still represents the marginal cost price that industries should pay, at the hub, under a competitive regime. It matches the energy balance constraint of the industrial market like in condition (3.58) of Section 3.4.2.

$$0 \leq \eta_{f,i}^1 - \beta^1 - (\sum_{t,l} proportion^t \cdot (-\mu_l^{t,+} + \mu_l^{t,-}) \cdot PTDF_{l,i}) \perp g_{f,i}^1 \geq 0 \qquad \forall\, f, i \tag{5.28}$$

$$0 \leq \eta_{f,i}^{t,2} - p_i^{t,2} \perp g_{f,i}^{t,2} \geq 0 \qquad \forall\, t, f, i \tag{5.29}$$

$$0 \leq cost_{f,i,m} + \lambda \cdot em_m + \nu c_{f,i,m}^1 - \eta_{f,i}^1 \perp gpc_{f,i,m}^1 \geq 0 \qquad \forall\, f, i, m \tag{5.30}$$

$$0 \leq cost_{f,i,m} + \lambda \cdot em_m + \nu c_{f,i,m}^{t,2} - \eta_{f,i}^{t,2} \perp gpc_{f,i,m}^{t,2} \geq 0 \qquad \forall\, t, f, i, m \tag{5.31}$$

$$0 \leq fuel_{f,i,m} + \lambda \cdot em_m + \nu i_{f,i,m}^1 - \eta_{f,i}^1 \perp gpi_{f,i,m}^1 \geq 0 \qquad \forall\, f, i, m \tag{5.32}$$

$$0 \leq fuel_{f,i,m} + \lambda \cdot em_m + \nu i_{f,i,m}^{t,2} - \eta_{f,i}^{t,2} \perp gpi_{f,i,m}^{t,2} \geq 0 \qquad \forall\, t, f, i, m \tag{5.33}$$

$$0 \leq \sum_m gpc_{f,i,m}^1 + \sum_m gpi_{f,i,m}^1 - g_{f,i}^1 \perp \eta_{f,i}^1 \geq 0 \qquad \forall\, f, i \tag{5.34}$$

$$0 \leq \sum_m gpc_{f,i,m}^{t,2} + \sum_m gpi_{f,i,m}^{t,2} - g_{f,i}^{t,2} \perp \eta_{f,i}^{t,2} \geq 0 \qquad \forall\, t, f, i \tag{5.35}$$

Conditions (5.36)-(5.44) regulate the capacity market. The split of the already existing capacities is defined by (5.36), (5.37) and (5.38) and they correspond exactly to (3.44), (3.45) and (3.46) in Section 3.4.2. (5.39) and (5.40) indicate the production capacity limit of the new power stations respectively dedicated to industries and households. The dual variables matched with these five capacity constraints represent the marginal values of the different technologies. They become positive when plants are run at their full capacities. By the means of conditions (5.41) and (5.42), $\nu_{f,i,m}$ implicitly imposes the equality between $vc_{f,i,m}^{t,2}$ and $vc_{f,i,m}^1$ and ensures an efficient allocation of old capacity (as already explained in Section 3.4 for conditions (3.47) and (3.48)) . In contrast, the efficiency of investment undertaken for the two classes of consumers is guaranteed by conditions (5.43) and (5.44). Note that the equality between scarcity rents $\nu i_{f,i,m}^{t,2}$ and $\nu i_{f,i,m}^1$ is determined by the parameter $FC\_hour_{f,i,m}$ representing the hourly fixed costs faced by power company f to build a new plant m in node i. Finally, the perfect competition rules used to allocate capacities between EIIs and N-EIIs lead to an efficient allocation of the sources and does not induce generators to exercise market power or transfer capacities from EIIs to N-EIIs and vice versa.

$$0 \leq G_{f,i,m}^1 - gpc_{f,i,m}^1 \perp \nu c_{f,i,m}^1 \geq 0 \qquad \forall\, f, i, m \tag{5.36}$$

$$0 \leq G_{f,i,m}^2 - gpc_{f,i,m}^{t,2} \perp \nu c_{f,i,m}^{t,2} \geq 0 \qquad \forall\, t, f, i, m \tag{5.37}$$

$$0 \leq G_{f,i,m} - G_{f,i,m}^1 - G_{f,i,m}^2 \perp \nu_{f,i,m} \geq 0 \qquad \forall\, f, i, m \tag{5.38}$$

$$0 \leq investment^1_{f,i,m} - gpi^1_{f,i,m} \perp \nu i^1_{f,i,m} \geq 0 \qquad \forall\ f,i,m \tag{5.39}$$

$$0 \leq investment^2_{f,i,m} - gpi^{t,2}_{f,i,m} \perp \nu i^{t,2}_{f,i,m} \geq 0 \qquad \forall\ t,f,i,m \tag{5.40}$$

$$0 \leq v_{f,i,m} - vc^1_{f,i,m} \perp G^1_{f,i,m} \geq 0 \qquad \forall\ f,i,m \tag{5.41}$$

$$0 \leq v_{f,i,m} - \sum_t vc^{t,2}_{f,i,m} \cdot proportion^t \perp G^2_{f,i,m} \geq 0 \qquad \forall\ f,i,m \tag{5.42}$$

$$0 \leq FC\_hour_{f,i,m} - \nu i^1_{f,i,m} \perp investment^1_{f,i,m} \geq 0 \qquad \forall\ f,i,m \tag{5.43}$$

$$0 \leq FC\_hour_{f,i,m} - \sum_t \nu i^{t,2}_{f,i,m} \cdot proportion^t \perp investment^2_{f,i,m} \geq 0 \qquad \forall\ f,i,m \tag{5.44}$$

Emission Market

We modify the emission constraints in accordance with the split of old and new capacities. The emission cap still amounts to 358 Mio. ton p.a. and the allowance price λ assumes a positive value when the constraint is biding.

$$\begin{aligned}
&(\sum_{f,i,m} em_m \cdot gpc^1_{f,i,m} \cdot 8760 + \sum_{f,i,m} em_m \cdot gpi^1_{f,i,m} \cdot 8760 + \\
&+ \sum_{t,f,i,m} em_m \cdot gpc^{t,2}_{f,i,m} \cdot hour^t + \sum_{t,f,i,m} em_m \cdot gpi^{t,2}_{f,i,m} \cdot hour^t) \leq CAP \quad (\lambda)
\end{aligned} \tag{5.45}$$

The corresponding complementarity condition is as follows:

$$\begin{aligned}
&0 \leq CAP - (\sum_{f,i,m} em_m \cdot gpc^1_{f,i.m} \cdot 8760 + \sum_{f,i,m} em_m \cdot gpi^1_{f,i.m} \cdot 8760 + \\
&\sum_{t,f,i,m} em_m \cdot gpc^{t,2}_{f,i.m} \cdot hour^t + \sum_{t,f,i,m} em_m \cdot gpi^{t,2}_{f,i.m} \cdot hour^t) \perp \lambda \geq 0
\end{aligned} \tag{5.46}$$

5.3.2 Nodal Average Cost Pricing Model

The nodal average cost pricing model under investments ("ETS_INAC" hereafter) is an extension of both the ETS_NAC model presented in Chapter 3 and the ETS_ISAC case presented in Section 5.3.1. Consumers' optimization problem, energy balance of the two market segments and transmission constraints are as described in Section 3.4.3 of Chapter 3. Generators solve a maximization problem almost identical to that in Section 5.3.1. One has to drop the transmission constraints[13] and replace condition (5.25) with the following:

$$\sum_f g^1_{f,i} - d^1_i = 0 \quad (\beta^1_i) \tag{5.47}$$

The QVI formulation of this problem accounts for these changes and it is line with that of the nodal average cost model in Chapter 3. For this reason we present only the new formulation of the nodal average cost price equation:

[13] In the nodal average cost pricing model, energy intensive industries are locally supplied.

$$inv\_p_i^1 = \frac{(\sum_{f,m}(gpc_{f,i,m}^1 \cdot (cost_{f,i,m} + em_m \cdot \lambda) \cdot 8760))}{d_i^1 \cdot 8760} + \tag{5.48}$$

$$\frac{(\sum_{f,m}(gpi_{f,i,m}^1 \cdot (fuel_{f,i,m} + em_m \cdot \lambda) \cdot 8760))}{d_i^1 \cdot 8760} +$$

$$\frac{\sum_{f,m} FC\_annual_{f,m,i} \cdot G_{f,i,m}^1}{d_i^1 \cdot 8760}$$

$$\frac{\sum_{f,m} FC\_annual_{f,m,i} \cdot investment_{f,i,m}^1}{d_i^1 \cdot 8760}$$

By model construction, the average cost price varies over nodes. The prices $inv\_p_i^1$ depend on the variable cost components (fuel ($cost_{f,i,m}$ and $fuel_{f,i,m}$) and emission ($em_m \cdot \lambda$)) and on the annual fixed charges $FC\_annual_{f,i,m}$. Again, the parameter $cost_{f,i,m}$ is multiplied by the variable $gpc_{f,i,m}^1$ espressing the amount of electricity that generators produce running old plants; whereas the parameter $fuel_{f,i,m}$ is used to compute the fuel costs concerning the employment of new power stations. Recall that, in the ETS_INAC pricing system, industries have the advantage that they do not pay congestion costs.

Finally the emission constraint is as condition (5.45).

5.4 Analysis of the Results of the Investment Models

This Section is devoted to the presentation of the results of the investment models. Our objective is twofold since we want to understand whether the EU-ETS may influence investment policy and the role played by long-term contracts in this new scenario.

Note that, by construction, generators must conclude special contracts with industries, but they are not obliged to invest in new capacity. However, two different reasons induce generators to build new power stations. First, they can enlarge their production park and the demand served; second, they can improve their efficiency, reducing carbon emissions[14]. Generators can decide the capacity of their new plants and their location. This decision is affected by the fixed costs of the different technologies. In accordance with our input data, capacity costs vary by technology and location (see Table 2.4). It means that building a plant in one country may cost less than building an identical power station in another country. Because costs do not vary by companies and these can invest anywhere, we are not able to ascertain in these models (in contrast with versions of the models that would include market power) that investments attributed to a company are really those of that company. We then present investments only technology type and location, but not by generator since it does not really matter who invests. This holds not only in the perfectly competitive market described by the reference case, but also in the average cost price models. In fact, in absence of market power, average cost contracts are defined by region and not by company. However, in our models, we express capacities (old and new) and the associated costs with respect to generators f. We introduce this assumption because it make our models suitable for studying other cases where generators can exercise market power.

[14]Recall that we do not model this assumptions and we assume that both old and new capacities have identical price structure.

We follow the progressive approach used in Chapter 4 and we first present the results of the reference model with and without carbon restrictions. This enables to assess the impact of the ETS on electricity prices and consumption (as in Chapter 3); but more important, on investment strategies[15]. We anticipate that EU-ETS drives investments forcing the development of clean technologies. Furthermore, because of the increased capacity availability, EIIs raise their electricity consumption with regard to the cases without investments. Taking stock of this outcome, we implement the average cost models and we analyze how investment decisions affect capacity share and special contracts. Again, we find that the nodal average cost scenario guarantees the highest industrial consumption level under carbon regulation.

5.4.1 European Emission Trading Scheme and Investment Policy. Analysis of the Reference Scenario

In order to investigate the impact of the EU-ETS on investment policy, we implement the reference investment case ETS_IR presented in Section 5.2 with and without emission constraint and then we compare the results attained. In order to simplify our exposition, we denote the reference investment case with unconstrained emissions as "NETS_IR". This model is simply obtained from ETS_IR by dropping its emission constraint and the emission opportunity costs from generators' profit function (5.1). We first present the results concerning investments and technology mix used by generators to produce electricity; we then analyze changes in electricity prices and demand and finally we describe the situation of the emission market.

Investments and technology mix

Tables 5.1 and 5.2 list investments by node and technology before and after the introduction of the EU-ETS. The comparison of the results reported in these two Tables reveals that the ETS influences investment choices and drives them towards clean technologies. This corresponds exactly to the scope of the European environmental policy.

	Nuclear	**Lignite**	**Coal**	**Total**
Germany		18,570		**18,570**
France	17,799			**17,799**
Merchtem			3,078	**3,078**
Gramme				
Krimpen			2,955	**2,955**
Maastricht			1,386	**1,386**
Zwolle				
Total	**17,799**	**18,570**	**7,419**	**43,788**

Table 5.1: Investments in the NETS_IR Scenario in MW

As indicated in Table 5.1, in NETS_IR scenario, generators invest in nuclear in France (17,799 MW), in lignite in Germany (18,570 MW) and in coal in Merchtem, Krimpen and Maastricht (3,078 MW; 2,955 MW and 1,386 MW respectively). Globally, new power stations amount to 43,788 MW and

[15]We recall that nuclear power investments are allowed only in France. A similar reasoning holds also for lignite that can be exploited only in Germany. Finally, hydro is not available in the Netherlands.

all generators contribute to their realization (see Table 5.42 in Appendix 5.9 for a detailed investment list). As argued before, the allocation of these new capacities among power companies as determined by the model should be taken with a solid dose of salt. It is indeed impossible to distinguish in a model without market power which company invests in which capacity if all capacities of a given technology have the same cost.

	Renewable	**Nuclear**	**Total**
France		26,641	**26,641**
Merchtem	2,600		**2,600**
Total	**2,600**	**26,641**	**29,242**

Table 5.2: Investment in the ETS_IR Scenario in MW

Also in the ETS_IR scenario, all companies build new power plants even though they change their investment choices. Parallel to what we observed in Chapter 4, the ETS makes clean technologies more competitive. In fact, the switch from dirty to environmental friendly technologies concerns not only investments, but also already existing capacities. Generators reduce the utilization of lignite/coal power plants in favor of CCGT and clean technologies and replace investments in lignite and coal with new renewable and nuclear power plants, as highlighted by Table 5.2. Investments in nuclear increase by almost 50%: from a level of 17,799 MW in the NETS_IR they raise to 26,641 MW in the ETS_IR (compare Tables 5.1 and 5.2). The new available capacity amounts to 29,942 MW, of which 91% is represented by nuclear and the remaining 9% by renewable. They are located respectively in France and in the Belgian node Merchtem (detailed values are reported in Table 5.43 in Appendix 5.9). Generators choose these two nodes for different reasons. France is the unique country in the model that allows investments in nuclear and this technology completely meets ETS target. Merchtem is one of the nodes where renewable is (according to our data) less expensive in terms of fixed costs. There are no investments in hydro since it is more expensive than renewable[16]. Recall that, in accordance with our input data, in Germany, in France and in Belgium, renewable technologies are less expensive than hydro and this induces generator to prefer investments in the former to the in latter technology (see Table 2.4 in Chapter 2). As expected nuclear capacity in France plays a key role in the market. Both old and new plants are used to cover both local and foreign power demands. In each period, part of the electricity produced in France is exported, since it overcomes local demand. Note that French power production is mainly based on clean sources (hydro, renewable and nuclear) both in summer and in winter as indicated in Tables 5.32 and 5.33 in Appendix 5.9.

Under the NETS_IR scenario, coal and lignite cover the 38% of the summer electricity demand and the rest is supplied by clean sources (namely hydro (6%), renewable (4%) and nuclear (52%)). In winter, the proportion of clean technologies decrease ((hydro (4%), renewable (3%) and nuclear (42%))), while the utilization of coal based technologies increases (43%). Moreover, a small amount of CCGT plants is run (8%). These fuel mixes account both for the new and the old plants.

After the inception of the ETS, the fuel contribution to electricity production changes. In summer, coal accounts only for the 25% of the total electricity production against the 38% in the NETS_IR case. Nuclear provides the 59% of the electricity demanded (vs 52% in the NETS_IR scenario) and also hydro and renewable shares raise up to 7%. Finally, CCGT covers 7% of the total demand. The tendency registered in winter is similar: coal share drops to 27% from 43% level in the NETS_IR,

[16]This depends on our input data. See Table 2.4 in Chapter2.

accompanied by an increasing exploitation of CCGT (14% vs 8% in the NETS_IR model). The same holds for renewable (4% vs 3%), while hydro is fixed to 4%. Note that, in the ETS_IR, the proportions of nuclear and renewable increase because they account also for investments. In contrast, coal and CCGT refer only to old capacities. Investments are able to satisfy respectively the 34% and the 22% of the summer and winter consumers' electricity demand. The remaining proportions are covered by the already existing capacities. Among them, hydro and renewable plants are totally employed, while (existing) coal and CCGT technologies are partially exploited. Finally, old gas and oil-based plants remain idle.

All these results confirm our finding of the ETS_R scenario in Chapter 4. As intended, ETS encourages the exploitation of clean and low emitting technologies. However, the additional costs implied by carbon price negatively affects consumers (N-EIIs and EIIs) even when restructuring investments are possible. This is highlighted by the fact that, with the implementation of the ETS, generators reduce their investments by 33%. This is the illustration of the leakage phenomenon. It results from a straightforward reasoning: carbon regulation increases power prices, consumers lessen their demand of electricity and consequently companies cut their investments. This is what EIIs announce. Note that differently from the ETS_R scenario studied in Chapter 4, two factors with different natures interact in the in the ETS_IR scenario: first, carbon cost has a negative effect; second investments have a positive impact. Both effects compensate each other and the outcome is not trivial. In order to measure the "pure" investment effect, one has to compare the results of the two reference cases ("NETS" and "ETS") with and without investment assumptions[17]. At equilibrium, investments increase the amount of available capacity and this allows consumers to raise their electricity demand. Our results confirm this tendency. Both in summer and in winter, consumers' electricity demands in NETS_IR and ETS_IR cases are higher than in the NETS_R and ETS_R scenarios with fixed capacity (see Chapter 4). In particular, comparing NETS_IR with NETS_R, we see that investments encourage industries to globally raise their hourly electricity demand by 18% (from 68,294 MWh in NETS_R to 80,629 MWh in NETS_IR). A similar reasoning holds also for N-EIIs, even if relative changes are lower: +0.3% in summer and +4% in winter[18]. This positive tendency is confirmed also by the couple ETS_IR and ETS_R. With investments, industries increase their electricity consumption by 11% (from 60,613 MWh in ETS_R to 67,388 MWh in ETS_IR) as well as N-EIIs (+1% and +2% respectively in summer and in winter).

Electricity Prices and Demand

We have already compared the NETS_IR with the ETS_IR in order to assess the impact of the emission policy on investment strategies. We now compare these two cases in order to quantify the ETS effects on electricity prices and demand. Results are not surprising: due to the pass through of carbon price, electricity becomes more expensive and consumers reduce their electricity demand. A cross evaluation can be conducted comparing the relative changes of industrial demand under the ETS and the investment assumptions. The aforementioned 11% increase of electricity demand (due to investments) in the ETS_IR is lower than the 18% (due to investment) in the NETS_IR case: this a direct consequence of the ETS.

[17] We have four different cases: NETS_R, NETS_IR, ETS_R and ETS_IR. The investment impact is determined by the comparison between NETS_R with NETS_IR and ETS_R with ETS_IR. In contrast, the ETS impact (under investment assumptions) is defined by comparing NETS_IR with ETS_IR.

[18] Recall that by construction N-EIIs are less flexible than EIIs.

	NETS_IR	ETS_IR	Variations
Germany	38,481	27,907	-27%
France	27,754	27,754	0%
Merchtem	4,899	4,054	-17%
Gramme	2,362	2,224	-6%
Krimpen	3,604	2,750	-24%
Maastricht	1,231	956	-22%
Zwolle	2,297	1,742	-24%
Total	**80,629**	**67,388**	**-16%**

Table 5.3: EIIs' Electricity Demand in the NETS_IR and the ETS_IR Scenarios in MWh

	NETS_IR		ETS_IR		Variations	
	Summer	**Winter**	**Summer**	**Winter**	**Summer**	**Winter**
Germany	19,942	49,266	18,983	48,253	-5%	-2%
France	22,127	45,866	22,127	45,866	0%	0%
Merchtem	1,334	4,622	1,310	4,526	-2%	-2%
Gramme	586	1,978	587	1,945	-0.2%	-2%
Krimpen	3,004	7,537	2,916	7,359	-3%	-2%
Maastricht	716	1,827	695	1,789	-3%	-2%
Zwolle	1,201	3,060	1,160	2,994	-3%	-2%
Total	**48,910**	**114,155**	**47,777**	**112,731**	**-2%**	**-1%**

Table 5.4: N-EIIs' Summer and Winter Electricity Demand in the NETS_IR and ETS_IR Scenarios in MWh

Table 5.3 shows the nodal relative change in industrial demand. Recall that we assume that EIIs have a constant demand over year. Apart in France where the ETS does not affects EIIs, all other nodes reduce their industrial electricity consumption and, globally, the cut amounts to 16%. Nodal relative changes are in average around -20%, even if in the Belgian node Gramme the cut is lower (-6%). These significant reductions in industrial consumers' demand are explained by the fact that we set their reference elasticity at -1, in order to account for a possible relocation of their facilities. N-EIIs face an identical situation even if their consumption reductions are more limited. These are -2% and -1% respectively in summer and in winter. Again, in France there are no variations (see Table 5.4). The welfare analysis confirms these results: EIIs face a reduction of 28% of their global surplus; whereas the cut for N-EIIs is about 3%.

Table 5.5 lists the nodal prices paid by N-EIIs and EIIs. We recall that, by construction, they do not differ per consumer group and are computed using the marginal cost approach. When emissions are constrained, power companies are induced to change their fuel mix and to run more environmental-friendly plants. In summer, they reduce the exploitation of coal and replace part of it with old CCGT technologies[19]. However, coal is still at the margin at the German hub node and, augmented by its carbon opportunity cost, defines electricity prices[20]. The contribution of the carbon cost components

[19] In the NETS_IR scenario, power companies do not exploit CCGT in summer and prices are set by lignite and coal plants.

[20] In accordance with our input data, the fuel cost of coal plant amounts to 21.62 €/MWh. Its carbon opportunity cost is computed multiplying its emission factor (0.9542 ton/MWh) by the allowance price (19.21 €/ton in this case).

	NETS_IR		ETS_IR		Variations	
	Summer	**Winter**	**Summer**	**Winter**	**Summer**	**Winter**
Germany	19.72	36.47	39.95	44.77	103%	23%
France	4.50	35.66	4.50	35.66	0%	0%
Merchtem	32.63	36.35	39.95	44.74	22%	23%
Gramme	21.62	36.29	20.84	43.03	-3.6%	19%
Krimpen	32.62	36.36	44.65	45.90	37%	26%
Maastricht	32.63	36.35	44.65	44.65	37%	23%
Zwolle	28.93	36.38	43.09	45.12	49%	24%

Table 5.5: EIIs and N-EIIs' Electricity Prices in the NETS_IR and the ETS_IR Scenarios in €/MWh

	NETS_IR	**ETS_IR**	**Variations**
Germany	399,187,815	285,941,251	-28%
France	30,784,252	270,677	-99%
Merchtem	42,665,228	14,717,388	-66%
Gramme	3,478,606	3,385,402	-3%
Krimpen	56,615,485	36,820,295	-35%
Maastricht	14,286,850	6,220,183	-56%
Zwolle	11,596,893	11,596,893	0%
Total	**558,615,130**	**358,952,090**	**-36%**

Table 5.6: Nodal Emission Levels in the NETS_IR and in ETS_IR Scenarios in Ton

explains also the increase of the winter electricity price. In fact, both in the NETS_IR and ETS_IR scenarios, CCGT determines electricity prices since it is the last technology run by generators at the hub. However, in the ETS_IR case, one has to account for the pass though of CCGT carbon cost into the electricity price. According to our input data, the emission opportunity cost of a CCGT plants is 8.30 €/MWh. This added to the fuel cost of a CCGT plant in Germany (36.47 €/MWh, that is also the winter price in NETS_IR (see Table 5.5)) gives 44.77 €/MWh that is the electricity price at the hub in the ETS_IR scenario (see Table 5.5).

Transmission costs make electricity prices different over nodes. In fact, lines connecting France with Germany and Belgium are congested as well as those between Belgium and the Netherlands. This network congestion reflects power exchanges among countries: France delivers electricity to the neighboring countries and the Netherlands buy electricity from the Belgian nodes, which are supplied by France.

Emission Market

We conclude with a brief analysis on the emission market. Table 5.4.1 compares nodal emissions before and after the introduction of the EU-ETS regulation. Recall that, in order to model the long-term, we impose an emission cap of about 359 Mio ton p.a. It represents the CO_2 cap of the power sector studied during the second phase (2008-2012) of the EU-ETS. For this reason, it is lower than that adopted in the analysis of Chapter 4. Moreover, we assume that new power stations do not receive any free

The result of this calculation is 18.33 €/MWh that added to 21.62 €/MWh gives exactly 39.95 €/ton. Note that we have an identical situation also in the ETS_R scenario in Chapter 4.

allowances. Before the introduction of the carbon regulation, emissions globally amount to about 558 Mio ton p.a. that are partially generated (39%) by the new lignite and coal plants. The EU-ETS cuts emissions by 36%. One encounters a decreasing emission tendency in the overall electricity system. Relative changes depend on the fuel mix employed and on the quantity of electricity produced. The highest variation is registered in France, where there is a drop of 99% in emissions. In absence of the EU-ETS regulation, French power companies run coal plants to cover consumers' winter demand (see Tables 5.30 and 5.31 in Appendix 5.9). These plants are no longer exploited when the carbon policy is implemented. French generators prefer adopting clean technologies. Marginal emissions of 270,677 ton are generated by some lignite stations that are still used (see Table 5.32 and 5.33 in Appendix 5.9). Similar reasonings hold also in all other location, except for the Dutch node Zwolle, where the amount of CO_2 emitted does not vary. In fact, in this location there is no technological change before and after the EU-ETS (compare Tables 5.30 and 5.31 with 5.32 and 5.33).

In this investment reference case, we have an emission price of 19.21 €/ton. Again, it is much higher than the price observed in the carbon market at the end of the first compliance phase. But it is lower than the price of the second compliance phase. However, this allowance price explains our investment results and the movement from lignite/coal to CCGT technologies in the utilization of old power stations. Finally, we conclude saying that although the electricity consumption in the ETS_IR case is higher than in ETS_R, the corresponding emission price is lower. The relative variation is -21% (from 24.44 €/ton to 19.21 €/ton). This happens because part of the increased demand is covered by the new clean technologies (renewable and nuclear). These investments allow generators to enlarge their production without damaging the environment.

5.4.2 Long-Term Contracts under Investment Assumptions: Impacts on Energy Intensive Industries and the Rest of the Market

The implementation of long-term contracts requires market segmentation, capacity splitting and price discrimination. In this investment scenario, power companies have to decide not only which plants to use to supply N-EIIs and industries, but also the possible investments for the two market segments. Consequently, single and nodal average cost prices include also the capacity cost of these new capacities reserved for industrial consumers. This represents the difference between long-term contracts with and without investments. The other principles remain unchanged: in the single average cost scenario we still assume that energy intensive industries are represented by a consortium which buys electricity from generators operating in the whole Central Western European market (see Figure 2.1 in Chapter 2). In contrast, the nodal average cost approach restricts industries to be supplied by local power companies. Recall this latter pricing system imposes some constraints on industries since they can not freely choose the electricity supplier. We use "ETS_ISAC" and "ETS_INAC" to denote respectively the single and the nodal average cost models.

Investment Policy under the ETS_ISAC Model

According to the results discussed in Section 5.4.1, the EU-ETS induces generators to invest in clean technologies. In particular, renewable and nuclear are again the sources chosen. Tables 5.7 and 5.8 report investments respectively for EIIs and N-EIIs. These depend on technology and location. Because of its restrictive regulation, the construction of nuclear power plants is allowed only in France. In contrast, our capacity costs influence generators' choice to invest in renewable in Germany and in the Belgian node Merchtem[21]. This holds both for EIIs and N-EIIs (see Tables 5.7 and 5.8).

	Renewable	**Nuclear**	**Total**
Germany	1,726		**1,726**
France		12,365	**12,365**
Merchtem	3,309		**3,309**
Total	**5,035**	**12,365**	**17,400**

Table 5.7: Investment for EIIs in the ETS_ISAC Scenario in MW

	Renewable	**Nuclear**	**Total**
Germany	1,887		**1,887**
France		6,106	**6,106**
Merchtem	**803**		**803**
Total	**2,690**	**6,106**	**8,796**

Table 5.8: Investment for N-EIIs in the ETS_ISAC Scenario in MW

All generators invest[22], but the relevant result is that the total investment level amounts to 26,195 MW[23] In sum, nuclear investments equal 18,470 MW, of which 12,365 MW (67%) is devoted to industries (see Table 5.7).

Impacts of the ETS_ISAC Model on EIIs

Thanks to its nuclear endowment, France exports a huge amount of electricity in the industrial market segment. In accordance with our results, France totally produce 32,076 MWh of electricity to supply industries. It includes power generated both by old and nuclear stations. French industries require only 20,091 MW per hour (63% of total production). It means that, each hour, France export around 11,985 MW of its electricity. Moreover, it is the unique node where power production overcomes industrial local need.

This implies that French EIIs have to share their (old and new) clean capacities with foreign industries. This helps generators to meet the market energy balance, but negatively affects French industries, because their electricity price becomes higher than the average (weighted by period duration) of their marginal prices in the ETS_IR scenario. This explains the 27% cut of their electricity consumption. Also in the Belgian node Gramme, the ETS_ISAC scenario has a negative impact on industries which reduce their power demand by almost 10%. Contrarily, in the other nodes, single average cost based contracts accommodate industries which increase their energy demand[24]. These results are perfectly in line with those of ETS_SAC model in Chapter 4 and we can use identical

[21]Generators invest in Merchtem also for "balance" the situation between the two Belgian nodes. We has seen in Chapter 4 that electricity prices and demand in Gramme and in Merchtem have opposite trend. In Gramme, EIIs are damaged when a single average cost price is applied and then prefer contracting electricity at a nodal average cost. In Merchtem, they face a reverse situation. This results from the application of the average cost pricing system and investments mitigate this discrepancy.

[22]For detailed information see Tables 5.44 and 5.45 in Appendix 5.9.

[23]The new power plants dedicated to EIIs are 17,400 MW; while those for N-EIIs are 8,796 MW. Note that globally, investments are 10% lower than in the ETS_IR scenario.

[24]Electricity demand increases are as follows: 15% in Germany and in Merchtem, 25% in Krimpen, 23% in Maastricht and finally 21% in Zwolle.

	NETS_IR	ETS_IR	ETS_ISAC	ETS_INAC
Germany	38,481	27,907	32,159	28,875
France	27,754	27,754	20,091	29,002
Merchtem	4,899	4,054	4,670	5,040
Gramme	2,362	2,224	2,007	2,635
Krimpen	3,604	2,750	3,435	2,473
Maastricht	1,231	956	1,173	561
Zwolle	2,297	1,742	2,105	1,173
Total	**80,629**	**67,388**	**65,641**	**69,758**

Table 5.9: EIIs' Hourly Electricity Demand under Different Investment Scenarios on MWh

Cost components	
Fuel	7.49
Transmission	5.28
Emission	5.68
Fixed costs	18.17
Average cost price	**36.62**

Table 5.10: Single Average Cost Price Components in the ETS_ISAC Scenario in €/MWh

reasonings to explain them. Germany bases its electricity production on lignite and coal plants; in the Netherlands, electricity is mainly provided by CCGT and, finally, the Belgian fuel mix is composed of nuclear, coal and CCGT plants. CCGT and coal power stations are comparatively more costly in terms of variable (fuel and emissions) costs than nuclear or clean technologies. The single average cost price in this investment scenario is 36.62 €/MWh (see Table 5.10). Comparing it with the weighted (by period duration) average of the reference marginal prices in ETS_IR, one can see that price relative changes are aligned with the nodal industrial demand trend. In particular, in France relative price[25] increase of 111% implies a power consumption cut of 27%. The similar tendency occurs in Gramme, where the weighted average of reference marginal price amounts to 30.02 €/MWh. In all other nodes, the average reference price is higher than the single average cost price[26]. However, all together these positive effects do not compensate for the high negative demand variations registered in France and in Gramme. This results in a global cut of industrial electricity demand of about 2.6% (see Table 5.9 for the detailed values) with respect to their ETS_IR consumption level[27]. Taking stock of this result, one may say that the application of the ETS_ISAC policy does not mitigate the whole industrial sector. However, this negative outcome is mainly driven by the cut of French industries which is subject to the effects of the nuclear policy.

[25]The value of the weighted average of the French winter and summer reference price is 17.39 €/MWh that we compare with 36.62 €/MWh.

[26]We recall that in the ETS_IR coal and CCGT technologies, increased by their carbon cost set prices in summer and in winter.

[27]The drop computed with respect to the NETS_IR amounts to 19%.

Summer				
	NETS_IR	**ETS_IR**	**ETS_ISAC**	**ETS_INAC**
Germany	19,942	18,983	18,729	18,980
France	22,127	22,127	22,127	22,127
Merchtem	1,334	1,310	1,316	1,310
Gramme	586	587	588	574
Krimpen	3,004	2,916	2,898	2,916
Maastricht	716	695	691	705
Zwolle	1,201	1,160	1,151	1,165
Total	**48,910**	**47,777**	**47,498**	**47,777**

Table 5.11: N-EIIs' Summer Electricity Demand under Different Investment Scenarios in MWh

Impacts of the ETS_ISAC Model on N-EIIs

The application of the ETS_ISAC method also has a negative effect on N-EIIs. With respect to the ETS_IR scenario, they globally reduce their power consumption by 0.6% (summer) and 0.7% (winter). These price variations depend only on allowance prices[28], since in both scenarios, coal and CCGT set N-EIIs' marginal prices in summer and in winter.

Besides this general negative impact, French N-EIIs' demand remains unchanged in comparison with their ETS_IR level. This holds in both periods (see Tables 5.11 and 5.12). Moreover, the decrease of 4% and 2% of summer power prices in Merchtem and in Gramme induce N-EIIs in those locations to slightly increase their summer electricity demand respectively by 0.4% and 0.1%. Recall that N-EIIs' prices are still defined by the marginal cost approach. Like in the ETS_IR case, coal and CCGT plant fix N-EIIs' electricity prices respectively in summer and in winter.

General Considerations on the ETS_ISAC Model

The comparison between the scenarios ETS_ISAC and ETS_IR shows that the introduction of the single average cost in the investment scenario leads to a global negative impact on consumers. Both EIIs and N-EIIs decrease their electricity demand as a reaction to the increased electricity prices. This also explains the 10% reduction of the global investment level with respect to ETS_IR level. There is also a 29% increase of the allowance price that results from the combination of two factors: the reduced availability of clean technologies, caused by the cut in investments, and the increased exploitation of coal and CCGT. Comparing the results reported in Tables 5.32 and 5.33 with 5.34, 5.35 and 5.36 in Appendix 5.9, one can see that hydro, renewable and nuclear plants are fully run to cover EIIs and N-EIIs both in the ETS_IR and in the ETS_ISAC cases. Moreover, the exploitation of old lignite/coal technologies is almost identical in both scenarios. However, the utilization of old CCGT power stations in the ETS_ISAC is higher. This makes emission constraint tighter and contributes to the rise of allowance price. Again, the carbon cost found is quite high compared to the value observed at the end of the first compliance phase. But it is in line with the price observed in the second compliance phase even though fuel prices have dramatically changed. J. Reinaud in her study on investments in the power sector ([44] pagg. 9-10) estimates that "*Carbon emission prices would need to reach approximately € 26 per tonne of CO_2 for nuclear to be as competitive as CCGT*". These forecasts,

[28]Note that the allowance price in the ETS_ISAC case costs 24.80 €/ton against the 19.21 €/ton in the ETS_IR.

Winter				
	NETS_IR	**ETS_IR**	**ETS_ISAC**	**ETS_INAC**
Germany	49,266	48,253	47,958	48,250
France	45,866	45,866	45,866	45,866
Merchtem	4,622	4,526	4,499	4,527
Gramme	1,978	1,945	1,934	1,937
Krimpen	7,537	7,359	7,032	7,373
Maastricht	1,827	1,789	1,751	1,789
Zwolle	3,060	2,994	2,915	2,997
Total	**114,155**	**112,731**	**111,955**	**112,738**

Table 5.12: N-EIIs' Winter Electricity Demand under Different Investment Scenarios in MWh

which refer to the 2005 period (as our data) support our results since we find that at an allowance price of 24.80 €/ton, power companies construct nuclear instead of CCGT power plants.

Impacts of the ETS_INAC Model on EIIs

The EIIs' situation improves when a nodal average cost pricing system is introduced. Recall that, in this scenario, we assume that industries are supplied by local generators with the advantage that they do not pay transmission costs. The comparison of industrial demand in Table 5.9 points out that the ETS_INAC allows EIIs to increase their global electricity consumption by 4% and 6% with respect to the ETS_IR and ETS_ISAC levels. However, the impact of the nodal average cost policy varies locally. As already observed in Chapter 4, French and Belgian industries always (see Table 5.9) benefit from the application of nodal average cost based contracts[29]. This is also evident from the fact that the electricity consumption level of French and Belgian industries is even higher than in the NETS_IR (see Table 5.9). In contrast, Dutch industries face a reverse situation: electricity becomes so expensive under the ETS_INAC scenario that their power consumption is even lower than in the ETS_IR case. Between the two average cost pricing system, German industries may prefer the single one. These results depends both on investment strategies and on the share of the old capacities. Tables 5.13 and 5.14 provide information on investments in the ETS_INAC model. Investment policy in the ETS_INAC is completely different from that adopted in the single average cost scenario. In particular, generators reserve 29,533 MW of new capacity for N-EIIs of which 1,620 MW are renewable plants in Merchtem and 27,913 MW are nuclear power stations in France (see Table 5.14). In contrast, investment for EIIs amounts only to 2,458 MW. These are new renewable plants built in Merchtem (see Table 5.13). In sum, investments are higher than in the ETS_IR (+9%) and in the ETS_ISAC (+22%) scenarios and amount to 31,992 MW. This represents a first signal that the ETS_INAC globally performs better than the other ETS models. It combines both the restructuring of the infrastructure towards carbon free technologies while mitigating the leakage effect (or at least what we model as leakage). One shall also note that, the allocation of new power stations between consumer groups changes. The N-EII group receives 92% of the new capacity, while only 8% is reserved for EIIs. Because new and old capacities have the same cost characteristic, what matters through is the comparison of the generation system allocated to both groups that is including existing capacities and new capacities. In the single average

[29]Relative changes computed with respect to ETS_INAC are quite significant: +4% (in France), +3% (in Merchtem) and +12% (in Gramme).

cost pricing model, one faces a reverse situation (66% to industries and 34% to N-EIIs).

	Merchtem
Renewable	2,458

Table 5.13: Investments for EIIs in the ETS_INAC Scenario in MW

	France	Merchtem	Total
Renewable		1,620	**1,620**
Nuclear	27,913		**27,913**
Total	**27,913**	**1,620**	**29,533**

Table 5.14: Investments for N-EIIs in the ETS_INAC Scenario in MW

These results directly depend on the assumptions of the average cost pricing different model. In the ETS_INAC, industries can be supplied only by local plants. This holds both for old and new technologies. In terms of investments, it means that the additional electricity generated by new plants can be sold only to industries in the node. Considering our results, 2,458 MW of new renewable plants are built in Merchtem and contribute to restor a more reasonable price for EIIs that in the case without investments (see Chapter 4).

Apart from the small quantity of renewable electricity generated by new stations in Merchtem, industries are mainly supplied by already existing capacity. We already observed, that French and Belgian industries profit from the application of the nodal average cost price system. This depends on the fact that in these nodes the split of old capacities is particularly favorable for local EIIs. In France, generators dedicate 29,002 MW of the existing nuclear capacity to industrial consumers. This amount equals their hourly electricity consumption. Note that generators adopt this strategy also in the ETS_NAC case without investment. They dedicate an identical amount of old nuclear capacity to industries. Consequently, EIIs have equal power demand and price under the ETS_NAC and ETS_INAC scenarios. Nuclear defines nodal average cost price of French EIIs, since it is the sole technology that power companies reserve to them.

	Fuel	Emission	Fixed	Average cost price
Germany	10.55	11.27	19.23	**41.05**
France	4.50	0.00	12.89	**17.39**
Merchtem	4.17	2.00	27.01	**33.18**
Gramme	7.02	2.76	13.28	**23.06**
Krimpen	24.47	12.21	12.10	**48.78**
Maastricht	29.79	6.82	22.66	**59.27**
Zwolle	27.16	11.74	16.94	**55.83**

Table 5.15: Nodal Average Cost Price Components in the ETS_INAC Scenario in €/MWh

Table 5.15 reports the nodal average cost price in details. In France, it amounts to 17.39 €/MWh of which 4.50 €/MWh is the fuel and 12.89 €/MWh is the hourly fixed capacity costs a nuclear plant (see Tables 2.3 and 2.4 in Chapter 2). In Merchtem, industries face a price of 33.18 €/MWh. It is higher than in France because of the different cost contributions of the plants used to supply them.

The new renewable capacities are totally exploited and, in addition, generators run a small proportion of old coal plants. Note that the comparatively higher fixed costs are due to renewable (see Table 2.4 in Chapter 2), while emission charges come from coal. Note also that the nodal price in Merchtem is now 33.18 €/MWh, a much more reasonable figure than the 59.79 €/MWh observed when investments were not allowed. In Gramme, the fuel mix is composed of hydro, renewable, nuclear and CCGT. However, nuclear has the largest share and influence nodal average price with the result that the price to EIIs does not change much at that node. Finally, in Germany and in the Netherlands, average cost prices are quite high. This still depends on the technologies available in those nodes. In all Dutch nodes, renewable, coal and CCGT determine industrial average prices. Recall that CCGT has high fuel costs and low fixed charges: this is reflected in their nodal average cost prices. In Germany, coal technologies cover more than 50% of the industrial electricity need. Other power plants, like hydro, renewable, nuclear and lignite are run. The different cost structure of these technologies explains the quite high emission and capacity charges.

Needless to say, the variety of nodal prices can potentially create distortions of competition since nodal investments differ. We observe (but do not explain) that investments and capacity allocation mitigate that distortion of competition.

Impacts of the ETS_INAC Model on the N-EIIs

As already argued, generators invest for N-EIIs and supply industries by exploiting already existing capacities. In fact, the new capacity dedicated to industries represents only a small proportion of the total investments. Generators prefer to invest for N-EIIs because the electricity produced by these new plants is consumed by the entire N-EIIs' market, independently of their locations. As a consequence, one can construct 27,913 MW of new nuclear capacity in France for N-EIIs[30] and 1,620 MW of renewable in the Belgian node Merchtem (see Table 5.14). These new technologies cover a high proportion of N-EIIs' demand especially in summer (see Table 5.38 in Appendix 5.9) and allow generators to reserve almost all old base-load capacities to industries (see Table 5.41 in Appendix 5.9). This policy enables both N-EIIs and EIIs to take advantage of the application of the nodal average cost pricing system[31].

Generators run both existing and new plants in order to cover N-EIIs' periodical demand. Note that, in addition to new power plants, they exploit the old capacities located in Germany, France, Merchtem and Krimpen to cover N-EIIs' summer demand. In the other locations, electricity is not produced for N-EIIs and they are supplied only by imported power. Considering both the old and the new power stations, generators' technology mix includes 61% of nuclear, 15% of hydro, 4% of renewable, 6% of lignite and 14% of coal. Nuclear and renewable are mainly represented by new stations; hydro, lignite and coal are already existing plants. The two nodes where power companies invests play an important role in the market since they export electricity. This especially holds in France where (old and new) nuclear provides 77% of the electricity generated at the node and it covers the 92% of the power exported. Due to the significant investment, the available capacity in summer is so high that only a small proportion of old nuclear plant is run to supply N-EIIs. Even the new

[30] For our study, this is not relevant who invests. What really matters is final effect, i.e. a significant investment of nuclear in France. Moreover, the electricity produced by these new plants is available for all N-EIIs.

[31] In summer, N-EIIs' consumption level is as in the reference case ETS_IR; in winter it increases by 0.01% and 0.7% respectively with regard to the ETS_IR and the ETS_ISAC scenarios. As already said, industries globally increase their demand.

nuclear technologies are not totally exploited[32].

In winter, electricity is generated in all nodes and France is still the main exporter. In this scenario, all clean and base-load technologies (old and new) are fully run (included nuclear) in order to cover N-EIIs' demand. Coal and CCGT are only partially used.

Comparison of the Allowance Prices under Different Investment Scenarios

The allowance price associated with the ETS_INAC is 19.26 €/ton that is almost identical to that of the reference case ETS_IR (19.21 €/ton). Table 5.16 may help to understand the evolution of allowance prices under investments. They amount to 19.21 €/ton, 24.80 €/ton and 19.26 €/ton respectively in the ETS_IR, ETS_ISAC and the ETS_INAC models. Among these three scenarios, the ETS_INAC allows the highest electricity consumption[33] as indicated in Table 5.16. This scenario is also characterized by the highest investment level (+9% and +22% with respect to the ETS_IR and the ETS_ISAC). It implies that a significant proportion of this demand increase is coved by investments in clean technologies which allow to maintain a quite low allowance price. In the single average cost price model, one faces an opposite situation. Consumers' electricity demand is the lowest among the three ETS scenarios, but its allowance price is the most expensive. This depends on the fact that in the ETS_ISAC investments are comparatively low (-9% and -18% with respect to the ETS_IR and ETS_INAC) and this force power companies to exploit more old capacities including also dirty power plants. Consequently, even though the electricity globally required is lower, emissions are higher and this raises carbon cost.

	N-EIIs			EIIs	Total
	Summer	**Winter**	**Total**		
NETS_R	251	414	*665*	*706*	**1,371**
ETS_R	245	409	*654*	*590*	**1,244**
ETS_SAC	244	406	*650*	*575*	**1,225**
ETS_NAC	245	409	*654*	*611*	**1,265**

Table 5.16: Annual Electricity Demand under Different Investment Scenarios in TWh (EIIs' elasticity -1)

5.5 Welfare Analysis

We propose a welfare analysis in order to give a global view of the effects described in the previous Sections. Compared to the formulation represented in Chapter 4, the social welfare functions include also investment costs. Equations (5.49) and (5.53) define the social welfare respectively in the reference investment and in the single average cost models. These result from the sum of the profit and surplus equations of the four groups of agents operating in the market (namely EIIs, N-EIIs, generators and the TSO). Note that single and nodal average cost contracts have identical welfare function (5.53), but one has to replace the single average cost with the nodal average prices in the agents' surplus and profit conditions. Moreover, in the nodal average cost price, the TSO's profits are not affected by

[32] However, nuclear capacity is totally employed in winter.

[33] Relative changes are +2% and +3% with regard to the ETS_IR and the ETS_ISAC models respectively.

EIIs since they buy electricity from local producers. Moreover, in term of social welfare the emission trading has no effects since the revenues of the allowance sellers are compensated by the costs of the allowance buyers.

Last, we propose the outcome of the welfare analysis obtained by setting EIIs' elasticity at -0.8. We introduce this modification in order to test the robustness of our investment models.

Welfare in the ETS_IR Model

$$\begin{aligned} welfare = & \sum_{t,i}(a_i^{t,1} \cdot d_i^{t,1} \cdot hour^t - \frac{1}{2} \cdot b_i^{t,1} \cdot (d_i^{t,1})^2 \cdot hour^t) \\ & + \sum_{t,i}(a_i^{t,2} \cdot d_i^{t,2} \cdot hour^t - \frac{1}{2} \cdot b_i^{t,2} \cdot (d_i^{t,2})^2 \cdot hour^t) \\ & - \sum_{t,f,i,m} cost_{f,i,m} \cdot gp_{f,i,m}^t \cdot hour^t - \sum_{f,i,m} FC\_annual_{f,i,m} \cdot investment_{f,i,m} \end{aligned} \tag{5.49}$$

- **EIIs' Surplus (ETS_IR)**

$$EIIs' surplus = \sum_{t,i}(a_i^{t,1} \cdot d_i^{t,1} \cdot hour^t - \frac{1}{2} \cdot b_i^{t,1} \cdot (d_i^{t,1})^2 \cdot hour^t) - \sum_{t,i} p_i^t \cdot d_i^{t,1} \cdot hour^t \tag{5.50}$$

- **N-EIIs' Surplus (ETS_IR)**

$$NEIIs' surplus = \sum_{t,i}(a_i^{t,2} \cdot d_i^{t,2} \cdot hour^t - \frac{1}{2} \cdot b_i^{t,2} \cdot (d_i^{t,2})^2 \cdot hour^t) - \sum_{t,i} p_i^t \cdot d_i^{t,2} \cdot hour^t \tag{5.51}$$

Generators' profits are as in condition (5.1) of Section 5.2.1 and we refer to them. In our analysis, we do explicitly model the TSO's problem, even though it operates in the market by regulating the power flows through the network. For this reason, we account for its merchandising profits that it maximizes by selling injection and buying withdrawal services. These are indicated in condition (5.52) .

- **TSO's profit (ETS_IR)**

$$TSO's\ profit = \sum_{t,i}(d_i^{t,1} + d_i^{t,2} - \sum_f g_{f,i}^t) \cdot p_i^t \cdot hour^t \tag{5.52}$$

Equation (5.53) represents the welfare of a market where a single average cost pricing system is applied to energy intensive industries.

Under the single average cost price assumption, EIIs' surplus becomes as in condition (5.54), while the N-EIIs' one remains as in (5.51). Generators' total profits account for the different prices applied to the two consumer groups and for the market segmentation. They are reported in equation (5.55). Finally, the TSO's merchandising profits are as indicated in (5.56).

Welfare in the ETS_ISAC and ETS_INAC Models

$$\begin{aligned} welfare \;&=\; \sum_i (a_i^1 \cdot d_i^1 \cdot 8760 - \frac{1}{2} \cdot b_i^1 \cdot (d_i^1)^2 \cdot 8760) \\ &+ \sum_{t,i} (a_i^{t,2} \cdot d_i^{t,2} \cdot hour^t - \frac{1}{2} \cdot b_i^{t,2} \cdot (d_i^{t,2})^2 \cdot hour^t) \\ &- \sum_{f,i,m} cost_{f,i,m} \cdot gp_{f,i,m}^1 \cdot 8760 - \sum_{t,f,i,m} cost_{f,i,m} \cdot gp_{f,i,m}^{t,2} \cdot hour^t \\ &- \sum_{f,i,m} FC\_annual_{f,i,m} \cdot investment_{f,i,m}^1 - \sum_{f,i,m} FC\_annual_{f,i,m} \cdot investment_{f,i,m}^2 \end{aligned} \tag{5.53}$$

- **EIIs' Surplus (ETS_ISAC)**

$$EIIs'surplus = \sum_i (a_i^1 \cdot d_i^1 \cdot 8760 - \frac{1}{2} \cdot b_i^1 \cdot (d_i^1)^2 \cdot 8760) - \sum_i inv\_p^1 \cdot d_i^1 \cdot 8760 \tag{5.54}$$

- **Generators' Profit (ETS_ISAC)**

$$\begin{aligned} Generators'\ profits =& \sum_i inv\_pprod^1 \cdot d_i^1 \cdot 8760 + \sum_{t,f,i} p_i^{t,2} \cdot g_{f,i}^{t,2} \cdot hour^t \\ &- \sum_{f,i,m} cost_{f,i,m} \cdot gpc_{f,i,m}^1 \cdot 8760 - \sum_{f,i,m} fuel_{f,i,m} \cdot gpi_{f,i,m}^1 \cdot 8760 \\ &- \sum_{t,f,i,m} cost_{f,i,m} \cdot gpc_{f,i,m}^{t,2} \cdot hour^t - \sum_{t,f,i,m} fuel_{f,i,m} \cdot gpi_{f,i,m}^{t,2} \cdot hour^t \\ &+\lambda \cdot (\sum_f E_f - \sum_{f,i,m} gpc_{f,i,m}^1 \cdot em_m \cdot 8760 - \sum_{f,i,m} gpi_{f,i,m}^1 \cdot em_m \cdot 8760 \\ &- \sum_{t,f,i,m} gpc_{f,i,m}^{t,2} \cdot em_m \cdot hour^t - \sum_{t,f,i,m} gpi_{f,i,m}^{t,2} \cdot em_m \cdot hour^t) \\ &- \sum_{f,i,m} FC\_annual_{f,i,m} \cdot investment_{f,i,m}^1 - \sum_{f,i,m} FC\_annual_{f,i,m} \cdot investment_{f,i,m}^2 \end{aligned} \tag{5.55}$$

- **TSO's profit (ETS_ISAC)**

$$TSO's\ profit = \sum_{t,i} (d_i^{t,2} - \sum_f g_{f,i}^{t,2}) \cdot p_i^{t,2} \cdot hour^t + \sum_i ptrans^1 \cdot d_i^1 \cdot 8760 \tag{5.56}$$

Table 5.17 presents the results of the welfare analysis conducted by assuming an industrial demand elasticity of -1. They are in line with the phenomena described in this Chapter. First, investments increase the social benefit as the comparison between 5.17 and Tables 4.11 in Chapter 4 confirms. This holds in all cases studied. A more detailed analysis highlights that the ETS_INAC gives a global welfare (171.58 Billion €) that is almost identical to that of the ETS_IR (171.72 Billion €) and corresponds exactly to the social welfare in ETS_R case (compare values in Table 4.11). This means that under investment assumptions, the nodal average cost pricing system has a good performance and may possibly mitigate the leakage impact of the EU-ETS. Note that N-EIIs' surplus in ETS_INAC scenario is slightly higher than in the ETS_IR model. This results is not surprising at all. We recall that, thanks to the investment and capacity splitting policies adopted by generators in the ETS_INAC case, the N-EIIs' demand in summer is identical in the two scenarios (see Table 5.11); in winter the ETS_INAC allows N-EIIs to consume 0.01% more than in the ETS_IR model (see Table 5.12).

Billion €	**NETS_IR**	**ETS_IR**	**ETS_ISAC**	**ETS_INAC**
EIIs	20.18	14.68	12.47	15.08
N-EIIs	136.97	132.55	130.89	132.56
Consumers	**157.15**	**147.23**	**143.36**	**147.65**
Generators	**15.79**	**23.51**	**26.09**	**22.95**
Allowances		*6.90*	*8.90*	*6.91*
TSO	**0.52**	**0.99**	**1.21**	**0.98**
Welfare	**173.46**	**171.72**	**170.66**	**171.58**

Table 5.17: Welfare under Different Investment Scenarios (EIIs' Elasticity -1)

EIIs' surplus in the ETS_INAC case is also 3% higher than in the ETS_IR scenario. We already observed that the ETS_INAC models allows EIIs in France and in Belgium to increase their consumption[34]. The increases of EIIs' demand in these nodes are so high that recover the demand reductions (with respect to the ETS_IR) in the remaining locations. These significant demand increases have also another interpretation.

Billion €	**NETS_IR**	**ETS_IR**	**ETS_ISAC**	**ETS_INAC**
EIIs	22.55	17.10	15.03	17.02
N-EIIs	137.00	132.53	130.89	132.57
Consumers	**159.55**	**149.63**	**145.92**	**149.59**
Generators	**15.74**	**23.54**	**26.18**	**23.47**
Allowances		*6.91*	*8.90*	*6.91*
TSO	**0.54**	**0.99**	**1.21**	**0.98**
Welfare	**175.83**	**174.16**	**173.31**	**174.04**

Table 5.18: Welfare under Different Investment Scenarios (EIIs' Elasticity -0.8)

The situation is different under the ETS_ISAC case. According to our results (see Table 5.9), industries globally reduce their electricity demand by 3% with respect to the ETS_IR. This leads

[34]In France, industries are only supplied by old nuclear capacity. We recall that French generators dedicated to local EIIs 29,002 MW of already existing nuclear capacity. These cover the whole demand of French EIIs. Consequently, their nodal average cost price is quite low because determined by nuclear plants. In Merchtem industrial demand is mainly covered by new renewable plants and, finally, in Gramme only existing capacities are reserved for EIIs and the mix includes hydro, renewable, nuclear (84%) and a small proportion of coal.

to a consequent decrease of 15% of their surplus. As already discussed, the cut of EIIs' demand is mainly due to the fall of the French (-28%) and Belgian (-10% in Gramme) industrial consumption. In the other locations, energy intensive industries behave in an opposite way by increasing their power demand. In contrast, N-EIIs are negatively affected both by the EU-ETS burdens and the application of single average cost pricing system.

Generators benefit from the implementation of the EU-ETS in all scenarios. In Table 5.17, we report the generators' profits (line "Generators") that we compute by assuming that they receive for free the entire amount of allowances needed. This corresponds to a case of full grandfathering and leads to windfall profits. The comparison with the NETS_IR case shows that generators increase their profits by 49%, 65% and 45% respectively in the ETS_IR, ETS_ISAC and in the ETS_INAC models. In addition, we report separately the allowance costs (line "Allowances") that are determined by the product of the allowance prices in the different scenarios and the emission cap. The generators' profits under the hypothesis of full auctioning are simply obtained by subtracting the allowance values from the corresponding profit reported at line "Generators". Note, that also considering this assumption, generators' profits are higher than in the NETS_IR cases. This phenomenon is explained by the general augment of the electricity prices (at least those paid by N-EIIs) caused by the EU-ETS. All the intermediate combination between auctioning and grandfathering are possible. Note that this approach allows us to study the impact of different allocation methods on generators' profits.

Table 5.18 reports the welfare results obtained by assuming a price elasticity of EIIs fixed at -0.8 at the reference point. Values are different, but the comparison between Tables 5.17 and 5.18 reveals an identical evolution of the social welfare among the four scenarios studied. These results are also supported by the levels of the global electricity demand (see Tables 5.16 and 5.19). In all scenarios, N-EIIs have almost an identical annual demand. Again, industries achieve their highest consumption level in the ETS_INAC case. Comparing the results obtained under these two EIIs' elasticity assumptions, we notice that generators change the methodology used to allocate old and new capacities between consumer groups. For instance in the nodal average cost case with elasticity -1, generators reserve new installations to N-EIIs and exploit existing power plants to supply industries. In nodal average cost case with elasticity set at -0.8, we register an opposite situation. A similar reasoning holds also for the single average cost models with elasticity -1 and -0.8. This strange behaviours are explained by the non-convexity characterizing the average cost models. Nevertheless, the final outcome in terms of welfare remains unchanged.

	N-EIIs			**EIIs**	**Total**
	Summer	**Winter**	**Total**		
NETS_IR	251	414	*665*	*672*	**1,338**
ETS_IR	245	409	*654*	*578*	**1,232**
ETS_ISAC	244	406	*650*	*565*	**1,215**
ETS_INAC	245	409	*654*	*587*	**1,241**

Table 5.19: Annual Electricity Demand under Different Investment Scenarios in TWh (EIIs' elasticity -0.8)

5.6 Sensitivity Analysis

This Section describes the results of a sensitivity analysis. Parallel to the approach adopted in Section 4.5 in Chapter 4, we simplify the structure of our investment models by assuming that the allowance price is exogenously determined. As already explained, we change the point of view of our analysis by setting the carbon cost and evaluating the impacts of the application of this alternative approach on investments, emissions, electricity prices and consumption. For the sake of consistency, we consider again the scenarios investigated in Section 4.5. Recall they are:

- Allowance price is equal to 20 €/ton ("AP20" hereafter);
- Allowance price is equal to 70 €/ton ("AP70" hereafter)

The results of the AP20 scenario are in line with the those of the investment models previously described, since 20 €/ton corresponds to the average of the allowances price we endogenously found. Recall that we test the case of the allowance price set at 70 €/ton since it is the carbon cost that the European Commission is reputed to target to induce development in clean technologies. Taking stock of this, our objective here is to understand the extent to which a high carbon cost boosts investments in the right direction, i.e. towards renewable sources. As already discussed in the previous Sections, an allowance price of around 20 €/MWh induces power companies to abandon dirty technologies. For this reason, under the assumption of 70 €/ton, we expect an improvement of this phenomenon. Additionally, we want to analyze the role played by long-term contracts in this new context.

We recall that nuclear power investments are allowed only in France and it is not possible to exploit hydro power in the Netherlands.

Reference Model with Endogenous Allowance Price

In the absence of any environmental policy, power companies totally build 43,788 MW of new capacities represented by nuclear (in France), lignite (in Germany) and coal (in Merchtem, Krimpen and Maastricht). As already explained, when an emission constraint is applied, investment are lower, but only based on clean technologies. Recall that they totally amount to 29,242 MW, of which 26,641 is represented by nuclear (in France) and the residual 2,600 MW are renewable (in Merchtem). As reported in Table 5.21, total emissions equal the carbon cap of about 359 Mio ton p.a. and the endogenous allowance price is 19.21 €/ton.

		AP-ENDO	**AP20**	**AP70**
NETS_IR	80,629			
ETS_IR		67,388	66,911	56,660
ETS_ISAC		65,641	66,856	64,445
ETS_INAC		69,758	68,981	65,204

Table 5.20: EIIs' Hourly Electricity Demand under Different Investment and Allowance Price Scenarios in MWh

Reference Model under the AP20 Scenario

Generators do not change their investment strategy, when we fix an allowance price of 20 €/ton. Like in the endogenous allowance price version (AP-endo hereafter) of the reference model, generators still invest in renewable and nuclear power stations. Their locations do not change. The higher carbon cost provokes an augment of electricity prices and then both N-EIIs and EIIs lessen their power consumption with respect to the AP-endo version of the ETS_IR model[35] (see Tables 5.20, 5.22 and 5.23). Nevertheless, investments amounts to 30,300 MW (+4% with respect to the AP-endo case). The combination of demand and investment effects explains why total emission level is 3% lower than the cap imposed in the ETS_IR model (see Table 5.21).

Reference Model under the AP70 Scenario

The imposition of the 70 €/ton allowance price forces generators to completely modify their technology mix. First, the investment level of this AP70 version of the ETS_IR case is almost double than in ETS_IR AP-endo model. The new power capacity built amounts to 58,107 MW, of which 42% of renewable, 46% of nuclear and 12% of CCGT. New nuclear plants are constructed in France, renewable in Germany and in Merchtem and finally CCGT in Germany only. Generators run also existing hydro, renewable, nuclear and CCGT. This latter technology is mainly exploited in winter.

Due the implementation of this restrictive environmental policy, nuclear power plants define the summer electricity prices. This makes electricity cheaper than in the ETS_IR AP-endo case and allows N-EIIs to increase their electricity demand by 2%. In winter, prices are instead quite high since they are determined by CCGT augmented by its emission opportunity cost. For this reason, N-EIIs' demand falls by 4% with respect to ETS_IR AP-endo case (see respectively Tables 5.22 and 5.23).

On the other side, industries globally reduce their electricity consumption by 16% with respect to their level in the AP-endo case (see Table 5.20). This significant cut depends on the mechanism adopted to model EIIs' demand. In fact, we assume that EIIs' power consumption is constant over time and then the 16% drop is caused by the huge increase of electricity price in winter. Note that Dutch industries are particularly negatively affected by the AP70 environmental policy since they face quite high electricity price both in summer and in winter[36].

Finally, carbon emissions are only generated by CCGT plants and amount to 59 Mio ton p.a. This represents the expected outcome of the restrictive environmental policy applied.

		AP-ENDO	**AP20**	**AP70**
NETS_IR	559			
ETS_IR		359	349	59
ETS_ISAC		359	389	74
ETS_INAC		359	354	56

Table 5.21: Emission Levels under Different Investment and Allowance Price Scenarios in Mio ton p.a.

Average Cost Pricing Models

Energy intensive industries partially recover their lost demand by concluding long-term contracts with generators. With the introduction of the average cost pricing system, power companies split old and

[35]The increment of 4% of the allowance price implies reductions of 0.7% of EIIs' global hourly demand and 0.1% and 0.05% of N-EIIs' consumption respectively in summer and in winter.

[36]Their demand reductions computed with respect to the ETS_IR AP-endo model are 76%, 65% and 54% respectively in Krimpen, Maastricht and Zwolle.

new plants between the two consumer groups. Whatever the different allowance price scenarios tested, the nodal average cost pricing system performs better than the ETS_IR and the ETS_ISAC cases (see Table 5.20).

Summer				
		AP-ENDO	**AP20**	**AP70**
NETS_IR	48,910			
ETS_IR		47,777	47,737	48,384
ETS_ISAC		47,498	47,737	48,380
ETS_INAC		47,777	47,740	48,373

Table 5.22: N-EIIs' Summer Electricity Demand under Different Investment and Allowance Price Scenarios in MWh

Winter				
		AP-ENDO	**AP20**	**AP70**
NETS_IR	114,155			
ETS_IR		112,731	112,675	107,382
ETS_ISAC		111,955	111,134	107,128
ETS_INAC		112,738	112,691	107,819

Table 5.23: N-EIIs' Winter Electricity Demand under Different Investment and Allowance Price Scenarios in MWh

Single Average Cost Pricing Model under the AP20 Scenario

With a CO_2 allowance costs of 20 €/ton, generators invest in renewable (in Merchtem), in nuclear (in France), in lignite (in Germany) and in coal (in Krimpen) both for N-EIIs and EIIs. Globally investments amount to 23,979 MW of which 65% is dedicated to industries (8% less with respect to the AP-endo version of the ETS_ISAC case). Nuclear has the highest contribution (79%), followed by renewable (18%), lignite (2%) and coal (1%). Little investments in dirty technologies appear since, in this AP20 scenario, carbon is less expensive (-19%) than in the AP-endo case of the ETS_ISAC model where the allowance price turned out to be 24.80 €/ton. The reduced carbon price has a positive impact on the single average cost price that is 2% lower than in AP-endo case of the ETS_ISAC model[37]. It drops to 35.82 €/MWh (AP20) from 36.62 €/MWh (AP-endo). This implies an increase of EIIs' electricity demand of 1.9% with respect to the AP-endo case of the ETS_ISAC model (see Table 5.20). The AP20 policy has a double impact on N-EIIs which raise their electricity demand in summer and reduce their consumption in winter (see Tables 5.22 and 5.23). Note that their prices are determined by coal and CCGT (augmented by the emission opportunity costs) respectively in summer and in winter. These technologies also influence emissions that are 8% higher than the imposed cap of 359 Mio ton p.a. (see Table 5.21). In fact, due to the lower carbon price all technologies, expect for old gas and oil, are operated in order to supply both EIIs and N-EIIs.

[37]In the AP20 and AP-endo scenarios of the ETS_ISAC model, the fuel mix adopted to supply EIIs is identical. It includes clean technologies, lignite, coal and CCGT. However, they contribute in a different ways to the formation of the price. This implies different average fix costs that are lower in the AP20 case.

Single Average Cost Pricing Model under the AP70 Scenario

With an allowance price of 70 €/ton, the tendency observed is similar to that described in the AP70 scenario of the ETS_IR model. Globally, the new available capacity amounts to 65,107 MW of which 56% is renewable (in Germany and in Merchtem), 29% is nuclear (in France) and 11% CCGT (in the Dutch node Krimpen). The split in capacity assigns 54% of these new technologies to industries and the rest to N-EIIs. These (old and new) power stations in addition to existing hydro plants are used to supplied both market segments. Renewable contributes a lot to the production of electricity for EIIs. The single average cost price in this AP70 scenario (37.41 €/MWh) is higher[38] than in the AP20 and AP-endo versions of the ETS_ISAC model (see Table 5.20). The situation faced by N-EIIs is identical to that described in the reference case under the AP70 assumption (see Tables 5.22 and 5.23). Again, due to the significant utilization of clean technologies, global emissions are quite low (see Table 5.21).

Nodal Average Cost Pricing Model under the AP20 Scenario

Both under the AP20 and the AP70 scenarios, EIIs would prefer the application of the nodal average cost pricing system with respect to the single one. Generators behave like in the AP-endo version of the ETS_INAC model and invest more for N-EIIs than for EIIs (both in AP20 and the AP70 cases).

In particular, in the AP20 cases, the new capacity totally amounts to 32,053 MW of which 64% devoted to N-EIIs and the residual 36% to EIIs. Generators invest in nuclear in France and in renewable in the Belgian nodes. N-EIIs' electricity prices are still determined by coal and CCGT (augmented by the emission opportunity cost) respectively in summer and in winter. These prices are slightly higher than in the AP-endo version of ETS_INAC case and then N-EIIs reduce their electricity demand both in summer (-0.08%) and in winter (-0.04%). This is due to the fact that, in this AP20 scenario, the allowance price is slightly higher than in the AP-endo version of the ETS_INAC model. This also explains the 3% cut of emissions with respect to our cap of 359 Mio ton (see Table 5.21).

EIIs' demand under AP20 scenario is 1% lower than in the AP-endo case of the ETS_INAC model, but it is 3% higher than in the AP20 case of the ETS_IR model. This 1% cut mainly depends on the different capacity allocation and the higher allowance prices. The 3% augment is driven by the increase of EIIs' demand in the German, French and Belgian nodes where generators invest. Again, due to the high capacity costs[39] generators do not invest in the Dutch nodes and exploit only existing capacity to supply local EIIs which react by decreasing their electricity consumption[40].

Nodal Average Cost Pricing Model under the AP70 Scenario

The results of the AP70 version of the nodal average cost model show an investment increase of +110% with respect to the ETS_IR AP70. Globally, new capacity amounts to 67,269 MW, of which 59% goes to N-EIIs and the remaining 41% to EIIs. Generators invest in renewable (in Germany and in Gramme), in nuclear (in France) and in CCGT (in Germany) for N-EIIs; while only in renewable for

[38]Relative changes are +4% and +2% in comparison with the AP20 and the AP-endo cases of the single average cost model. This phenomenon depends both on the high carbon costs and the different contribution of fixed costs. In spite of CCGT and coal plants, clean technologies do not emit but are characterized by high capacity costs.

[39]This depends on our input data, see Chapter 2.

[40]Decreases computed with respect to the ETS_IR case with endogenous allowance price are -9% (in Krimpen), -2% (in Maastricht) and -2% (in Zwolle).

EIIs[41]. Again, no investments are reserved for Dutch energy intensive industries[42]. This significantly damage Dutch industries that react by reducing their electricity consumption. In particular, they stop to consume electricity in Maastricht and in Zwolle where the local available technologies lead to electricity prices that are too high[43].

Tables 5.22 and 5.23 report N-EIIs' electricity consumption respectively in summer and in winter. This is aligned with the tendency observed in the other AP70 cases. Finally, the high investments in clean technologies explain the low amount of emission generated (56 Mio ton p.a.). This sensitivity analysis confirms the results found in Section 4.5 of Chapter 4. As already observed, ETS drives investments towards clean technologies. This tendency is particularly evident when one imposes a very restrictive target[44]. Again, the application of average cost based contracts partially mitigates the carbon burdens faced by EIIs.

5.7 Alternative Solutions to the Single and the Nodal Average Cost Models

In this Section, we propose a sample of the results obtained by modifying the starting point of the implementation of the single and the nodal average cost models. As discussed in Section 5.3, before implementing the average cost models, we simulate a scenario of a perfectly competitive market (the preliminary model), where EIIs and N-EIIs are supplied by dedicated capacities, but they buy electricity at the marginal price. The outcome of this scenario is adopted to find the solution to the average cost pricing models. These lead to the results presented in this Chapter. We followed this strategy in order to reduce computational difficulties created by the non-convexity of the average cost models. However, our average cost models have solution also without considering this preliminary model. In this way, the starting point changes. The results obtained by running the average cost models without the preliminary scenario are different from those described in the first part of this Chapter. This means that non-convexity leads to a multiplicity of (disjoint) solutions. We report part of these new results and in particular we consider the EIIs' demand and the investments reserved for the two market segments.

5.7.1 Single Average Cost Model

Generators' investment policy does not change: they still build new nuclear in France and new renewable plants in Germany and in the Belgian location Merchtem. Total investments amount to 23,945 MW (see Tables 5.24 and 5.25). These are 9% lower than in the case with preliminary model, but the proportion reserved for EIIs is higher[45]. This different investment allocation leads also to

[41] These new renewable plants are constructed in Germany, in Merchtem and in Gramme.

[42] Generators are not encouraged to built new power plants in the Netherlands since it is too costly. This indeed depends on our input data (see Chapter 2).

[43] Recall that in the Netherlands, electricity production is mainly based on coal and CCGT. Hydro is not available and moreover, generators do not receive incentives to invest in renewable (according to our input data). With the allowance cost of 70 €/ton, the electricity locally produced becomes too expensive and EIIs do not buy it. Note that in Kripem, EIIs' demand amounts to 387 MWh that corresponds exactly to the MW of CCGT that generators dedicate to them.

[44] We model a very restrictive environmental policy by setting a high allowance price (70 €/ton). A similar result can be obtained by imposing a very low cap. In the first approach, allowance price is exogenous while in the second is endogenous.

[45] It corresponds to 89%.

a different split of existing capacities. However, coal and CCGT still fix the marginal cost prices respectively in summer and in winter. Finally, allowance price is identical in both scenarios (24.80 €/ton).

	Germany	**France**	**Merchtem**	**Total**
Renewable	1,749		3,832	**5,580**
Nuclear		15,759		**15,759**
Total	**1,749**	**15,759**	**3,832**	**21,339**

Table 5.24: Investments for EIIs in the ETS_ISAC Scenario Without the Preliminary Model in MW

	Germany	**France**	**Merchtem**	**Total**
Renewable	340		38	**378**
Nuclear		2,228		**2,228**
Total	**340**	**2,228**	**38**	**2,606**

Table 5.25: Investments for N-EIIs in the ETS_ISAC Scenario Without the Preliminary Model in MW

In Table 5.26, we compare the EIIs' nodal demand in the single average cases with and without the preliminary model (PM). The industrial electricity consumption drops by 4% when the preliminary model is not implemented. This is a direct reaction to the increase of the single average price that now amounts to 38.28 €/MWh against the 36.62 €/MWh of the case with preliminary model.

	With PM	**Without PM**
Germany	32,159	30,932
France	20,091	19,325
Merchtem	4,670	4,491
Gramme	2,007	1,931
Krimpen	3,435	3,304
Maastricht	1,173	1,129
Zwolle	2,105	2,025
Total	**65,641**	**63,136**

Table 5.26: EIIs' Electricity Demand in the ETS_ISAC Scenario With and Without the Preliminary Model in MWh

5.7.2 Nodal Average Cost Model

The comparison between the nodal average cost cases with and without the preliminary model confirms the tendency found for the single average cost case. In particular, EIIs' electricity consumption in the nodal scenario without PM is lower than in the case with PM, even though the cut is only 1% (see Table 5.27).

Generators change their investment policy by increasing the capacity dedicated to industries and reducing that reserved for N-EIIs (see Tables 5.27 and 5.28). In particular, the new plants built for EIIs amount to 12,620 MW against the 2,458 MW in the nodal average cost case PM. The 74% of these new plants is represented by nuclear in France and the rest is renewable located in Merchtem

	With PM	**Without PM**
Germany	28,875	29,391
France	29,002	28,235
Merchtem	5,040	4,710
Gramme	2,635	2,679
Krimpen	2,473	2,315
Maastricht	561	561
Zwolle	1,173	1,173
Total	**69,758**	**69,064**

Table 5.27: EIIs' Demand in the ETS_INAC Scenario With and Without the Preliminary Model in MWh

and in Gramme. On the other side, N-EIIs receive 18,749 MW of new capacity composed of nuclear in France and renewable in Merchtem. N-EIIs' electricity prices are still determined by coal and CCGT augmented by the corresponding emission opportunity costs. The allowance price is 19.26 €/ton like in the case with PM.

	France	**Merchtem**	**Gramme**	**Total**
Renewable		2,907	365	**3,272**
Nuclear	9,348			**9,348**
Total	**9,348**	**2,907**	**365**	**12,620**

Table 5.28: Investments for EIIs in the ETS_INAC Scenario Without the Preliminary Model in MW

	France	**Merchtem**	**Total**
Renewable		945	**945**
Nuclear	17,804		**17,804**
Total	**17,804**	**945**	**18,749**

Table 5.29: Investments for N-EIIs in the ETS_INAC Scenario Without the Preliminary Model in MW

5.8 Conclusion

In this Chapter, we explore the combined effects of the EU-ETS and of average cost based contracts based on investment choices in the power sector. Both investments and emission regulations affect electricity prices and demand. Investments generally allow EIIs and N-EIIs to increase their electricity demand, but this positive effect is not sufficient to compensate for the additional burdens caused by the EU-ETS.

The implementation of long-term contracts shows that nodal average cost pricing policy has a global positive influence on industrial consumers. Their global electricity consumption in the ETS_NAC case is higher than in the single average cost model, where their demand is even lower than in the reference investment model. However a more detailed analysis highlights that industries' behaviour changes in accordance with their locations and the average cost based contract introduced. Belgian and French intensive users of electricity prefer buying power at the nodal average cost prices. In contrast, in Germany and in the Netherlands, the optimal solution would be the implementation of the single average cost price mechanism.

The EU-ETS drives investments and encourages power companies to build new renewable and nuclear plants. Our sensitivity analysis confirms that allowance price is the real factor that affects investments: the higher the carbon cost is and the larger are investment in clean technologies. Certainly less obvious is the fact that the higher is the emission contract (or the allowance price) the more the nodal average cost pricing system helps recovering the lost demand, but also the higher the distortion of competition among European regions.

In the next Chapter, we present the results of the last extension of our models. We account in fact for the case where energy intensive industries participate to the emission market and face the direct ETS costs.

5.9 Appendix: Further Results of the Four Scenarios under Investment Assumptions

In this Appendix, we present some additional results of the problem studied. In particular, the Tables below provide information on electricity generation by period, node and technology, old capacity splitting and investments by company, node and technology. Their content has already been explained in the previous Section of this Chapter.

SUMMER						
	Hydro	**Renewable**	**Nuclear**	**Lignite**	**Coal**	**Total**
Germany	1,505	4,584	15,007	17,783		38,879
France	6,084	1	30,617			36,702
Merchtem		20	2,078		1,564	3,662
Gramme	13	21	2,204		19	2,257
Krimpen		101	337		3,128	3,566
Maastricth		101				101
Zwolle		101			482	583
Total	**7,602**	**4,930**	**50,243**	**17,783**	**5,193**	**85,751**

Table 5.30: Summer Electricity Generation with Existing Capacity in the NETS_IR Scenario in MWh

WINTER							
	Hydro	**Renewable**	**Nuclear**	**Lignite**	**Coal**	**CCGT**	**Total**
Germany	1,505	4,584	15,007	17,783	24,613	3,307	**66,799**
France	6,084	1	45,369	77	8,824		**60,355**
Merchtem		20	2,078		1,564	2,469	**6,131**
Gramme	13	21	2,204		979		**3,217**
Krimpen		101	337		3,128	3,683	**7,249**
Maastricth		101				1,726	**1,827**
Zwolle		101			482	4,834	**5,417**
Total	**7,602**	**4,930**	**64,995**	**17,860**	**39,590**	**16,019**	**150,996**

Table 5.31: Winter Electricity Generation with Existing Capacity in the NETS_IR Scenario in MWh

SUMMER							
	Hydro	**Renewable**	**Nuclear**	**Lignite**	**Coal**	**CCGT**	**Total**
Germany	1,505	4,584	15,007	17,783	6,814		**45,694**
France	6,084	1	21,718				**27,803**
Merchtem		20	2,078		1,072		**3,171**
Gramme	13	21	2,204				**2,238**
Krimpen		101	337		3,128	1,684	**5,250**
Maastricth		101				1,082	**1,183**
Zwolle		101			482		**583**
Total	**7,602**	**4,930**	**41,344**	**17,783**	**11,497**	**2,766**	**85,923**

Table 5.32: Summer Electricity Generation with Existing Capacity in the ETS_IR Scenario in MWh

WINTER							
	Hydro	**Renewable**	**Nuclear**	**Lignite**	**Coal**	**CCGT**	**Total**
Germany	1,505	4,584	15,007	17,783	24,613	10,429	**73,921**
France	6,084	1	45,369	77			**51,531**
Merchtem		20	2,078		1,564	2,589	**6,251**
Gramme	13	21	2,204		979		**3,217**
Krimpen		101	337		3,128	4,432	**7,998**
Maastricth		101				2,440	**2,541**
Zwolle		101			482	4,834	**5,417**
Total	**7,602**	**4,930**	**64,995**	**17,860**	**30,766**	**24,724**	**150,877**

Table 5.33: Winter Hourly Electricity Generation with Existing Capacity in the ETS_IR Scenario in MWh

	Hydro	Renewable	Nuclear	Lignite	Coal	CCGT	Total
Germany	807	2,296	7,277	8,535	5,634		**24,549**
France	1,583	1	18,127				**19,711**
Merchtem			838				**838**
Gramme	1	1	746				**748**
Krimpen		68	69		625	768	**1,530**
Maastricht		54				538	**592**
Zwolle		44			228		**272**
Total	**2,391**	**2,464**	**27,058**	**8,535**	**6,487**	**1,306**	**48,241**

Table 5.34: Electricity Generation with Existing Capacity for EIIs in the ETS_ISAC Scenario in MWh

SUMMER							
	Hydro	**Renewable**	**Nuclear**	**Lignite**	**Coal**	**CCGT**	**Total**
Germany	698	2,288	7,730	9,248	1,545		**21,509**
France	4,501		4,009				**8,510**
Merchtem		20	1,240				**1,260**
Gramme	12	20	1,458				**1,490**
Krimpen		33	268		2,503	1,568	**4,373**
Maastricth		47				1,202	**1,249**
Zwolle		57			254		**311**
Total	**5,211**	**2,466**	**14,704**	**9,248**	**4,302**	**2,771**	**38,703**

Table 5.35: Summer Electricity Generation with Existing Capacity for N-EIIs in the ETS_ISAC Scenario in MWh

WINTER							
	Hydro	**Renewable**	**Nuclear**	**Lignite**	**Coal**	**CCGT**	**Total**
Germany	698	2,288	7,730	9,248	18,979	11,798	**50,741**
France	4,501	0	27,242				**31,743**
Merchtem		20	1,240		1,564	1,400	**4,224**
Gramme	12	20	1,458		922	0	**2,412**
Krimpen		33	268		2,503	3,664	**6,468**
Maastricth		47				2,379	**2,426**
Zwolle		57			254	4,834	**5,145**
Total	**5,211**	**2,466**	**37,937**	**9,248**	**24,222**	**24,075**	**103,159**

Table 5.36: Winter Electricity Generation with Existing Capacity for N-EIIs in the ETS_ISAC Scenario in MWh

	Hydro	Renewable	Nuclear	Lignite	Coal	CCGT	Total
Germany	600	4,584	6,228	14,927	2,536		**28,875**
France			29,002				**29,002**
Merchtem			2,034		548		**2,582**
Gramme	13	21	2,204		396		**2,635**
Krimpen		9	337		1,243	883	**2,473**
Maastricht		101				460	**561**
Zwolle		101			482	589	**1,173**
Total	**613**	**4,817**	**39,805**	**14,927**	**5,206**	**1,932**	**67,299**

Table 5.37: Electricity Generation with Existing Capacity for EIIs in the ETS_INAC Scenario in MWh

SUMMER						
	Hydro	**Renewable**	**Nuclear**	**Lignite**	**Coal**	**Total**
Germany	906	0	8,779	2,856	4,903	**17,444**
France	6,084	1	1,003	0	0	**7,088**
Merchtem	0	20	44	0	0	**64**
Gramme	0	0	0	0	0	**0**
Krimpen	0	92	0	0	1,885	**1,977**
Maastricth	0	0	0	0	0	**0**
Zwolle	0	0	0	0	0	**0**
Total	**6,990**	**113**	**9,826**	**2,856**	**6,788**	**26,573**

Table 5.38: Summer Electricity Generation with Existing Capacity for N-EIIs in the ETS_INAC Scenario in MWh

WINTER							
	Hydro	**Renewable**	**Nuclear**	**Lignite**	**Coal**	**CCGT**	**Total**
Germany	906		8,779	2,856	22,077	11,506	**46,123**
France	6,084	1	16,367	77			**22,529**
Merchtem		20	44		1,016	2,292	**3,372**
Gramme					583	655	**1,238**
Krimpen		92			1,885	3,549	**5,526**
Maastricth						171	**171**
Zwolle						4,245	**4,245**
Total	**6,990**	**113**	**25,190**	**2,933**	**25,560**	**22,418**	**83,204**

Table 5.39: Winter Hourly Electricity Generation with Existing Capacity for N-EIIs in the ETS_ISAC Scenario in MWh

	Hydro	Renewable	Nuclear	Lignite	Coal	CCGT
Germany	54%	50%	48%	48%	23%	
France	26%	94%	40%			
Merchtem			40%			
Gramme	7%	4%	34%			
Krimpen		67%	21%		20%	17%
Maastricht		54%				18%
Zwolle		43%			47%	
Total	**31%**	**50%**	**42%**	**48%**	**16%**	**3%**

Table 5.40: Proportions of Existing Capacity Dedicated to EIIs in the ETS_ISAC

	Hydro	Renewable	Nuclear	Lignite	Coal	CCGT
Germany	40%	100%	42%	84%	10%	
France			64%			
Merchtem			98%		35%	
Gramme	100%	100%	100%		40%	
Krimpen		9%	100%		40%	20%
Maastricht		100%				16%
Zwolle		100%			100%	12%
Total	8%	98%	61%	84%	13%	5%

Table 5.41: Proportions of Existing Capacity Dedicated to EIIs in the ETS_INAC

		Nuclear	Lignite	Coal	Total
EoN	*France*	2,377			
	Merchtem			381	
	Krimpen			236	
	Maastricht			171	**3,164**
Electrabel	*France*	1,837			
	Merchtem			83	
	Krimpen			461	
	Maastricht			171	**2,551**
EdF	*Merchtem*			381	
	Krimpen			466	
	Maastricht			171	**1,017**
EnBW	*France*	2,307			
	Merchtem			381	
	Krimpen			466	
	Maastricht			171	**3,324**
Essent	*France*	2,377			
	Merchtem			381	
	Krimpen			132	
	Maastricht			97	**2,987**
Nuon	*France*	2,377			
	Merchtem			381	
	Krimpen			132	
	Maastricht			167	**3,057**
RWE	*Germany*		18,570		
	France	2,377			
	Merchtem			381	
	Krimpen			466	
	Maastricht			171	**21,964**
Vattenfall	*France*	2,377			
	Merchtem			381	
	Krimpen			466	
	Maastricht			171	**3,394**
Fringe	*France*	1,769			
	Merchtem			331	
	Krimpen			132	
	Maastricht			97	**2,329**
Total		**17,799**	**18,570**	**7,419**	**43,788**

Table 5.42: Investments in the NETS_IR Scenario in MW

		Renewable	**Nuclear**	**Total**
EoN	*France*		3,423	
	Merchtem	297		**3,720**
Electrabel	*France*		2,883	
	Merchtem	243		**3,126**
EdF	*France*		0	
	Merchtem	297		**297**
EnBW	*France*		3,353	
	Merchtem	297		**3,650**
Essent	*France*		3,423	
	Merchtem	297		**3,720**
Nuon	*France*		3,423	
	Merchtem	297		**3,720**
RWE	*France*		3,423	
	Merchtem	297		**3,720**
Vattenfall	*France*		3,423	
	Merchtem	297		**3,720**
Fringe	*France*		3,289	
	Merchtem	278		**3,567**
Total		**2,600**	**26,641**	**29,242**

Table 5.43: Investments in the ETS_IR Scenario in MW

		Renewable	Nuclear	Total
EoN	*Germany*	204		
	France		1,658	
	Merchtem	343		**2,204**
Electrabel	*Germany*	198		
	France		1,118	
	Merchtem	602		**1,918**
EdF	*Germany*	188		
	Merchtem	343		**531**
EnBW	*Germany*	201		
	France		1,473	
	Merchtem	343		**2,018**
Essent	*Germany*	194		
	France		1,658	
	Merchtem	343		**2,194**
Nuon	*Germany*	188		
	France		1,658	
	Merchtem	343		**2,189**
RWE	*Germany*	204		
	France		1,658	
	Merchtem	343		**2,205**
Vattenfall	*Germany*	201		
	France		1,658	
	Merchtem	343		**2,202**
Fringe	*Germany*	148		
	France		1,485	
	Merchtem	307		**1,940**
Total		**5,035**	**12,365**	**17,400**

Table 5.44: Investments for EIIs in the ETS_ISAC Scenario in MW

		Renewable	Nuclear	Total
EoN	*Germany*	219		
	France		833	
	Merchtem	69		**1,121**
Electrabel	*Germany*	230		
	France		394	
	Merchtem	220		**844**
EdF	*Germany*	232		
	Merchtem	69		**300**
EnBW	*Germany*	221		
	France		820	
	Merchtem	69		**1,110**
Essent	*Germany*	226		
	France		833	
	Merchtem	69		**1,128**
Nuon	*Germany*	232		
	France		833	
	Merchtem	69		**1,133**
RWE	*Germany*	219		
	France		833	
	Merchtem	69		**1,121**
Vattenfall	*Germany*	222		
	France		833	
	Merchtem	69		**1,124**
Fringe	*Germany*	85		
	France		728	
	Merchtem	102		**915**
Total		**2,690**	**6,106**	**8,796**

Table 5.45: Investments for N-EIIs in the ETS_ISAC Scenario in MW

		Renewable
EnBW	*Merchtem*	2,260
RWE	*Merchtem*	198
Total		**2,458**

Table 5.46: Investments for EIIs in the ETS_INAC Scenario in MW

		Renewable	Nuclear	Total
Electrabel	*Merchtem*	1,620		**1,620**
Essent	*France*		27,913	**27,913**
Total		**1,620**	**27,913**	**29,533**

Table 5.47: Investments for N-EIIs in the ETS_INAC Scenario in MW

Chapter 6

Analysis of the Direct and Indirect Impacts of the EU-ETS on Energy Intensive Industries

6.1 Introduction

The objective of this Chapter is to investigate both the direct and the indirect impacts of the EU-ETS on energy intensive industries. This represents the third stage of our analysis. Recall that, the *direct* impact is the cost of allowances that industries buy on the emission market; while the *indirect* impact is the one resulting from the increased electricity price. As explained in the Introduction, the contribution of the direct and indirect impacts on the EU-ETS differs by industrial sector and production activity considered (Demailly and Quirion [6], Hourcade et al. [30], McKinsey and Ecofys [33] and Renaiud [44]). In Chapters 4 and 5, we examined the problem of the indirect carbon charge. In accordance with the scope of our analysis, we explored the extent to which the application of average cost based contracts may mitigate the problem of the increasing electricity price. The effectiveness of implementation of these long-term contracts is detected by presenting the EIIs' reaction through an electricity demand function. Starting from these assumptions and without changing our final goal, we extend the formulation of the models presented in Chapter 4 and 5 in order to account also for the direct impact of the EU-ETS on energy intensive industries. Because of the lack of information on the separate reactions of EIIs though electricity and allowances prices, the modelling of their direct reaction will require some modifications of our representation of the emission market and the modelling of industrial electricity price. This obviously influences EIIs' power consumption. These model variants are describes in Section 6.2; while in Section 6.3 we explains the results of this policy. Because of the multiplicity of effects involved (direct and indirect ETS impacts, investment strategies and long-term contracts), the analysis becomes more complex. For this reason, we postpone the detailed presentation of the results to Appendix 6.5. This may help the reading and avoid too many repetitions. We conclude with final remarks in Section 6.4.

6.2 Mathematical Formulation

In this Chapter, we complete our study by adding the formalization of direct costs caused by the ETS on industrial sectors. Taking as references the models presented in Chapters 3 and 5, we modify the emission constraint and the EIIs' electricity demand function. This is the main novelty of these models compared to those of the preceding Chapters. As already explained in Section 2.1.4 of Chapter 2, we now assume that the final price paid by industrial consumers is modified to account for the direct effect of the ETS, namely the cost of emission allowances. In other words, industrial electricity demand now depends on two factors: the pure electricity price (as in the previous models) and a carbon component defining the industrial allowances trading on the carbon market.

The final industrial electricity consumption therefore is a function of two prices which respectively represent the indirect and the direct carbon charges. We apply the following reasoning to define the direct ETS impact on energy intensive industries. The EIIs' emission level depends on their production activities which, in turn, affect their electricity consumption. The more industries produce, the higher is the amount of electricity needed as well as the level of emission generated. By a transitive property, EIIs' emissions are positively related to their electricity consumption.

For this reason, we can study the industrial response to the direct carbon cost by using their electricity demand function. We consider two different scenarios: one without ("EIINA" hereafter) and one with ("EIIA" hereafter) free allowance allocations for industries. We assume that free allowances to industries are received proportionally to their production (and then electricity consumption). Note that this is our major policy assumption. In fact, it is not clear from the current legislative proposal for the period after 2012 what the policy towards industrial sectors will be. At point 8 of Article 10a of the proposed revision of the Directive 2003/87/EC, it is states that *in 2013 and in each subsequent year up to 2020, installations in sectors which are exposed to a significant risk of carbon leakage shall be allocated allowances free of charge which may be up to 100 percent of the quantity determined in accordance with paragraphs 2 to 7.*

Due to this uncertainty, we assume that the European law could envisage giving free allowances proportional to output (but not emissions) to EIIs because they are subject to international competitiveness. We make this economic assumption, not because we believe that it is particularly plausible from a political point of view, but as a first step of analysis. The formalization of these new models is as follows. We first use a nomenclature different from that adopted in the previous Chapters, but come back to our standard notation afterwords. Our aim here is to show the methodology adopted to model this new assumption.

We start by considering the profit function π of energy intensive industries. Note that because of the lack information, we define industries as an aggregated sector. We are aware of the fact that it is not a sufficient representation of the system, but at least it allows us to illustrate the phenomenon studied. A description of the industrial sectors on a technological basis would be more realistic, but we do not dispose of such a kind of information. For this reason, we limit ourselves to aggregate energy intensive industries in one sector and to study their reactions to the EU-ETS by the means of their electricity demand function.

$$\pi = p_y \cdot y - p_e \cdot e - p_o \cdot o - p_{co_2} \cdot co_2 \tag{6.1}$$

Industries' revenues accrue from selling their output y at the price p_y. They need some inputs and electricity to produce their output. For the sake of simplicity, we assume that industries buy electricity e at a price p_e from power companies and some other inputs o at price p_o from other suppliers. Moreover, with the implementation of the EU-ETS, industries buy allowances co_2 at a price p_{co_2}. Note that co_2 represents the quantity of allowances that EIIs purchase on the carbon market, i.e. it corresponds to the amount of emissions reduced by the allowances received for free. Recall that we assume free allowances proportional to production; the standard reasoning in term of opportunity costs no longer holds. As already explained, the amount of electricity e, allowances co_2 and input o demanded by EIIs varies proportionally to their production activities. The general formulation is as follows:

- $e = \alpha \cdot f(y)$
- $co_2 = (\beta - \gamma) \cdot g(y)$
- $o = \varphi(y)$

The parameter α represents the proportion of electricity needed per unit of output produced. β defines the emission factor per unit of output y; while γ is the proportion of free allowances received by unit y.

However, because of the lack of information for holding these more complex assumptions, we state a linear dependence between the demand of energy e and allowances co_2 and the industrial production y. By considering this simplification, the equalities indicated above become as follows:

- $e = \alpha \cdot y$ (Electricity consumption is proportional to output)
- $co_2 = (\beta - \gamma) \cdot y$ (co_2 emissions are proportional to output)
- $o = \varphi(y)$ (Inputs are proportional to output)

In this way, we can write (6.1) as a function of the sole output y. We get:

$$\pi(y) = p_y \cdot y - p_e \cdot \alpha \cdot y - p_{co_2} \cdot (\beta - \gamma) \cdot y - p_o \cdot \varphi(y) \tag{6.2}$$

In accordance with the approach used in our analysis, we want to establish the industrial demand of electricity. To do that, we compute the First Order Conditions (FOC) of (6.2) with respect to y and obtain:

$$\frac{\partial \pi}{\partial y} = p_y - p_e \cdot \alpha - p_{co_2} \cdot (\beta - \gamma) - p_o \cdot \varphi'(y) = 0 \tag{6.3}$$

To the aim of our analysis, we are interested in isolating the electricity price (p_e), which measures the indirect ETS costs and the allowance price (p_{co_2}) which determines the direct carbon cost. We then re-write condition (6.3) in the following way:

$$p_e \cdot \alpha + p_{co_2} \cdot (\beta - \gamma) = p_y - p_o \cdot \varphi^{'}(y) \tag{6.4}$$

Diving by α on the left and right hand sides of equation (6.4), one gets:

$$p_e + p_{co_2} \cdot (\frac{\beta - \gamma}{\alpha}) = \frac{1}{\alpha}\left[p_y - p_o \cdot \varphi'(y)\right] \tag{6.5}$$

Assuming that $\varphi^{'}(y) = a + b \cdot y$, then we have:

$$p_e + p_{co_2} \cdot (\frac{\beta - \gamma}{\alpha}) = \frac{1}{\alpha}\left[p_y - p_o \cdot (a + b \cdot y)\right] \tag{6.6}$$

From the relation between industrial electricity consumption and production $e = \alpha \cdot y$, we know that $y = e/\alpha$. We substitute this expression in (6.6) and we obtain:

$$p_e + p_{co_2} \cdot (\frac{\beta - \gamma}{\alpha}) = p_y \frac{1}{\alpha} - p_o \frac{a}{\alpha} - p_o \frac{b}{\alpha^2} e \qquad (6.7)$$

By setting $A = p_y \frac{1}{\alpha} - p_o \frac{a}{\alpha}$ and $B = p_o \frac{b}{\alpha^2}$, we have:

$$p_e + p_{co_2} \cdot (\frac{\beta - \gamma}{\alpha}) = A - Be \qquad (6.8)$$

Equation (6.8) represents the industrial demand of electricity, where p_e and e are respectively the EIIs' electricity price and demand. It includes also the emission allowance price p_{co_2} multiplied by the factor $(\frac{\beta-\gamma}{\alpha})$ which defines the impact of the application of different emission policies on EIIs. In fact, we can consider the following scenarios:

1. Allowances are completely grandfathered ($\beta = \gamma$). This is in line with the situation registered in the (2005-2007) EU-ETS phase;

2. Allowances are completely auctioned ($\gamma = 0$). This is what is foreseen for the period after 2012 by the proposed new ETS Directive;

3. Allowance are partially grandfathered ($\beta \neq \gamma$). This is a more general situation which can represent a declining free allowance allocation for EIIs or again a full free allocation as foreseen by the proposed new ETS Directive in case where industries become too exposed to carbon leakage.

The industrial electricity demand function (6.8) is then inserted in our (partial) equilibrium models where electricity, emission and transmission prices are endogenously determined. The emission allowance price p_{co_2} is also included in the EIIs' demand function.

Our analysis considers two different situations for EIIs. In a first case, named “EIINA”, we assume that no free allowances are given to EIIs. It corresponds to a situation of full auctioning and it is simply modelled by setting the value of γ equal to zero. In this way, the factor $(\frac{\beta-\gamma}{\alpha})$ becomes $(\frac{\beta}{\alpha})$ and we refer to it as the “emission factor”. We consider also the scenario “EIIA” where industries receive free allowances proportionally to their production (and then electricity consumption). The factor $(\frac{\beta-\gamma}{\alpha})$ remains unchanged and we call it “allowance factor”. Both approaches are aligned with what foreseen by the proposal of new ETS Directive. In the “EIINA”, will we have an emission component in the industrial electricity demand represented by $p_{co_2} \cdot \frac{\beta}{\alpha}$; while in the “EIIA” scenario we will consider the allowance component $p_{co_2} \cdot \frac{\beta-\gamma}{\alpha}$. The industrial demand of allowances is then represented by:

$$allowance \quad demand = \frac{\beta - \gamma}{\alpha} \cdot e$$

In accordance with our previous model explanations, this demand is proportional to electricity consumption e. The inclusion of the emission/allowance component in the industrial electricity demand modifies industries' behaviour. EIIs' electricity consumption depends now on the power price, but also on the carbon cost. The interaction of these two effects (indirect and direct, respectively) is not always straightforward. From a modelling point of view, this new approach implies a slight change of the formulation of our models in Chapters 3 and 5. Considering the representation of the EIIs' surplus maximization, we need to subtract the CO_2 term from the original willingness to pay. This modification accounts for the fact that EIIs are willing to pay less for electricity because they are already paying something for CO_2. The CO_2 term therefore appears in the industries' surplus function. It accordingly appears in the complementarity conditions of the electricity demand function. Recall that p_{co_2} is the allowance price that exactly corresponds to the variable λ and e is the variable d_i^1 used in our models presented in Chapters 3 and 5. The new EIIs' surplus function in the EIINA and EIIA cases is as follows. Without loss of generality, we take the ETS_ISAC model as example[1].

- **ETS_ISAC_EIINA**

$$\mathbf{Max} \quad 8760 \cdot \int_0^{d_i^1} P_i^1(\epsilon) \cdot d\epsilon - 8760 \cdot p^1 \cdot d_i^1 - 8760 \cdot \lambda \cdot (\frac{\beta}{\alpha}) \cdot d_i^1 \qquad \forall i \tag{6.9}$$

The corresponding complementarity condition is:

$$0 \leq p_i + \lambda \cdot (\frac{\beta}{\alpha}) - a_i^1 + b_i^1 \cdot d_i^1 \cdot \perp d_i^1 \geq 0 \qquad \forall\ i \tag{6.10}$$

- **ETS_ISAC_EIIA**

$$\mathbf{Max} \quad 8760 \cdot \int_0^{d_i^1} P_i^1(\epsilon) \cdot d\epsilon - 8760 \cdot p^1 \cdot d_i^1 - 8760 \cdot \lambda \cdot (\frac{\beta - \gamma}{\alpha}) \cdot d_i^1 \qquad \forall i \tag{6.11}$$

The corresponding complementarity condition is:

$$0 \leq p_i + \lambda \cdot (\frac{\beta - \gamma}{\alpha}) - a_i^1 + b_i^1 \cdot d_i^1 \cdot \perp d_i^1 \geq 0 \qquad \forall\ i \tag{6.12}$$

We introduce similar modifications in all other models. Note that emission ($\frac{\beta}{\alpha}$) and allowance ($\frac{\beta-\gamma}{\alpha}$) factors are computed following the procedure described in Section 2.1.4 of Chapter 2. Input data are reported in Section 2.1.4. The emission factor ($\frac{\beta}{\alpha}$) is determined by dividing the verified industrial emission in 2005 (see Table 2.11) by EIIs' annual reference demand (obtained multiplying by 8760 the values in Table 2.5). Emission factors differ by country but they are identical in the two ETS phases (2005-2007) and (2008-2012) modelled here. Allowance factors, instead, account also for the NAPs allocated to industries. They are reported in Tables 2.9 and 2.10 respectively for the (2005-2007) and (2008-2012) ETS commitment periods. From the industries' emission in 2005 we subtract the amount of their NAPs in the two periods and we then divide the values obtained by the EIIs' annual electricity demand. This is the methodology adopted to define the allowance factors. Note that in period (2005-2007) all allowance factors are negative since industries were long on the emission market (see Table 2.12). By imposing a more stringent cap in (2008-2012), at least in Germany and in France, they become positive, even though are close to zero (see Table 2.13).

In this new context, industries assume an active role in the emission market. For this reason, we also change the formulation of the carbon constraint in order to account for industrial emissions. EIIs' emissions are simply computed by multiplying the industrial emission factors[2] in Tables 2.12

[1] For sake of generality, we consider the single average cost case under investments. Note that this formulation also holds with the assumption of fixed capacity. In the nodal average cost based models (with and without new capacities), it is sufficient to replace p^1 with p_i^1; while in the reference scenarios, one has to take into account the period segmentation.

[2] Note that these are identical in the two ETS phases considered.

and 2.13 by the industrial endogenous demand of power (recall that emissions are proportional to electricity consumption). This implies also a modification of the cap of the emission market. In particular, we state it at 790 Mio ton p.a. in the first ETS commitment period (2005-2007); while in the second commitment period it falls to about 710 Mio ton p.a. Considering again the ETS_ISAC as our reference scenarios, the new emission constraint in the EIINA and in the EIIA scenarios is:

- **ETS_ISAC_EIINA and ETS_ISAC_EIIA**

$$CAP - (\sum_{f,i,m} em_m \cdot gpc^1_{f,i,m} \cdot 8760 + \sum_{f,i,m} em_m \cdot gpi^1_{f,i,m} \cdot 8760 + \tag{6.13}$$

$$+ \sum_{t,f,i,m} em_m \cdot gpc^{t,2}_{f,i,m} \cdot hour^t + \sum_{t,f,i,m} em_m \cdot gpi^{t,2}_{f,i,m} \cdot hour^t +$$

$$+ \sum_i d^1_i \cdot (\frac{\beta}{\alpha}) \cdot 8760) \geq 0 \quad (\lambda)$$

The modelling of the direct ETS burden implies only the modifications of the emission constraint and industrial pricing system. The N-EIIs' problem remains unchanged in all models in Chapters 3 and 5 do not change. For this reason, we avoid to describe them again and the reader should refer to the explanations given in those Chapters.

The electricity demand function approach allows us to simultaneously evaluate the direct and indirect impacts of the EU-ETS on energy intensive industries. We fully acknowledge that it is just an approximation of the system, but, in order to make our analysis more realistic, we would need more detailed information on the industrial sectors.

6.3 Analysis of the Results

This Section is devoted to the presentation of the main results of these new models. In Chapters 3 and 5 we conducted a partial analysis since we considered only the indirect ETS impact on EIIs, namely the increased electricity price. We first examined this aspect since it represents the EIIs' main complaint.

Here we complete our study considering also the direct carbon impact on EIIs. Tables 6.1 and 6.4 summarize the global hourly electricity consumption of EIIs respectively under the scenarios without and with investments. In each table we distinguish the case where we model the sole indirect effect (as discussed in Chapters 3, 4 and 5) and the case where we have both the direct and indirect effects. As expected, the comparison of the industrial electricity demand before and after the implementation of the carbon regulation shows that the EU-ETS direct and indirect burdens negatively affects EIIs in all scenarios. Moreover, as we will see in Table 6.4, there is also a case where the problem is not feasible. This happen in the nodal average cost investment model without free allowances. This infeasibility is caused both by the non-convexity introduced by the average cost model and the absence of free allowances. Relatives changes of industrial demand depend on the pricing policies considered. These results are extensively explained in Appendix 6.5.

Moreover, parallel to what we did in Chapters 4 and 5, we run all these new models by considering an alternative starting point for the algorithm. Apart from the aforementioned model with infeasibility problems, all the others still have solutions. This is the other possible outcome of non-convexity. Even though these alternative solutions are different from those described in this Chapter, we do not report them. We just want to highlight that in addition to infeasibility, non-convexity may also lead to disjoint solutions as it happens in our cases.

EIINA Scenarios under Fixed Capacity Assumptions

In order to understand the different EIIs' reactions to the direct and indirect ETS burdens, we compare the EIIs' power demand in different scenarios. We first compare the ETS_SAC_EIINA and the ETS_NAC_EIINA cases with respect to the ETS_R_EIINA. The corresponding industrial demand is reported in Tables 6.1. We observe that the ETS_SAC_EIINA does not accommodate industries which globally reduce their electricity consumption by 2% with regard to the ETS_R_EIINA scenario. In contrast, industries increase their electricity consumption by 1% when they conclude average power contracts with local generators.

IMPACTS on EIIs			
	Indirect	**Indirect and Direct**	
		EIINA	**EIIA**
NETS_R	68,294		
ETS_R	60,613	63,409	64,073
ETS_SAC	63,408	62,351	64,562
ETS_NAC	64,543	64,262	66,233

Table 6.1: EIIs' Electricity Demand under Different Fixed Capacity Scenarios in MWh

Note that these relative changes result from combination of the variations of industrial demand in each node. For instance, in the ETS_SAC_EIINA model industries located in France and in the Belgian node Gramme reduce their electricity consumption respectively by 17% and 6% with respect to their ETS_R_EIINA levels. These significant cuts are not compensated by the EIIs' demand increases in the other nodes and the final outcome is the aforementioned 2% drop of their global demand.

In the ETS_NAC_EIINA model, one faces exactly the opposite situation. In fact, in France and in Belgium, industries raise their power consumption (respectively by +6% in France, +19% in Merchtem and +22% in Gramme) with respect their reference demand in ETS_R_EIINA. In Germany and in the Netherlands, their demand falls. In absolute values, the overall increase is higher than the global cut and this explains the final positive effect. These outcomes are in line with the results described in the previous Chapters.

In order to quantify the effect of the direct ETS impact on EIIs' electricity consumption, we compare the values reported in the second and the third columns of Table 6.1. The comparison is conducted case by case. It means ETS_R with ETS_R_EIINA, ETS_SAC with ETS_SAC_EIINA and ETS_NAC with ETS_NAC_EIINA. This analysis shows that the ETS direct burdens negatively affect industries both in the ETS_SAC_EIINA and ETS_NAC_EIINA models. This does not happen in the reference ETS_R_EIINA case where EIIs are able to increase their electricity consumption with respect to the ETS_R model. This results from the combination of several effects that are extensively described in Appendix 6.5.

Welfare Analysis of the EIINA Scenarios under Fixed Capacity Assumptions

The welfare analysis reported in Table 6.2 summarizes the results of the EIINA scenarios under the assumption of fixed capacity. We compare the case without environmental regulation (NETS_R) with the reference (ETS_R_EIINA), the single (ETS_SAC_EIINA) and the nodal (ETS_NAC_EIINA) models accounting both for the direct and indirect impacts of the EU-ETS. Note that the results of the NETS_R scenario are identical to those in Chapter 4.

EIINA				
Billion €	**NETS_R**	**ETS_R**	**ETS_SAC**	**ETS_NAC**
EIIs	15.53	14.79	14.57	15.77
Allowances (EIIs)		*1.43*	*3.32*	*3.36*
N-EIIs	130.87	130.53	129.84	128.21
Consumers	**146.40**	**145.32**	**144.41**	**143.98**
Generators	**25.22**	**26.10**	**26.14**	**27.26**
Allowances		*1.56*	*3.71*	*3.63*
TSO	**0.65**	**0.60**	**0.98**	**0.67**
Welfare	**172.27**	**172.02**	**171.53**	**171.91**

Table 6.2: Welfare Analysis of the EIINA Models under Different Fixed Capacity Scenarios

Consumers' surplus and generators' profits are determined without accounting for their emission trading on the carbon market. In fact, to compute the social welfare it does not matter who sells and who buys allowances because their values sum to zero. However, at lines "Allowances (EIIs)" and "Allowances" we show the allowance costs faced respectively by EIIs and generators in the case where free allowances are not distributed. These vary in correspondence with the allowance endogenous price of the different scenarios (for the numerical values see Appendix 6.5).

Note that in the EIINA models, we assume that EIIs do not receive any free allowance and then they effective surplus results from the combination of the value indicated at lines "EIIs" and "Allowances (EIIs)" of Table 6.2. The generators' profits are calculated as if allowances were fully grandfathered. Note that, under this assumption, generators' profits in the ETS scenarios are always higher than in the NETS_R case. This represents the so-called phenomenon of "windfall profits". The situation immediately changes when allowances are totally auctioned. Generator' profits become lower than in the NETS_R model. This outcome can be easily checked by subtracting the values at line "Allowances" from the corresponding generators' profits ("Generators"). Note that this approach allows us to evaluate the impacts of different free allocation proportions on generators' profits.

Both the EU-ETS and the application of average cost contracts damage N-EIIs as indicated by their decreasing surplus. This holds also in all other scenarios studied (see below).

Finally, we account also for the TSO's merchandising profits that accrue from the regulation of the transmission system.

EIIA Scenarios under Fixed Capacity Assumptions

The comparison of the EIIs' electricity demand in the EIINA and in the EIIA scenarios of Table 6.1 shows that, in all cases, the allocation of free allowances relieves EIIs. Considering only the the EIIA models, we notice that both the ETS_SAC_EIIA and the ETS_NAC_EIIA partially accommodate industries which consume more than in the ETS_R_EIIA case[3]. Again, nodal average cost contracts perform better. Note that the allocation of free allowances does not modify the overall emission target that remains unchanged.

Welfare Analysis of the EIIA Scenarios under Fixed Capacity Assumptions

Table 6.3 reports the results of the welfare analysis conducted by assuming that energy intensive industries are subsidized by free allowances and generators dispose of fixed capacity. Again, we show separately the values of the allowances that EIIs are supposed to freely receive and generators should pay in case of full auction.

EIIA				
Billion €	**NETS_R**	**ETS_R**	**ETS_SAC**	**ETS_NAC**
EIIs	15.53	13.34	10.58	12.11
Allowances (EIIs)		*0.39*	*1.53*	*1.41*
N-EIIs	130.87	128.71	123.40	118.23
Consumers	**146.40**	**142.05**	**133.98**	**130.34**
Generators	**25.22**	**29.31**	**35.66**	**40.72**
Allowances		*3.18*	*1.13*	*11.20*
TSO	**0.65**	**0.66**	**1.36**	**0.24**
Welfare	**172.27**	**172.02**	**171.00**	**171.30**

Table 6.3: Welfare Analysis of the EIIA Models under Different Fixed Capacity Scenarios

In fact, under the assumptions of the EIIA scenario, the term "Allowances (EIIs)" indicates the value of the allowances that are givem to EIIs proportionally to their electricity consumption. This has to be added to their surplus reported at line "EIIs" in Table 6.3.

The approach adopted to determine generators' profits is identical to that described in the previous welfare analysis. We assume that allowances are totally grandfathered and we then report their value separately. Note that in the ETS_R_EIIA generators' profit are higher than in the reference case without ETS (NETS_R) even after the subtraction of the allowance costs. This means that generators' profits depend on both the electricity price (indirect ETS impact) and the allowance allocation method (direct ETS impact). A similar situation occurs also in the ETS_NAC_EIIA case. In contrast, generators lose in the single average cost scenario.

N-EIIs are still negatively affected both by the environmental policy and the introduction of average cost power contracts.

EIINA Scenarios under Investment Assumptions

Table 6.4 reports the results of the EIINA and EIIA models under investment assumptions. In both groups of models, generators invest in renewable and nuclear power plants (see Appendix 6.5 for more details).

[3]The single and the nodal average contracts help them to recover respectively the 12% and 51% of their lost consumption. These percentages are obtained by comparing the EIIs' demand values in the ETS_SAC_EIIA and ETS_NAC_EIIA with the industrial consumption in the NETS_R case (68,294 MWh).

IMPACTS on EIIs			
	Indirect	Direct and Indirect	
		EIINA	EIIA
NETS_IR	80,628		
ETS_IR	67,388	59,044	65,563
ETS_ISAC	65,641	56,159	66,185
ETS_INAC	69,758	**Infeasible**	66,730

Table 6.4: EIIs' Electricity Demand under Different Investment Scenarios in MWh

We still compare the second and the third columns of Table 6.4 to quantify the impact of the direct ETS burdens on EIIs. This comparison reveals that industrial consumption decreases when we account for the cost of emission allowances. This holds both under the ETS_IR_EIINA and in the ETS_ISAC_EIINA scenarios. Moreover, the ETS_INAC_EIINA model is not feasible. Infeasibility problems come from the non-convexity generated by average cost prices[4] and from the absence of free allowances[5].

Welfare Analysis of the EIINA Scenarios under Investment Assumptions

Due to the infeasibility of the ETS_NAC_EIINA case, we compare only the NETS_IR, ETS_IR and the ETS_SAC scenarios. Table 6.5 lists the surpluses/profits of the different players of the market. In this case, the results of the NETS_IR model correspond exactly to those described in Chapter 5.

EIINA			
Billion €	**NETS_IR**	**ETS_IR**	**ETS_ISAC**
EIIs	20.18	15.58	13.85
Allowances (EIIs)		*4.18*	*4.71*
N-EIIs	136.97	133.88	133.20
Consumers	**157.15**	**153.64**	**151.76**
Generators	**15.79**	**21.23**	**22.87**
Allowances		*4.47*	*5.30*
TSO	**0.52**	**0.84**	**0.92**
Welfare	**173.46**	**175.70**	**175.55**

Table 6.5: Welfare Analysis of the EIINA Models under Different Investment Scenarios

The terms "Allowances (EIIs)" and "Allowances" still indicate the cost of the allowances that EIIs and generators should buy in the case of full auctioning. Their values are comparatively lower than those in the fixed capacity scenarios, since with investments allowances become cheaper (see Appendix 6.5).

Both with and without the allocation of free allowances, generators' profits in the ETS_IR_EIINA

[4]See Chapter 3 for more details.

[5]Feasibility is reached by progressively reducing the emission factor of the carbon component of industrial price.

and in the ETS_ISAC_EIINA cases are higher than in the NETS_IR model. The explanations given in the previous welfare analyses still hold.

Finally, N-EIIs' surplus decrease with the implementation of the environmental policy, even though this negative impact is partially mitigated by investments.

EIIA Scenarios under Investment Assumptions

In the EIIA scenario, free allowances allow industries to increase their electricity demand with respect to EIINA models as indicated in Table 6.4. The ETS_INAC_EIIA case leads to the highest industrial consumption level among the EIIA cases, even though it is still lower than in the ETS_INAC model. Moreover, the outcome of the ETS_ISAC_EIIA and the ETS_INAC_EIIA cases are quite similar.

Welfare Analysis of the EIIA Scenarios under Investment Assumptions

Table 6.6 reports the results of all feasible cases of the EIIA scenario. EIIs' global surplus still results from the combination of the results of the "EIIs" and "Allowance (EIIs)" rows of Table 6.6. In this case the values of the allowances that EIIs receive for free are quite low. This is due to the more restrictive environmental policy characterizing our investment scenarios.

N-EIIs are negatively impacted by these policies but again investments partially relieve their situation.

EIIA				
Billion €	**NETS_IR**	**ETS_IR**	**ETS_ISAC**	**ETS_INAC**
EIIs	20.18	13.97	12.54	14.00
Allowances (EIIs)		0.05	0.17	0.15
N-EIIs	136.97	131.78	130.84	131.43
Consumers	**157.15**	**145.76**	**143.38**	**145.45**
Generators	**15.79**	**24.43**	**25.24**	**24.43**
Allowances		*7.99*	*8.90*	*8.89*
TSO	**0.52**	**1.08**	**1.22**	**1.10**
Welfare	**173.46**	**171.26**	**169.84**	**170.97**

Table 6.6: Welfare Analysis of the EIIA Models under Different Investment Scenarios

Under all the ETS scenarios, generators increase their profits with respect to the NETS_IR case. These are windfall profits and result from grandfathering allowances. Moreover, both in the ETS_IR and in the ETS_ISAC scenarios, profits maintain this tendency even they are reduced by the allowance costs reported at line "Allowance" in Table 6.6.

EIINA and EIIA Scenarios under Nuclear Power Investment Assumptions

In our network, nuclear investments are allowed only in France. In order to evaluate the effects of the application of a nuclear power policy on the European electricity market, we consider an additional case where generators may invest in nuclear power in all countries of our models.

IMPACTS on EIIs			
	Indirect	Direct and Indirect	
		EIINA	EIIA
NETS_IR	90,075		
ETS_IR	90,075	88,747	90,272
ETS_ISAC	88,718	87,210	88,921
ETS_INAC	89,193	87,667	89,344

Table 6.7: EIIs' Electricity Demand under Different Nuclear Power Investment Scenarios in MWh

We apply this assumption to all investment models studied. The outcome is really positive: generators build new nuclear power plants in any node and both N-EIIs and EIIs increase their electricity consumption. Table 6.7 reports the global electricity demand of EIIs under this new investment assumption. Investments in nuclear power capacity induce generators to abandon part of the existing lignite and coal plants and reduce emissions. In particular, in all reference cases the emission constraint is not binding and the allowance price becomes equal to zero and the emission market disappear. This means that the implementation of a nuclear policy may solve all the EIIs' problems caused by the EU-ETS. This reasoning is also supported by our results (see Table 6.7). In the NETS_R and ETS_R scenarios, energy intensive industries require an identical amount of electricity[6]. In this context, the application of average cost based contracts makes no sense and, in fact, it leads to a reduction of industrial electricity consumption in all models. Nuclear policy would be the real solution to the environmental problem, even though we fully acknowledge that it is not easy to implement.

6.4 Conclusions

In this last Chapter, we simultaneously analyze the direct and the indirect ETS impact on energy intensive industries. Due to the lack of information on the industrial production problem, we use their demand function to study their reactions to the environmental policy. Industrial electricity demand now depends on two factors represented respectively by the electricity price and the carbon component. We implement both the cases where industries receive and do not receive free allowances. We find that the combination of the increased electricity cost and the carbon direct contribution leads to a reduction of industrial electricity consumption. As expected, the EIIA class of models performs better than the EIINA. It is an obvious consequence of the free allowances allocated to industries. Moreover, in accordance with the results of the previous Chapters, average cost based contracts partially mitigate the ETS negative effects on industries.

Under fixed capacity assumptions, nodal average cost based contracts seem to be more effective. They globally address both the direct and indirect ETS burdens on energy intensive industries, even though these local contracts do not allow EIIs to fully recover the lost of their demand caused by the EU-ETS. Results in Table 6.4 show that, in spite of the investment policy, industries do to not benefit too much from the application of the long-term contracts. It could be useful looking for alternative solutions.

A more detailed analysis reveals that the industrial reactions to the application of average cost

[6]Since the emission constraint is not binding, carbon opportunity cost does not affect their prices. Unchanged prices imply identical consumption levels.

power contracts vary on a node by node basis.

For all these reasons, the implementation of a nuclear policy would be a suitable solution for all these problems since it could curb emissions without any additional carbon cost. However, we know that this is a rather impossible achievable target.

6.5 Appendix: Results

This Appendix is devoted to a deeper description of the results shown in this Chapter. It is subdivided into two parts that are respectively dedicated to the results of the models with fixed capacity and investments.

6.5.1 Results of the Model under Fixed Capacity Assumptions

We follow the usual approach by first introducing the results of the reference case and then analyzing the impact of the application of single and nodal average cost contracts. We consider the relative changes of consumers' prices and demand both in the EIINA and EIIA versions of the models.

Results of the ETS_R_EIINA Model

We start our analysis by comparing the results of the ETS_R_EIINA scenario with those of the ETS_R model presented in Chapter 4. Table 6.8 reports the electricity prices ("EP") of the ETS_R_EIINA case paid by both consumer groups in summer and in winter . By construction, industries pay also a carbon component ("CC") that added to the "EP" gives the final prices "FP" listed in the last two columns of Table 6.8. These represent the actual costs faced by industries in summer and in winter. The carbon component is simply computed by multiplying the allowance price that, in this case, amounts to 3.95 €/ton (see Table 6.10) by the emission factor reported in Table 2.12 in Chapter 2. In this new context, N-EIIs globally increase their summer power demand by 2% (see Table 6.12) with respect to the corresponding level of the ETS_R case. An identical reasoning holds also for EIIs which raise their electricity consumption by 5%, even though they face an additional carbon cost imposed by the direct ETS impact. This positive effect is a direct consequence of the low allowance price (see below). In summer, the price at the hub is determined by coal technologies. This includes also the coal emission costs[7].

In contrast, the winter electricity price is set by oil-based plants that are more expensive than CCGT, which are the power stations at the margin in the ETS_R scenario. This has a negative effect on N-EIIs whose demand in winter globally falls by 0.7% with respect to the ETS_R case (see Table 6.13). Recall that, by construction, EIIs have a constant electricity demand over year. The positive effect of decreasing power prices in summer compensates for their increase in winter. It results that in the ETS_R_EIINA the average (weighted by period duration and accounting for the carbon component) of EIIs' final prices ("FP") of the two periods is lower than the average (weighted by period duration) of their electricity prices in ETS_R. This induces industries to increase their hourly consumption of electricity with respect to the ETS_R level[8]. Finally, since there is no congestion,

[7]Recall that the fuel cost of a coal technology is 21.62 €/MWh. In this specific case the emission costs is 3.77 €/MWh. In sum, fuel and emission costs amount to 25.39 €/MWh which is exactly the German summer electricity price (see Table 6.8).

[8]Note that the increased industrial electricity demand in association with a low allowance price induces power companies to exploit oil-based plants in winter.

ETS_R_EIINA					
	N-EIIs		**EIIs**		
	EP Summer	**EP Winter**	**CC**	**FP Summer**	**FP Winter**
Germany	25.39	50.23	*2.73*	**28.11**	**52.96**
France	4.50	50.23	*2.49*	**6.99**	**52.72**
Merchtem	38.06	50.23	*2.61*	**40.66**	**52.84**
Gramme	16.82	50.23	*2.61*	**19.43**	**52.84**
Krimpen	38.06	50.23	*2.09*	**40.15**	**52.33**
Maastricht	38.06	50.23	*2.09*	**40.15**	**52.33**
Zwolle	34.42	50.23	*2.09*	**36.51**	**52.33**

Table 6.8: N-EIIs and EIIs' Electricity Prices in the ETS_R_EIINA scenario in €/MWh

winter electricity prices ('EP") are identical in all nodes (see Table 6.8). This is in line with the results of the ETS_R model.

	ETS_R	**ETS_R_EIINA**	**ETS_R_EIIA**
Germany	25,095	29,259	28,756
France	24,910	23,227	23,883
Merchtem	3,538	3,579	3,702
Gramme	1,963	2,030	2,074
Krimpen	2,603	2,674	2,857
Maastricht	889	913	976
Zwolle	1,615	1,727	1,825
Total	**60,613**	**63,409**	**64,073**

Table 6.9: EIIs' Electricity Demand under Different ETS_R Scenarios in MWh

Last, the allowance price is so cheap because the emission constraint is less binding. This depends on the new assumptions on which this model is based. In fact, we modify the structure of the carbon market by increasing the cap to account also for the EIIs' emissions. Note that during the pilot EU-ETS phase, industries were long on the emission market due to an over-allocation of allowances. Our model re-produces this possibly excessive of allowances and translates it into a low carbon price (3.95 €/ton).

	ETS_R	**ETS_R_EIINA**	**ETS_R_EIIA**
Allowance Price	24.44	3.95	8.00

Table 6.10: Allowance Prices under Different ETS_R Scenarios in €/ton

Results of the ETS_R_EIIA Model

Energy intensive industries further improve their situation in the ETS_R_EIIA model. In this case, we assume that they receive free allowances to cover part of their ETS costs. Specifically, the allocation of free allowances lead to negative carbon components "CC" (see Table 6.11) that add to the marginal electricity prices and relieve industries[9]. This results in a global decrease of their final prices "FP" (see Table 6.11) followed by an increase of their electricity consumption both with respect to the ETS_R (+6%) and the ETS_R_EIIA (+1%) cases. Recall that carbon components are computed by

ETS_R_EIIA					
	N-EIIs		EIIs		
	EP Summer	**EP Winter**	**CC**	**FP Summer**	**FP Winter**
Germany	29.25	53.65	*-0.24*	**29.01**	**53.41**
France	4.50	53.65	*-0.64*	**3.86**	**53.01**
Merchtem	39.81	53.65	*-1.12*	**38.69**	**52.53**
Gramme	18.94	53.65	*-1.12*	**17.82**	**52.53**
Krimpen	39.81	53.65	*-2.80*	**37.01**	**50.85**
Maastricht	39.81	53.65	*-2.80*	**37.01**	**50.85**
Zwolle	36.72	53.65	*-2.80*	**33.92**	**50.85**

Table 6.11: N-EIIs and EIIs' Electricity Prices in the ETS_R_EIIA scenario in €/MWh

multiplying the so-called allowance factor ($\frac{\beta-\gamma}{\alpha}$) whose values are reported in Table 2.12 of Chapter 2 by the allowance price in Table 6.9. In this particular case, allowance factors are negative since, as already said, industries were long in the period under analysis (2005-2007). Moreover, the unitary cost of a CO_2 allowance (8 €/ton) is twice than in the ETS_R_EIINA model, but still lower than in ETS_R case. Note that its increase is parallel to the increased EIIs' demand.

Summer			
	ETS_R	**ETS_R_EIINA**	**ETS_R_EIIA**
Germany	18,746	19,673	19,490
France	22,097	22,127	22,127
Merchtem	1,287	1,316	1,311
Gramme	577	592	589
Krimpen	2,899	2,964	2,951
Maastricht	691	706	703
Zwolle	1,151	1,185	1,179
Total	**47,449**	**48,565**	**48,350**

Table 6.12: N-EIIs' Summer Electricity Demand under Different ETS_R Scenarios in MWh

Like in the ETS_R_EIINA, also in the ETS_R_EIIA model coal and oil-based technologies set power prices in summer and in winter taking into account their emission (opportunity) costs. Due to the different CO_2 allowance cost, N-EIIs' electricity prices in the ETS_R_EIIA case are higher than in ETS_R_EIINA (see Tables 6.8 and 6.11). This holds in both periods and induce N-EIIs to decrease their consumption (see Tables 6.12 and 6.13). Their demand's relative changes are respectively of -0.4% in summer and -0.9% in winter. The ETS_R_EIIA perform is a mixed way with respect to ETS_R: N-EIIs' consumption increases by 2% in summer and decreases by 2% in winter[10].

[9]We recall again that, in these fixed capacity scenarios, the carbon market accounts for the ETS period (2005-2007) where an excessive amount of free allowances was distributed to EIIs. For this reason, our carbon components "CC" are negative and the EIIs' final prices "FP" are lower than the "EP" prices paid by N-EIIs. In the ETS_R_EIINA, industries faces a reverse situation.

[10]As already said, in the ETS_R, winter price are set by fuel and emission costs of CCGT. Instead, in the ETS_R_EIIA

Winter			
	ETS_R	**ETS_R_EIINA**	**ETS_R_EIIA**
Germany	47,936	47,586	47,168
France	44,538	44,212	43,824
Merchtem	4,496	4,463	4,424
Gramme	1,924	1,910	1,893
Krimpen	7,332	7,278	7,214
Maastricht	1,777	1,764	1,748
Zwolle	2,977	2,955	2,929
Total	**110,979**	**110,168**	**109,201**

Table 6.13: N-EIIs' Winter Electricity Demand under Different ETS_R Scenarios in MWh

Results of the ETS_SAC_EIINA Model

In this Subsection, we present the results of the single average cost contracts under the EIINA and EIIA assumptions. We start by considering the single average cost based models. Table 6.14 compares the single average cost price ("SACP") in three different ETS_SAC scenarios. The single average cost price includes the average production and transmission costs that EIIs pay respectively to generators and the TSO. In addition, now EIIs face the direct ETS costs, represented by the carbon component. The contribution of these carbon components varies by country and influences final electricity prices "FP" that are reported in Table 6.15.

Single Average Cost Prices (SACP)			
	ETS_SAC	**ETS_SAC_EIINA**	**ETS_SAC_EIIA**
Fuel	10.64	10.58	10.93
Transmission	2.74	1.99	2.66
Emission	7.32	3.22	9.24
Capacity	17.39	16.92	17.04
Average Cost Price	**38.10**	**32.71**	**39.87**

Table 6.14: Single Average Cost Price under Different ETS_SAC Scenarios in €/MWh

One observes that the single average cost price in the ETS_SAC_EIINA case is comparatively low in the with respect to the other prices in Table 6.14. Adding the respective carbon components, one obtains values that in Germany, in France and in Belgium are higher than 38.10 €/MWh, the single average cost price faced by industries in the ETS_SAC model (see Table 6.15). In the Netherlands, instead, the application of a single average cost policy mitigates industrial consumers even when they do not receive subsidies. However, the negative effects prevails, which globally results in a fall of 2% of the EIIs' electricity demand with respect to the ETS_SAC (see Table 6.17).

Carbon components are still computed as the product of industrial emission factors ($\frac{\beta}{\alpha}$) whose values are in Table 2.12 of Chapter 2 and allowance price that in the ETS_SAC_EIINA case amounts to 9.33 €/ton (see Table 6.16). As already observed, the lenient environmental policy characterizing the EIINA scenario explains this quite low allowance price. In fact, the high NAPs granted to EIIs make the emission constraint less restrictive.

case, winter prices are determined by oil, that is more expensive than CCGT both in terms of fuel and emissions.

FP (SACP + CC)		
	ETS_SAC_EIINA	**ETS_SAC_EIIA**
Germany	39.15	39.02
France	38.59	37.59
Merchtem	38.87	35.89
Gramme	38.87	35.89
Krimpen	37.65	29.92
Maastricht	37.65	29.92
Zwolle	37.65	29.92

Table 6.15: Final Price Paid by EIIs under the ETS_SAC_EIIAN and ETS_SAC_EIIA Scenarios in €/MWh

	ETS_SAC	**ETS_SAC_EIINA**	**ETS_SAC_EIIA**
Allowance Price	28.48	9.33	28.44

Table 6.16: Allowance Prices under different ETS_SAC Scenarios in €/ton

This low allowance price has a positive effect on N-EIIs which increase their electricity consumption with respect to the ETS_SAC case (see Tables 6.18 and 6.19). In fact, power companies adopt an identical technology mix to supply N-EIIs in the ETS_SAC and the ETS_SAC_EIINA scenarios. In both cases, coal plants fix the marginal price in summer; while old gas and oil-based technologies play this role in winter. The allowance price determines the difference between the two pricing groups. Since allowances are less expensive in the ETS_SAC_EIINA than in the ETS_SAC case, electricity prices are lower and N-EIIs are encouraged to consume more. This holds in both periods and demand increases are respectively 2.2% in summer and 2.1% in winter (see Tables 6.18 and 6.19).

Results of the ETS_SAC_EIIA Model

The implementation of the single average cost pricing system together with the granting of free allowances relieves EIIs everywhere (see Table 6.17).

	ETS_SAC	**ETS_SAC_EIINA**	**ETS_SAC_EIIA**
Germany	31,065	30,286	30,382
France	19,408	19,180	19,640
Merchtem	4,511	4,428	4,748
Gramme	1,939	1,903	2,041
Krimpen	3,319	3,354	3,966
Maastricht	1,133	1,145	1,355
Zwolle	2,033	2,055	2,430
Total	**63,408**	**62,351**	**64,562**

Table 6.17: EIIs' Demand under different ETS_SAC Scenarios in MWh

Considering the values reported in Table 6.14, one can observe that the single average cost price ("SACP") in the EIIA model is higher than in the other ETS_SAC scenarios. However, by adding the carbon components (that in this specific case are negative) we get the final price "FP" listed in the third column of Table 6.15. This final values are all lower than the corresponding single average price and EIIs increase their power consumption by 3.5% and 1.9% in comparison with the ETS_SAC_EIINA and the ETS_SAC cases respectively (see Table 6.17).

Summer			
	ETS_SAC	**ETS_SAC_EIINA**	**ETS_SAC_EIIA**
Germany	18,564	19,430	18,565
France	22,127	22,127	22,127
Merchtem	1,281	1,309	1,280
Gramme	574	589	574
Krimpen	2,885	2,947	2,885
Maastricht	688	702	688
Zwolle	1,144	1,176	1,144
Total	**47,263**	**48,280**	**47,262**

Table 6.18: N-EIIs' Summer Demand under Different ETS_SAC Scenarios in MWh

Winter			
	ETS_SAC	**ETS_SAC_EIINA**	**ETS_SAC_EIIA**
Germany	46,190	47,132	45,647
France	44,376	45,314	44,378
Merchtem	4,118	4,198	3,994
Gramme	1,826	1,863	1,795
Krimpen	6,857	6,992	6,702
Maastricht	1,675	1,708	1,642
Zwolle	2,815	2,872	2,763
Total	**107,857**	**110,079**	**106,920**

Table 6.19: N-EIIs' Winter Demand under Different ETS_SAC Scenarios in MWh

Recall that the factors used to compute the carbon components are those of Table 2.12, but the allowance price in the ETS_SAC_EIIA is 28.44 €/ton (see Table 6.16). The carbon price is slightly lower than in the ETS_SAC, but three times higher than in ETS_SAC_EIINA. This influences N-EIIs' marginal electricity prices and consequently their consumption. The fuel and the emission costs of coal and old gas and oil-based power plants still determine N-EIIs' power prices respectively in summer and in winter. The comparison between ETS_SAC_EIINA and ETS_SAC_EIIA shows that, due to the increased allowance price, N-EIIs reduce the amount of electricity consumed with respect to the ETS_SAC_EIINA model both in summer (-2%) and in winter (-3%). N-EIIs' summer electricity consumption is similar in the ETS_SAC_EIIA and in the ETS_SAC cases; while in winter is lower in the ETS_SAC_EIIA (see Tables 6.18 and 6.19). This results from the combination of the nodal demand effects.

Comparison between ETS_NAC_EIINA and ETS_NAC_EIIA and ETS_SAC_EIINA and ETS_SAC_EIIA Models

Parallel to our results in Chapter 4, nodal average cost prices perform better than single average cost prices. The comparison between the EIIs' global consumption levels in the two average cost cases confirms this phenomenon (see Tables 6.22 and 6.17). In the the ETS_NAC_EIINA, industrial demand is 3% higher than in the ETS_SAC_EIINA. The same results applies to the EIIA case where nodal average cost contracts allow industries to increase their global demand of electricity by 2.6% with respect to the single average cost case. However, a node by node analysis points out that this positive tendency mainly depends on the industrial consumption in France and in the Belgian node Gramme. In fact, in all other locations the implementation of the ETS_NAC_EIINA contracts leads to a net decrease in industrial demand. As already observed in Chapter 4, the increases of EIIs' power consumption in France and in Gramme are so significant that they suffice to recover the losses of all the remaining consumers in the other locations. This holds both in the EIINA and in the EIIA versions of the ETS_NAC model[11].

Nodal Average Cost Prices (NACP)			
	ETS_NAC	**ETS_NAC_EIINA**	**ETS_NAC_EIIA**
Germany	43.70	35.15	44.67
France	17.39	21.19	23.07
Merchtem	59.79	34.46	42.78
Gramme	23.79	20.31	25.17
Krimpen	53.25	41.94	56.62
Maastricht	57.06	56.41	60.91
Zwolle	57.06	49.62	60.49

Table 6.20: Nodal Average Cost Prices under Different ETS_NAC Scenarios in €/MWh

Results of the ETS_NAC_EIINA and the ETS_NAC_EIIA Models

The comparison among ETS_NAC models (see Table 6.22) highlights that industries achieve the highest consumption level in the ETS_NAC_EIIA[12] while the lowest in the ETS_NAC_EIINA scenarios. This reflects the tendency already encountered in the single average cost pricing model (see Table 6.17). This can be explained by using identical reasonings.

FP (NACP + CC)		
	ETS_NAC_EIINA	**ETS_NAC_EIIA**
Germany	41.46	43.82
France	26.95	20.81
Merchtem	40.50	38.83
Gramme	26.34	21.22
Krimpen	46.78	46.75
Maastricht	61.26	51.03
Zwolle	54.47	50.58

Table 6.21: Final Price Paid by EIIs under Different ETS_NAC Scenarios in €/MWh

[11]The French industries' demand increases by 28% and 40% with respect to the corresponding level in the ETS_SAC_EIINA and ETS_SAC_EIIA models. In Gramme, an identical comparison shows increases of 30% and 33% respectively.

[12]Relative changes are of +3.07% and +2.62% with respect to the ETS_NAC_EIINA and the ETS_NAC models.

Table 6.20 reports the nodal average cost prices in the three ETS_NAC cases, but EIIs' electricity consumption is driven by the final price "FP" listed in Table 6.21. As already explained, these "FP" are given by adding the positive (EIINA) and the negative (EIIA) carbon components to the respective nodal average cost prices of Table 6.20. As usual, carbon components are computed by multiplying the emission/allowance factors in Table 2.12 of Chapter 2 by the respective allowance prices in Table 6.23. Note that in the ETS_NAC and in the ETS_NAC_EIIA models, CO_2 allowance prices are identical.

	ETS_NAC	**ETS_NAC_EIINA**	**ETS_NAC_EIIA**
Germany	26,913	28,576	26,821
France	29,002	24,573	27,415
Merchtem	2,176	4,253	4,432
Gramme	2,601	2,483	2,720
Krimpen	2,119	2,631	2,633
Maastricht	620	507	784
Zwolle	1,113	1,239	1,427
Total	**64,543**	**64,262**	**66,233**

Table 6.22: EIIs' Electricity Demand under Different ETS_NAC Scenarios in MWh

In the ETS_NAC_EIINA case, the direct ETS effect negatively affects French industries in all scenarios. Specifically, in the ETS_NAC_EIINA and in the ETS_NAC_EIIA, French EIIs reduce their electricity consumption respectively by 15% and by 5% in comparison with their ETS_NAC level. This demand reductions depend on the capacity split. In fact, in the ETS_NAC French industries are only supplied by nuclear power plants whose average cost amounts to 17.39 €/MWh as indicated in Table 6.20. By modelling the ETS direct impact, generators change the approach used to share the existing capacity among consumers. Both in the ETS_NAC_EIINA and the ETS_NAC_EIIA scenarios, French industries receive a proportion of hydro, renewable and nuclear technologies and, moreover, in the ETS_NAC_EIIA case they are also supplied by a small amount of lignite and coal plants. The different cost structure of these technologies affects final nodal average cost prices paid by French EIIs by making them more expensive. However, between the single and the nodal average cost pricing system, French industries would still prefer the application of nodal average contracts. Finally, the split of capacity also explains the relative changes of industrial demand in all other nodes.

	ETS_NAC	**ETS_NAC_EIINA**	**ETS_NAC_EIIA**
Allowance Price	28.21	9.14	28.21

Table 6.23: Allowance Prices under different ETS_NAC Scenarios in €/ton

N-EIIs' electricity consumption is influenced by marginal prices. Note that, in the ETS_NAC_EIIA and in the ETS_NAC models N-EIIs' summer prices [13] are identical and this leads to identical consumption levels in any node (see Table 6.24). This does not holds in winter where N-EIIs' demand in ETS_NAC_EIIA is 1% lower than in ETS_NAC.

N-EIIs reach their highest benefit in terms of consume under the ETS_NAC_EIINA scenario. In fact, they raise their electricity demand both in summer (+7%) and in winter (+0.7%) with respect to

[13] Both in the ETS_NAC_EIIA and ETS_NAC cases, coal is at the margin during the summer and moreover, allowance prices are equal (see Table 6.23). This results in identical electricity prices. Moreover, the network is not congested and prices amount to 48.54 €/MWh everywhere.

Summer			
	ETS_NAC	**ETS_NAC_EIINA**	**ETS_NAC_EIIA**
Germany	18,575	19,438	18,575
France	19,889	22,127	19,889
Merchtem	1,282	1,309	1,282
Gramme	548	577	548
Krimpen	2,887	2,948	2,887
Maastricht	688	712	688
Zwolle	1,144	1,182	1,144
Total	**45,014**	**48,293**	**45,014**

Table 6.24: N-EIIs' Summer Electricity Demand under Different ETS_NAC Scenarios in MWh

the ETS_NAC model (see Tables 6.24 and 6.25). The quite low allowance price (9.14 €/ton) explains again these two effects[14].

Winter			
	ETS_NAC	**ETS_NAC_EIINA**	**ETS_NAC_EIIA**
Germany	47,175	47,051	46,738
France	42,903	43,715	42,485
Merchtem	4,374	4,413	4,124
Gramme	1,870	1,888	1,811
Krimpen	7,154	7,196	6,950
Maastricht	1,734	1,744	1,707
Zwolle	2,912	2,922	2,867
Total	**108,121**	**108,929**	**106,681**

Table 6.25: N-EIIs' Winter Electricity Demand under Different ETS_NAC Scenarios in MWh

The implementation of these additional models confirms the results of the previous Chapters. Nodal average cost based contracts seem to be the most effective between the two average cost policies. These local contracts globally address both the direct and indirect ETS burdens on energy intensive industries, even though they do not allow EIIs to fully recover their lost demand. Moreover, a more detailed analysis shows that the industries' reactions to the application of average cost based contracts vary on a node by node basis.

6.5.2 Results of the Investment Models

In this Section, we present the results of the EIINA and the EIIA scenarios under investment assumptions. We first discuss the new outcomes of the reference investment scenarios and then we evaluate the impact of long-term contracts on EIIs. Since we want to model an investment scenario, we consider the second stage (2008-2012) of the first EU-ETS commitment period. For this reason,

[14]Coal plants are at the margin both in the ETS_NAC_EIINA and in the ETS_NAC cases and set EIIs' summer electricity prices. However, in the in ETS_NAC_EIINA the carbon price is lower and this defines lower electricity prices. In winter, the global relative change is less consistent. Note that, in the ETS_NAC, CCGT defines the price; while in the ETS_NAC_EIINA oil-based plants play this role. However, since allowances are less expensive in the ETS_NAC_EIINA case, we have lower power prices as outcome.

we set a tighter emission cap to account for the reduced NAPs of the power and the industrial sectors (see Table 2.10). The total cap now amounts to about 710 Mio. ton p.a. Finally, we also modify the allowance factors adopted in the computation of the carbon components in the EIIA scenario in accordance with this new ETS assumption (see Table 2.13).

Investment Effects in the ETS_IR_EIINA and in the ETS_IR_EIIA Models

As already observed, the combination of the ETS direct and indirect costs has a negative effect on EIIs which react by reducing their electricity consumptions with respect to the ETS_IR level. These cuts are about of 12% and 3% respectively in the ETS_IR_EIINA and in the ETS_IR_EIIA models. The surprising result is that EIIs' demand in these investment scenarios is even lower than in the corresponding cases with fixed capacity (compare Tables 6.28 and 6.9). This implies that investments in new power capacity do not help EIIs to mitigate the incentive to relocate their production activities outside of European markets. Moreover, our results highlight that granting free allowances does not completely solve the problem and alternative solutions should be found (see Table 6.28).

	ETS_IR	**ETS_IR_EIINA**	**ETS_IR_EIIA**
Investment	29,242	14,921	30,338

Table 6.26: Investments under Different ETS_IR Scenarios in MW

Table 6.26 reports global investments in the different ETS_IR scenarios. In the ETS_IR_EIINA model, power companies reduce their investment level by 49% with respect to the ETS_IR, since they need less capacities to supply industrial consumers. Moreover, because of a relative cheap allowance price (see Table 6.29), generators prefer to exploit already existing coal plants. In the ETS_IR_EIIA scenario, the quite high allowance (see Table 6.29) price induces generators to increment investments in clean technologies and abandon coal based plants. This has a positive impact on investment that in this scenario totally amounts to 30,338 MW, 4% more than in the ETS_IR model.

Finally, both in the ETS_IR_EIINA and in the ETS_IR_EIIA cases, investments account for new nuclear plants in France and renewable technologies in Merchtem.

Results of the ETS_IR_EIINA Model

Table 6.27 reports the periodical electricity prices ("PE") and the final prices ("FP") paid respectively by N-EIIS and EIIs in the EIINA scenario. The final prices faced by EIIs are obtained by the sum of the carbon components ("CC") and the electricity prices ("PE"). Power prices are determined by coal and CCGT plants which are the marginal technologies at the hub respectively in summer and in winter. This holds both in the ETS_IR and in the ETS_IR_EIINA scenarios. The difference between the two groups of prices is again determined by the allowance price (see Table 6.29). Parallel to the cases with fixed capacity, allowances are cheaper in the ETS_IR_EIINA than in the ETS_IR and this encourages N-EIIs to require more energy[15] both in summer (+0.7%) and in winter (+0.4%).

As already said, in the ETS_IR_EIINA scenario, EIIs reduce their electricity consumption by 12% with respect to the ETS_IR model. This is mainly caused by the inclusion of the carbon components that in average increase their final price. The fall of EIIs' electricity demand has a direct impact both on allowance price and investments (see Table 6.29 and 6.26 respectively).

[15] Compare Tables 6.31 and 6.32.

ETS_IR_EIINA					
	N-EIIs		**EIIs**		
	EP Summer	**EP Winter**	**CC**	**FP Summer**	**FP Winter**
Germany	33.50	41.85	*8.59*	**42.09**	**50.44**
France	4.50	35.66	*7.84*	**12.34**	**43.50**
Merchtem	39.54	45.31	*8.22*	**47.76**	**53.53**
Gramme	19.43	41.73	*8.22*	**27.65**	**49.94**
Krimpen	41.73	43.67	*6.60*	**48.33**	**50.27**
Maastricht	41.73	42.96	*6.60*	**48.33**	**49.55**
Zwolle	39.25	42.90	*6.60*	**45.85**	**49.50**

Table 6.27: N-EIIs and EIIs's Electricity Prices under Different ETS_IR_EIINA Scenario in €/MWh

	ETS_IR	**ETS_IR_EIINA**	**ETS_IR_EIIA**
Germany	27,907	25,014	25,676
France	27,754	24,122	27,445
Merchtem	4,054	3,160	4,250
Gramme	2,224	1,907	2,300
Krimpen	2,750	2,432	2,940
Maastricht	956	840	1,056
Zwolle	1,742	1,569	1,896
Total	**67,388**	**59,044**	**65,563**

Table 6.28: EIIs' Electricity Demand under Different ETS_IR Scenarios in MWh

	ETS_IR	**ETS_IR_EIINA**	**ETS_IR_EIIA**
Allowance Price	19.21	12.45	22.26

Table 6.29: Allowance Prices under Different ETS_IR Scenarios in €/ton

Since industries are active on the emission market, we increase the global cap. The quite high (electricity and carbon) costs faced induce EIIs to decrease their power demand. This makes the emission constraint less binding[16] and allowance price becomes cheaper than in the ETS_IR case[17]. For this reason, generators continue to exploit coal based technologies and are not encouraged to invest.

In contrast, N-EIIs benefit from the application of this pricing policy. This is mainly due to the values of the allowance prices in the ETS_IR and in the ETS_IR_EIINA cases. In fact, in both these reference investment scenarios, the marginal fuel and emission costs of coal and CCGT plants define N-EIIs' electricity prices respectively in summer and in winter. However, the allowance price in the ETS_IR_EIINA scenario is lower than in the ETS_IR case. Consequently their prices becomes cheaper and N-EIIs raise their electricity demand by 0.73% and 0.38% respectively in summer and in winter.

Results of the ETS_IR_EIIA Model

The situation partially changes in the ETS_IR_EIIA case where industries receive free allowances. Globally EIIs increase their electricity demand by 11% with respect to the ETS_IR_EIINA, but it is still 3% lower than in the ETS_IR model.

ETS_IR_EIIA					
	N-EIIs		**EIIs**		
	EP Summer	**EP Winter**	**CC**	**FP Summer**	**FP Winter**
Germany	42.87	46.09	*0.89*	**43.76**	**46.98**
France	4.50	35.66	*0.67*	**5.17**	**36.33**
Merchtem	39.08	45.97	*-2.00*	**37.08**	**43.97**
Gramme	20.60	43.98	*-2.00*	**18.60**	**41.98**
Krimpen	45.97	51.36	*-5.79*	**40.18**	**45.58**
Maastricht	45.97	47.51	*-5.79*	**40.18**	**41.72**
Zwolle	44.82	48.60	*-5.79*	**39.04**	**42.81**

Table 6.30: N-EIIs and EIIs' Electricity Prices under Different ETS_IR_EIIA Scenario in €/MWh

Table 6.30 reports respectively N-EIIs and EIIs' power and final prices in the ETS_IR_EIIA scenario. Note that the impacts of the carbon components differ per country. These are positive[18] in Germany and in France and negative in Belgium and in the Netherlands. Consequently, they increase German and French EIIs' electricity prices ("PE") and reduce those of the Belgian and the Dutch industries leading to the final EIIs' prices ("FP") reported in Table 6.30. Our assumptions on the environmental policy of the period (2008-2012) explain these different carbon effects. In fact, we suppose that in the (2008-2012) period national NAPs are more restrictive than in the first phase (2005-2007). This results in the allowance factors ($\frac{\beta-\gamma}{\alpha}$) indicated in Table 2.13 of Chapter 2 that we use to compute the carbon components.

[16]Note that under the ETS_IR the global annual demand (EIIs plus N-EIIs) amounts to 1,224 TWh against the 1,174 TWh in the ETS_IR_EIINA model.

[17]There is a double correspondence between allowance price and EIIs' demand. Allowance price affects industrial electricity consumption since it appears in the computation of both power prices and carbon components. On the other side, EII's electricity demand determines their emissions and indirectly the market allowance price.

[18]Even though less 1 €/MWh.

Summer			
	ETS_IR	**ETS_IR_EIINA**	**ETS_IR_EIIA**
Germany	18,983	19,289	18,844
France	22,127	22,127	22,127
Merchtem	1,310	1,311	1,313
Gramme	587	589	587
Krimpen	2,916	2,937	2,906
Maastricht	695	700	693
Zwolle	1,160	1,171	1,155
Total	**47,777**	**48,124**	**47,624**

Table 6.31: N-EIIs' Summer Electricity Demand under Different ETS_IR Scenarios in MWh

In the ETS_IR_EIIA case, the allowance price is the highest among the scenarios in Table 6.29. This has a positive effect because it induces generators to invest in clean technologies and abandon coal; but it also contributes to increase electricity price[19] ("PE"). This damages N-EIIs which decrease their electricity consumption with respect to the other reference investment scenario[20] (see Tables 6.31 and 6.32).

Winter			
	ETS_IR	**ETS_IR_EIINA**	**ETS_IR_EIIA**
Germany	48,253	48,610	48,092
France	45,866	45,866	45,866
Merchtem	4,526	4,519	4,512
Gramme	1,945	1,952	1,940
Krimpen	7,359	7,400	7,257
Maastricht	1,789	1,797	1,776
Zwolle	2,994	3,011	2,968
Total	**112,731**	**113,154**	**112,410**

Table 6.32: N-EIIs' Winter Electricity Demand under Different ETS_IR Scenarios in MWh

Results of the ETS_ISAC_EIINA Model

Table 6.34 and 6.35 report respectively the single average cost prices and the final price faced by EIIs in the ETS_ISAC_EIINA and the ETS_ISAC_EIIA scenarios. The results depict a situation that is quite similar to that described in the corresponding cases with fixed capacity. Apart from the electricity price reported in Table 6.34, EIIs also face the cost of buying allowance on the ETS market. These additional costs added to the single average cost price results in the prices listed in Table 6.35. EIIs' electricity consumption is then affected by these values. Since they are comparatively higher than the single average cost price in the ETS_ISAC model, industries globally reduce their power demand by 14% (see Table 6.33).

[19] Like in the other reference investment cases, coal and CCGT plants define N-EIIs' electricity prices. This are higher because of the more expensive allowance price.

[20] N-EIIs' demand falls are 0.3% (ETS_IR) and 1% (ETS_IR_EIINA) in summer and 0.3% (ETS_IR) and 0.7% (ETS_IR_EIINA) in winter.

	ETS_ISAC	ETS_ISAC_EIINA	ETS_ISAC_EIIA
Germany	32,159	27,102	31,562
France	20,091	17,341	19,833
Merchtem	4,670	3,983	4,930
Gramme	2,007	1,712	2,119
Krimpen	3,435	3,082	3,961
Maastricht	1,173	1,053	1,353
Zwolle	2,105	1,888	2,427
Total	**65,641**	**56,159**	**66,185**

Table 6.33: EIIs' Electricity Demand under Different ETS_ISAC Scenarios in MWh

Single Average Cost Prices (SACP)			
	ETS_ISAC	**ETS_ISAC_EIINA**	**ETS_ISAC_EIIA**
Fuel	7.49	7.90	6.47
Transmission	5.28	3.78	5.34
Emission	5.68	3.78	4.63
Capacity	18.17	17.84	20.00
Average Cost Price	**36.62**	**33.30**	**36.44**

Table 6.34: Single Average Cost Price under Different ETS_ISAC Scenarios in €/MWh

FP (SACP + CC)		
	ETS_ISAC_EIINA	**ETS_ISAC_EIIA**
Germany	43.45	37.43
France	42.57	37.18
Merchtem	43.01	34.21
Gramme	43.01	34.21
Krimpen	41.10	29.99
Maastricht	41.10	29.99
Zwolle	41.10	29.99

Table 6.35: Final Price Paid by EIIs under the EII_ISAC_EIINA and the EII_ISAC_EIIA in €/MWh

The significant cut of EIIs' demand in the ETS_SAC_EIINA case makes the emission constraint less binding. This results in an allowance price of 14.71 €/ton (see Table 6.36). According to our assumptions, the allowance price affects N-EIIs' electricity demand and prices. In this particular case, the quite low allowance price reduces the contribution of the emission charges in marginal power prices of N-EIIs. This allows them to increase their electricity demand by about 1% both in summer and in winter with respect to their consumption level in the ETS_ISAC case (see Table 6.39 and 6.40)[21].

	ETS_ISAC	ETS_ISAC_EIINA	ETS_ISAC_EIIA
Allowance Price	24.80	14.71	24.80

Table 6.36: Allowance Prices under Different ETS_ISAC Scenarios in €/ton

The reduced demand of electricity affects also the investment level. In the ETS_ISAC_EIINA model, the new available capacity totally amounts to 8,927 MW, of which almost the 60% goes to industries. This is much less than in the ETS_ISAC (-66%). Nevertheless, generators do not change their investment choices and still build nuclear power plants in France and renewable technologies in Merchtem.

	ETS_ISAC	ETS_ISAC_EIINA	ETS_ISAC_EIIA
EIIs	17,400	5,220	19,703

Table 6.37: Investments for EIIs under Different ETS_ISAC Scenarios in MW

	ETS_ISAC	ETS_ISAC_EIINA	ETS_ISAC_EIIA
N-EIIs	8,796	3,708	9,842

Table 6.38: Investments for N-EIIs under Different ETS_ISAC Scenarios in MW

Results of the ETS_ISAC_EIIA Model

An opposite situation is described in the ETS_ISAC_EIIA. In fact, free allowances relieve industries' cost balance and raises their benefit. This is highlighted by the global increment of electricity consumption with respect to the ETS_ISAC_EIINA (+18%) and ETS_ISAC (+0.8%) models (see Table 6.33). These increases are particularly significant in Belgium and in the Netherlands where carbon components ("CC") reduce the industrial final prices ("FP") as indicated in Tables 6.34 and 6.35. This induces Belgian and Dutch EIIs to consume more electricity than in the other ETS_ISAC scenarios.

Contrarily, in France and in Germany, this new policy does not allow EIIs to fully recover their consumption level in the ETS_ISAC[22].

On the other side, N-EIIs are able to maintain an almost identical consumption level both in summer and in winter with respect to the ETS_ISAC (see Tables 6.39 and 6.40). This because coal

[21] Note that both in the ETS_ISAC and the ETS_ISAC_EIINA models, coal and CCGT plants define N-EIIs' electricity prices in summer and in winter respectively. Considering the marginal cost pricing approach, a lower allowance price reduce also electricity price if fuel charges do not change.

[22] As already explained in ETS_IR_EIIA, carbon components reduce electricity prices of Belgian and Dutch EIIs while increase those of German and French industries. These different impacts depend on the more restrictive environmental regulation applied in the (2008-2012) period (see Chapter 2 for more explanations).

Summer			
	ETS_ISAC	**ETS_ISAC_EIINA**	**ETS_ISAC_EIIA**
Germany	18,729	19,186	18,729
France	22,127	22,127	22,127
Merchtem	1,316	1,324	1,316
Gramme	588	593	588
Krimpen	2,898	2,930	2,898
Maastricht	691	698	691
Zwolle	1,151	1,167	1,151
Total	**47,498**	**48,026**	**47,498**

Table 6.39: N-EIIs' Summer Electricity Demand under Different ETS_ISAC Scenarios in MWh

and CCGT plants still fix N-EIIs' summer and winter prices and allowance cost (24.80 €/ton) is identical in the ETS_ISAC and in the ETS_ISAC_EIIA models.

Winter			
	ETS_ISAC	**ETS_ISAC_EIINA**	**ETS_ISAC_EIIA**
Germany	47,958	48,490	47,958
France	45,866	45,866	45,866
Merchtem	4,499	4,456	4,499
Gramme	1,934	1,947	1,925
Krimpen	7,032	7,310	7,014
Maastricht	1,751	1,774	1,748
Zwolle	2,915	2,982	2,910
Total	**111,955**	**112,824**	**111,920**

Table 6.40: N-EIIs' Winter Electricity Demand under Different ETS_INAC Scenarios in MWh

Finally, investments in new capacity totally amount to 29,195 MW. Again, power companies dedicate the largest amount of these new capacities to industries and choose France to installed new nuclear units, while new renewable technologies are built in Merchtem and in Germany (see Tables 6.37 and 6.38).

Results of the ETS_NAC_EIIA Model

The application of the nodal average cost pricing system does not help industries to mitigate the additional burdens caused by the ETS. The model without subsidies, i.e. the ETS_INAC_EIINA case, does not have feasible solutions. It becomes feasible by progressively reducing the contribution of the carbon component. This is simply obtained decreasing the emission factor reported in Table 2.13 in Chapter 2. We do not report the results obtained. Note that the infeasibility is a direct consequence of the average process used to determine prices of EIIs that makes the model non-convex.

The ETS_INAC_EIIA version of the problem has instead a solution. Even receiving subsidies, EIIs are not able to recover their lost demand and moreover their global consumption is 4% lower than in the ETS_INAC case (see Table 6.42). This cut is again driven by the German and French industries which reduce their power demand respectively by 12% and 2% in comparison with their ETS_INAC level. As already explained in the other EIIA models, this is a direct consequence of the

EIIs				
	ETS_INAC	**ETS_INAC_EIIA**	**CC**	**FP**
Germany	41.05	44.70	0.99	45.69
France	17.39	17.70	0.74	18.44
Merchtem	33.18	32.59	-2.23	30.36
Gramme	23.06	22.44	-2.23	20.21
Krimpen	48.78	53.50	-6.44	47.06
Maastricht	59.27	59.99	-6.44	53.56
Zwolle	55.83	58.72	-6.44	52.28

Table 6.41: N-EIIs' Hourly Winter Electricity Demand under Different ETS_ISAC Scenarios in MWh

environmental policy adopted in the period (2008-2012). Results in Table 6.41 may help to undertsnad nodal consumption changes. In the second and third columns, we report the nodal average cost prices respectively in the ETS_INAC and in the ETS_INAC_EIIA models. The carbon component ("CC") is reported in the fourth column; while in the last one we indicate the final price ("FP") faced by EIIs. These account for both the energy price and the carbon components. These carbon components are pure costs in Germany and in France; while in Belgium and in the Netherlands they contribute to relieve industries.

	ETS_INAC	**ETS_INAC_EIIA**
Germany	28,875	25,437
France	29,002	28,513
Merchtem	5,040	5,344
Gramme	2,635	2,767
Krimpen	2,473	2,608
Maastricht	561	715
Zwolle	1,173	1,345
Total	**69,758**	**66,730**

Table 6.42: EIIs' Electricity Demand under Different ETS_INAC Scenarios in MWh

	ETS_INAC	**ETS_INAC_EIIA**
Allowance Price	19.26	24.76

Table 6.43: Allowance Prices under Different ETS_INAC Scenarios in €/ton

In this context, the allowance price is 24.76 €/ton: 29% higher than in the ETS_INAC (see Table 6.43). This means that the emission constraint is much more tight than in the ETS_INAC where the market electricity demand is even 2% higher than in the ETS_INAN_EIIA. Moreover, such allowance price incentives investments in clean technologies, namely nuclear and renewable. Totally, the new available capacity is 32,957 MW. In spite of the reduction of global electricity demand (see below), investment in the ETS_NAC_EIIA case are 3% higher than in the ETS_INAC model. New nuclear and renewable plants are introduced to replace a small proportion of coal technologies.

Finally, the increased allowance price has a negative impact on N-EIIs which face higher price[23].

[23] Again, coal and CCGT defines their periodical prices both in the ETS_INAC and in the ETS_INAC_EIIA. The

Consequently their consumption falls by 0.6% and 0.4% in summer and in winter respectively (see Tables 6.46 and 6.47).

	ETS_INAC	ETS_INAC_EIIA
EIIs	2.458	31,333

Table 6.44: Investments for EIIs under Different ETS_INAC Scenarios in MW

	ETS_INAC	ETS_INAC_EIIA
N-EIIs	29,533	1,624

Table 6.45: Investments for N-EIIs under Different ETS_INAC Scenarios in MW

Summer		
	ETS_INAC	**ETS_INAC_EIIA**
Germany	18,980	18,731
France	22,127	22,127
Merchtem	1,310	1,316
Gramme	574	574
Krimpen	2,916	2,898
Maastricht	705	702
Zwolle	1,165	1,157
Total	**47,777**	**47,504**

Table 6.46: N-EIIs' Summer Electricity Demand under Different ETS_INAC Scenarios in MWh

Generally, the EIIA class of models performs better than the EIINA group. It is a direct consequence of the free allowances distributed to EIIs. These results are in line with those of the scenarios with fixed capacity. Among the EIIA models, the nodal average cost price leads to the highest industrial electricity consumption even though this is not sufficient to fully recover the industrial lost demand. Comparing the EIIs' nodal electricity consumption in the EIIA scenarios, we can see that French and Belgian EIIs would prefer buy electricity at the nodal average cost price. In the other nodes, the single average cost pricing system would be the preferable solution.

difference between the two models is represented by allowance price.

Winter		
	ETS_INAC	**ETS_INAC_EIIA**
Germany	48,250	47,960
France	45,866	45,866
Merchtem	4,527	4,499
Gramme	1,937	1,925
Krimpen	7,373	7,326
Maastricht	1,789	1,778
Zwolle	2,997	2,978
Total	**112,738**	**112,333**

Table 6.47: N-EIIs' Winter Electricity Demand under Different ETS_INAC Scenarios in MWh

Chapter 7

Conclusion

The inception of the EU-ETS has introduced direct and indirect carbon costs that create economic distortions and negatively affect energy intensive industries' competitiveness on international market. This would result in a possible relocation of industrial production activities towards countries with less restrictive environmental policies and induce the so-called carbon leakage effect.

This thesis can be seen as an attempt to study this phenomenon. Our aim consists in finding a possible solution to EIIs' problem. Taking into account a proposal of French industries, we analyze the application of average cost power contracts to a market where the power sector is described on a technological basis while energy intensive industries are aggregated in one sector and their reaction to the EU-ETS impacts is simply quantified by their demand function.

We illustrate that these contracts indeed partially relieve the ETS direct and indirect costs and mitigate the incentive to relocate activities but with quite different impacts in accordance with the average cost policy applied and the national technological structure. Moreover, the EU-ETS drives investments and induces power companies to modify their fuel mix by replacing dirty with clean technologies. Either a restrictive carbon cap or a high allowance price can be adequate tools to achieve this goal.

Finally, the potential of a representation by technology of the power sector is that it enables us to study simultaneously the direct and the indirect EU-ETS impacts on energy intensive industries and the rest of the market.

Nevertheless, due to the novelty of the subject treated, this thesis can be considered as a starting point for further and future research projects. Many other hypotheses can be explored and several variants of the models presented can be investigated.

First, working with a single demand function for energy intensive industries is not sufficient. It may be possible to consider several scenarios with different elasticity values of their electricity demand. In this way, elasticity would become a random variable and consequently the problem would be stochastic. Introducing stochasticity in an equilibrium problem would be a worthwhile exercise since this is a quite unexplored field.

Secondly, one could also apply the models developed in this thesis to a sector by sector analysis by accounting for the sectorial economic peculiarities and the different contributions that the direct and the indirect ETS burdens have on each sector (as explained in Chapter 1).

Lastly, results suggest that the models describe two extreme cases. It could be interesting to study some intermediate and alternative models. An easy extension would be the combination of a single production cost with nodal average transmission prices. Other more complex scenarios could be taken into account.

Moreover, many other aspects of the EU-ETS deserve to be explored. European Commission is currently reviewing the EU-ETS Directive 2003/87/EC in order to improve the functioning of the carbon market and avoid economic distortions. Among the packages of the legislative proposals of the European Commission there is one dedicated to a new renewable policy. It imposes a mandatory target of 20% of renewable energy by 2020, including a 10% of biofuels. European Member States argue that this target, in addition to the required reduction of 20% of GHG, is too tight.
Considering this complex framework, it would be worthwhile to analyze how the implementation of this renewable policy and average cost power contracts will affect energy intensive industries.

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