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A two-sector model of the European Union Emissions Trading Scheme

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Abstract

As the largest greenhouse gas emissions trading scheme in the world, the European Union Emissions Trading Scheme (EU ETS) is a benchmark for carbon prices worldwide.

A price for carbon represents a cost for emissions-intensive activities under the EU ETS, which must be taken into account by constrained actors in their (emissions-generating) technology operation and investment decisions. A carbon price also represents an incentive for non-EU ETS actors who, through the international Kyoto credits market, are able to exploit emissions reductions generated from investments in lower-emitting technologies. It also indicates to the environmental authority the extent to which the environmental objective is taken into account by the polluter in his economic decisions. The European carbon price is therefore a crucial indicator for a wide cross-section of actors: EU ETS market participants, international emission reduction project developers and policy makers worldwide.

The subject of this paper is a model which has been developed to estimate EU-ETS constrained emissions and consequent EU ETS permit market equilibrium prices in the medium term. The model, in its current stage, is conceived for the case of a permit market composed of two EU27-aggregated sectors: electric and non-electric, and for the specific case of full banking and borrowing. The paper presents the conceptual approach of the model, its main features and quantitative relationships, together with the method of resolution under perfect foresight. It also highlights the role that the model fills with respect to other models currently being developed.

1 Introduction

1.1 The European Union Emissions Trading Scheme

The European Union Emissions Trading Scheme (EU ETS), created in 2003 (EC, 2003) and implemented in 2005, is the first international trading system for carbon dioxide (CO_2) emissions in the world. The EU ETS is a typical permit market, based on “cap and trade”[1] (refer to Figure 1). The “cap”, as set by the regulatory authority, represents the environmental goal or requisite global emissions level for all emission sources or installations[2] covered by the permit market over a given period of time, and thus determines the total number of emission permits to be issued. Operators of installations are then allowed to trade permits. The principle is that installations with lower abatement costs are incited to effect greater emissions reductions compared to those with higher abatement costs, due to the ability of the former to sell corresponding surplus permits to the latter, who find it less costly to buy these permits rather than abate. The resulting permit price (or EUA price for European Union Allowance price) depicts the confrontation between overall permit supply and total demand of EU ETS installations, taking into account marginal abatement costs of each installation (lines A, B in Figure 1).

[1] Another type of permit market is “baseline and credit”, wherein a producer can only generate emissions credits for trade on the permit market if s/he reduces his emissions *beyond* a set baseline level of emissions.
[2] “Installation” according to (EC, 2003) is a stationary technical unit where one or more activities listed in Annex I (of (EC, 2003), see Annex I of this document) are carried out, and any other directly associated activities which have a technical connection with the activities carried out on that site and which could have an effect on emissions and pollution

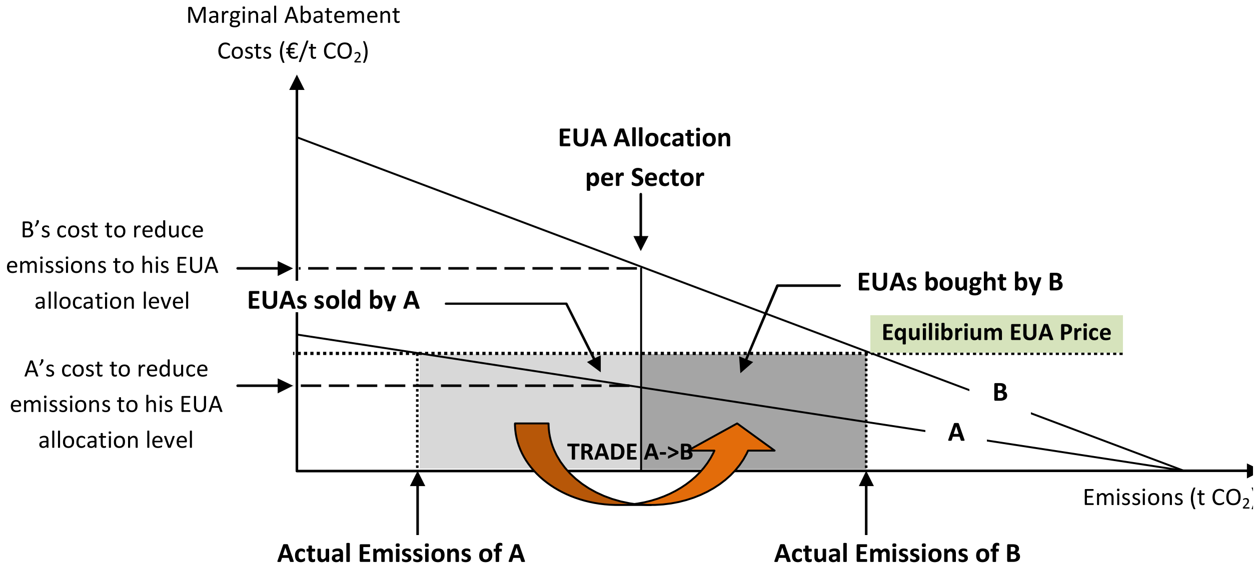


Figure 1: Theory behind the EU ETS cap and trade market for a given compliance period Consider that the market is composed of two installations, each allocated the same number of initial emission permits for a given compliance period. The combined allocation of the two installations is the global emissions cap (for simplicity the use of Kyoto credits (see Box 2) is not taken into account here). Equilibrium, assuming compliance, requires total emissions (installation A + installation B) to be equivalent to the global cap. Installation A has lower marginal abatement costs than installation B. It is advantageous for A to reduce its emissions beyond the level prescribed by its individual permit allocation, so as to sell them to B, which finds it more advantageous to buy the permits liberated from A, as long as they are at a price below its own marginal abatement cost. At equilibrium, the marginal abatement cost of the last unit of emissions reduction is the price at which EUAs are traded – the equilibrium EUA price – and the collective emissions of installations A and B is equivalent to the global cap.

The EU ETS covers CO_2 emissions from over 11, 000 energy-intensive installations across the EU27, representing roughly 50% of the EU's total CO_2 emissions. Installations covered by the scheme include combustion plants, oil refineries, coke ovens, iron and steel plants, production facilities for cement, glass, lime, brick, ceramics, pulp and paper; all over a certain capacity threshold. Annex 1 gives a list of the categories of activities and types of installations currently covered by the EU ETS.

Member States (MS) of the EU are required to set out, in National Allocation Plans (NAPs) the total quantity of emission allocations available in that MS, as well as the CO_2 emission allowances allocated to EU ETS obligated installations in their territory.

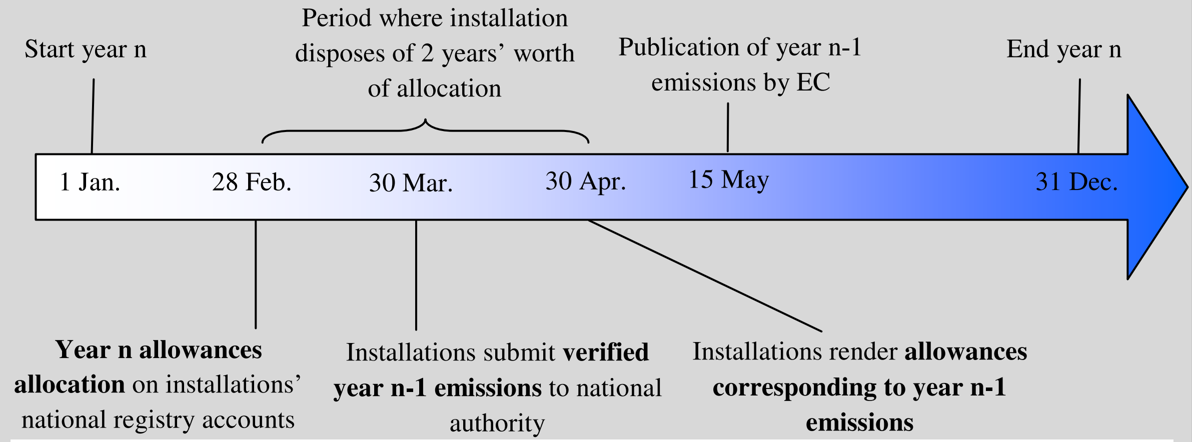
The EU ETS consists of three distinct trading periods, or Phases, covering the period 2005 to 2020: Phase I (trial Phase): 2005-2007, Phase II: 2008-2012[3] and Phase III: 2013-2020. Installations are required to demonstrate compliance at the end of each year. The scheme incorporates a number of flexibility mechanisms in line with the aim of minimising compliance costs, namely, banking and borrowing (refer to Box 1), and the linking of the EU ETS credits with so-called Kyoto credits (see Box 2)[4]. These flexibility mechanisms have the effect of potentially changing supply-demand dynamics.

The EU ETS was conceived with a view to its own evolution and extension in accordance with the evolving European economic and environmental context. Examples comprise the inclusion of additional categories of activities (e.g. aviation in 2012, aluminium in Phase III), additional gases (e.g. N_2O in Phase II, on a voluntary basis) and adaptation of operational modalities (a move towards auctioning as the main permit allocation method from 2013 onwards).

[3] This period corresponds to the Kyoto commitment period

[4] In the initial trial Phase (Phase I), banking as well as borrowing was limited to *within* the Phase, that is, no banking was allowed between the consecutive years covering the end of Phase I and the start of Phase II i.e. years 2007 and 2008.

Box 1: Banking and Borrowing in the EU ETS (Adapted from (De Perthuis, 2009))



In order to be compliant, installations must submit, by April 30th of year n, permits (or allowances) corresponding to their verified emissions for year n-1. Each installation receives, at the latest, Feb. 28th of year n, his allowances for year n. There is therefore a period of at least 2 months (1st Mar. – 30th Apr.) where the installation has at its disposal two years' worth of allowances allocation. The operator of the installation thus has, for this 2-month period, the flexibility to reallocate these allowances over the years n and n-1 in accordance with the installation's real emissions for year n-1, the price of allowances on the market in year n-1, and the operator's expectations regarding emissions and allowances prices/abatement costs for year n. An operator may choose to "borrow" emissions allowances, using some of year n allowance allocation for compliance in year n-1. An operator may also decide to "bank" emissions i.e. carry forward some of his year n-1 allowances allocation for possible use in year n, depending on his position (in particular if he is long), the price of permits in year n-1 (namely, if they are low), and expectations regarding emissions and abatement costs for year n (particularly, if relatively high).

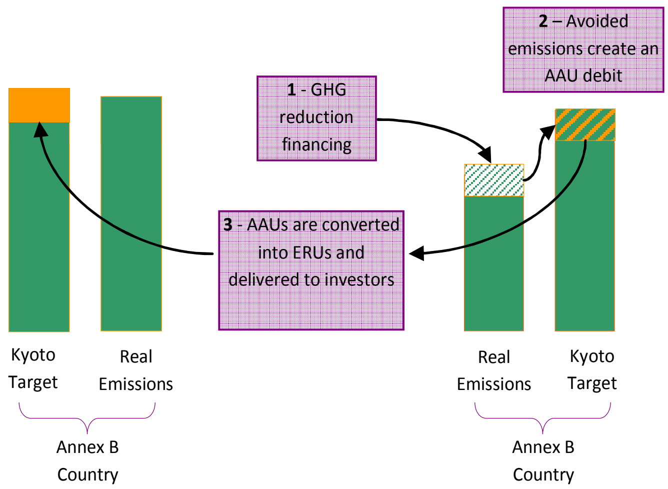
Borrowing is allowed for consecutive years within a given Phase (intra-Phase), but not between two adjacent Phases (inter-Phase). Through borrowing, therefore, installations may collectively pollute more than a given year's allowance allocation; but all cumulated borrowing must be settled at the end of the given Phase. Banking is allowed between any two consecutive years, whether entirely within a single Phase or spanning adjacent Phases.

Banking and borrowing effectively allow operators of installations to temporally reallocate emissions permits thus giving them a degree of flexibility in managing their emissions stream (abatement) through time, effecting any emissions reduction according to when they deem it to be least costly.

Box 2: Joint Implementation (JI) & Clean Development Mechanism (CDM) in EU ETS

With the linking of the EU ETS with "Kyoto" credits, EU ETS installations can, within certain limits, use credits from Clean Development Mechanism (CDM) and Joint Implementation (JI) projects to cover their emissions permit obligations under the trading system. Joint Implementation (JI) and Clean Development Mechanism (CDM) are the project-based flexibility mechanisms of the Kyoto Protocol. Through JI and CDM, public or private actors in industrialised countries can achieve part of their Kyoto reduction target by implementing emissions reduction projects abroad, counting the associated reductions towards their own commitment. JI applies to projects implemented in countries which also have Kyoto targets (countries in Annex B of the Kyoto Protocol, so-called "Annex B" countries), while CDM applies to projects in countries having no targets (developing countries or "non-Annex B" countries).

In the case of JI, the implementation of an emissions-reducing project gives rise to credits, called emission reduction units (ERU), which are added to the Kyoto allowances of the investing entity and simultaneously subtracted from those of the host entity, who is also subject to an emissions reduction obligation. If both entities are EU ETS entities, the effect on overall supply of EU ETS permits remains unchanged, and the EU ETS emissions cap remains intact.



In the case of the CDM, where the host entity is not subject to an emissions permit obligation, credits, or certified emission reductions (CER), generated from the implementation of an emissions-reducing project in a developing country and acquired by an EU ETS entity are additional to any allowances issued in line with the EU ETS-specified cap. The use of CDM therefore effectively results in an increase in the overall emission permit supply.

The use of JI and CDM credits is capped by the limits imposed by the EU Member States in their National Allocation Plans (NAPs). The majority of Kyoto credits used in the EU ETS are CDM credits (CER).

1.2 Existing models of emissions permit systems

Two main types of model are currently being developed to represent emission permits markets: econometric and optimisation models.

Econometric models derive a relationship between CO_2 market price and various price determinants, based on statistical analysis. A majority of econometric models are oriented towards the short-term dynamics of CO_2 prices, such as weather conditions or short-term energy prices, with a particular focus on carbon permits as financial assets. They are of particular relevance for investigating financial sector issues such as returns and price volatility. At the same time, with econometric models, a lot of the underlying information relevant to price formation is lost: the complexity of the EU ETS (or other permit market) structure and the CO_2 price formation process is reduced to statistical parameters. In addition, given the short-term focus, there is little or no explicit modelling of longer term factors, such as economic and technological contexts or institutional framework, all of which are fundamental to understand and analyse carbon price formation over longer time horizons which are more relevant to decision-makers in EU ETS sectors.

Optimisation models typically identify an (endogenous) optimal policy (in the specific case of ETS, an emissions (abatement) policy or strategy) in line with the minimisation of (abatement) costs over a period of time. The emissions-generating process is typically exogenously defined. The result is a trajectory describing the inter-temporal evolution of the permit price.

In the broader sphere of general or partial equilibrium energy-economic-emissions models, a common approach is to determine (endogenous) CO_2 emissions resulting at competitive equilibrium in market(s) (or entire economies) of emissions-producing goods, and, with the aid of (exogenous or endogenous) marginal CO_2 abatement cost curves, to determine the CO_2 price that would result under give emission reduction policy targets.

1.3 Similarities and differences of the proposed model to existing models

The proposed model is optimisation model, whose basis lies in the achievement of supply-demand equilibrium (compliance) at least cost[5]. It includes technological, economic and emissions representation for the electricity sector and, in this respect, follows the bottom-up approach for modelling this sector, as do, for example, the POLES model and the MARKAL family of models. A more top-down approach to modelling (emissions) of other (non-electricity) sectors is used, based on observed trends in economic activity and emissions intensities and on derived abatement coefficients. The top-down treatment of the non-electricity sector(s) is also used in well-known models such as POLES, EPPA and DICE/RICE models[6]. Unlike the aforementioned models, however, the perimeter of the proposed model is specifically limited to countries, sectors and installations covered by the EU ETS. Moreover, by specific representation of the institutional EU ETS framework the model enables the user to zoom in on the dynamics within this particular system. Finally, the proposed model is based in the medium term – ten to fifteen years – a time horizon not often focussed on in current energy-economic-emissions modelling exercises but which is entirely relevant for analysis of the EU ETS where we are dealing with Phases of 5 or 8 years and, for the moment, a time horizon up to 2020 (potentially 2030). The model thus bridges a gap between existing econometric modelling, which focus on the very short-term dynamics, typically day-to-day or seasonally, and current macroeconomic (top-down) and techno-economic (bottom-up) modelling, which typically treat a long-term time horizon of 30-50 years or more.

2 The Formal Model

The proposed model is an optimisation model based on compliance – the attainment of permit supply-demand equilibrium – at minimal cost. The following sections: describe the generalisations made in the specification of the model (Section 2.1); detail the main components determining permit supply and demand in the EU ETS (Sections 2.2 and 2.3);

[5] Only physical permit supply-demand is considered; speculation is assumed not to play a major role in supply-demand equilibrium

[6] It should be noted that in some of these models coupling of top-down with bottom-up techniques is also envisaged depending on the analyses to be conducted.

and, present the method of resolution of the model under perfect foresight for a given time period (Section 2.4).

2.1 Model Generalisations

The EU ETS covers installations, of a certain capacity and/or emissions level, in the sectors specified in Annex I of the EU ETS Directive (EC, 2003). Although the EU ETS applies at the level of each individual installation, for the purpose of the model, the market is considered as composed of EU27-aggregated sectors, rather than distinct installations. In the model, two sectors are represented: the electricity production sector – currently, the principal EU ETS sector, with roughly 50% of Phase I allocation (see Figure 2), and a relatively strict emissions cap[7] – and "all other sectors", collectively grouped into what is hereafter referred to as the non-electricity sector. The electricity sector is represented at the technology level, thus installations of a given technology type are grouped together and are assumed to have identical attributes in terms of for example fuel type, efficiency, availability. The non-electricity sector is represented at a more aggregate level, with an average or aggregated parameter used to encompass all EU ETS-relevant attributes of the individual installations (and sub-sectors) which comprise it. Thus, marginal abatement costs for the ensemble of installations within the sector are represented by an aggregated sectoral marginal abatement cost function; installation-level emissions factors by an average sectoral emissions factor; individual production levels by a total sectoral production level etc. Underlying all of this is the assumption that installations of a given sector are likely to be affected by the same external economic and technological factors dictating their production and emissions, and that they all have access to the same abatement opportunities and use of flexibility mechanisms.

[7] The stricter cap of the electricity sector is driven primarily by the fact that, compared to the other industrial sectors, the electricity sector is less affected by international competition and has the possibility to pass on the costs of carbon prices to end-consumers

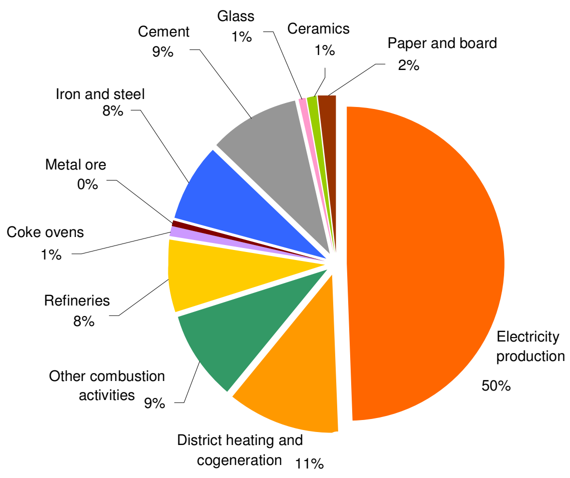


Figure 2: Sectoral shares in Phase I EUA allocation

(*Source*: CITL, taken from (Trotignon & Delbosc, 2008))

The model is constructed to represent the EU ETS from the start of the Kyoto commitment period; the initial trial Phase is therefore not modelled[8].

2.2 Permit supply

Permit supply is composed, in the first instance, of allowances (EUA) accorded to the sector under the national allocation plans (NAPs) of the 27 EU Member States (MS). Thus, for a given (EU27-level) sector, i, composed of k_i installations, with annual initial allocation $s_{k_i,t}$, EUA supply[9] in any given year is given by:

$$EUA_{i,t} = \sum_{MS} \sum_{k_i} s_{k_i,t}$$

With an overall annual initial allocation given by:

$$EUA_t = \sum_{i} \sum_{MS} \sum_{k_i} s_{k_i,t}$$

Where:

$EUA_{i,t}$ = Annual initial allocation of EUAs for a single sector, i (tCO_2/y)

EUA_t = Total annual initial allocation of EUA for all sectors (tCO_2/y)

[8] Due to the significant differences in operational modalities between Phase I and the other two Phases of the EU ETS, excluding Phase I renders the modelling exercise less complicated while not compromising its robustness

[9] Note that allocation reserves are included in the overall supply determination

i	= Single sector; $i=1$ for the non-electricity sector, $i=2$ for the electricity sector
t	= Year; $t=1,2,...T$
k_i	= Number of EU ETS-covered installations in sector i; $k=1,2,...K$
$s_{k_{i,t}}$	= Initial EUA allocation of a given installation k of sector i in year t
MS	= Member State

Secondly, as installations and, by extension, sectors, have the possibility to use Kyoto credits to cover a limited part of their emissions (see Box 2), overall permit supply in the model is adjusted according to the quantity of Kyoto credits projected to be used collectively by sectors.

Sectors are assumed to use the maximum quantity of Kyoto credits allowable[10] collectively under the NAPs[11], subject to the constraint that sufficient credits are delivered to the market (see (Trotignon & Leguet, 2009)). The quantity of Kyoto credits allowed under NAPs is typically defined, as a given fraction of the EUA allocation[12]. At an aggregated EU27 level, the maximum quantity of Kyoto credits is thus:

$$\overline{SCER_t} = S_t * x_t$$

Where:

$\overline{SCER}_t$	= Maximum possible use of Kyoto credits as collectively stipulated under NAPs (tCO_2/y)

[10] The rationale being that Kyoto credits delivered to the market are by construction cheaper than the going EUA price and therefore will be used preferentially (vs. EUA) by a sector to meet permit obligations, with any excess EUA either sold (at higher price to the market) or banked for future use; In either case maximum use of Kyoto credits is consistent with rational economic behaviour (assuming Kyoto credits are cheaper) and the effect is to increase the overall emissions cap

[11] In practice, some installations, which are less informed or not well-positioned to participate in the international Kyoto credit market, may not capitalise on the opportunity to use a maximum amount of Kyoto credits. For the purpose of simplicity, this limitation is not taken into account in the model.

[12] For Phase II (2008-12) annual maximum Kyoto credits limits are known per sector. For Phase III, if installations (and by extension sectors) do not use their maximum allowed amount of Kyoto credits for Phase II, they have the right to use, in Phase III, an amount of Kyoto credits equal to the unused amount of their limit from Phase II. Trotignon (see for e.g. (CDC, 2010)) makes estimates of Kyoto credits' delivery to the market up to 2013. His estimates are adopted for the model. The difference in amount between this estimated quantity of Kyoto credits and the (NAP-) dictated maximum quantity of Kyoto credits for Phase II is taken as the maximum Kyoto credits amount for Phase III.

x_t = EU-aggregated annual limit for the use of Kyoto credits as a fraction of the EU-wide initial annual EUA allocation (%)

As MS may define a limit for Kyoto credit use at sectoral level (rather than simply a global limit), the EU-aggregated fraction, x_t, is determined by taking a weighted average of the maximum limits defined across all MS and across all sectors, that is:

$$x_t = \frac{\sum_i \left(S_{i,t} * x_{i,t} \right)}{\sum_i S_{i,t}}$$

$$x_{i,t} = \frac{\sum_{MS} \left(S_{i,t}^{MS} * x_{i,t}^{MS} \right)}{\sum_{MS} S_{i,t}^{MS}}$$

Where:

$S_{i,t}^{MS}$ = Annual EUA allocation by a given MS to sector, i (tCO_2/y)

$x_{i,t}^{MS}$ = Maximum proportion of Kyoto credits allowed by a given MS for a given sector, i, with respect to the MS' total annual EUA allocation to the sector (%)

The quantity of Kyoto credits actually delivered to the market may be above or below the global maximum allowed by the NAPs. The use of Kyoto credits is therefore given by:

$$CER_t = \min\left(\overline{SCER_t}, \overline{\overline{SCER_t}} \right)$$

CER_t = Kyoto credits procured collectively by EU ETS sectors (tCO_2/y)

$\overline{\overline{SCER_t}}$ = Quantity of Kyoto credits actually delivered to the market for trade (tCO_2/y)

Global permit supply, S_t at a given time is therefore **exogenously** given by:

Equation 1: Total annual supply of CO_2 emission permits

$$S_t = \sum_i \sum_{MS} \sum_{k_i} s_{k_i,t} + CER_t$$

S_t = Global annual CO_2 permit supply (tCO_2/y)

2.3 Permit demand

Total demand of ETS sectors is a result of actual emissions, which are a function of sectors' activity level and their realised abatement. The latter is modelled taking into account sectors' anticipation of the EU ETS permit price over the medium-term, as will be described in Sections 2.3.1and 2.3.2.

Sectors' anticipated permit price is represented as:

$$\widetilde{p_t} = p_t + \varepsilon_{p_t}$$

With:

$$\mathrm{E}\left[\widetilde{p_t}\right] = p_t\,;\ \varepsilon_{p_t} \sim N\left(0, \sigma_{p_t}^2\right)$$

Where:

$\widetilde{p_t}$ = Sectors' anticipated permit price with expectation, p_t (€/tCO_2)

p_t = Expectation of the anticipated permit price (€/tCO_2)

ε_{p_t} = Error in the anticipated price, represented by a random variable with zero mean and variance $\sigma_{p_t}^2$

The anticipated EUA price is thus subject to uncertainty.

We assume that sectors form the same anticipations regarding the medium term permit price, under the assumption that they have access to the same information, thus:

$$\mathrm{E}_i\left[\widetilde{p_t}\right] = \mathrm{E}_1\left[\widetilde{p_t}\right] = \mathrm{E}_2\left[\widetilde{p_t}\right] = p_t$$

Rubin (1996) and Schennach (2000) demonstrate that, in a competitive permit market with full banking and borrowing, the price path of permits grows at the interest rate. In accordance with this, within a give Phase, sectors' anticipated permit price would follow a trajectory given by[13]:

Equation 2: Price trajectory within a single Phase

$$p_{n+1}^{m} = p_{n}^{m}\left(1+r\right)$$

Where:

p_n^m	= Sectors' anticipated Phase permit price in year n of Phase m
m	= II, III,...(Phases II, III etc.)
r	= Interest rate (%)

The expectation p_t of anticipated permit price is therefore represented as a set of "Phase prices", that is:

$$\left\{p_t\right\} = \left\{p^m\right\}_{m=II,III\ldots} * \left(1+r\right)^t$$

Where:

p^m	= Sectors' (constant-value) anticipated permit price for a given Phase m, actualised to the starting year of the model (Phase II; $m = II$) (€/tCO_2)

The concept is illustrated in Figure 3 below.

[13] Full banking and borrowing is not exactly the case in the EU ETS – while there is full banking, in the case of borrowing, as it is only possible for installations/sectors to borrow permits from the allocation of the subsequent year (year n+1), there is a technical limit dictated by the quantity of year n+1 allowances allocated; in practice this constraint is not attained, thus for the purposes of simplicity we consider that there is also full borrowing between any two successive years within an EU ETS Phase

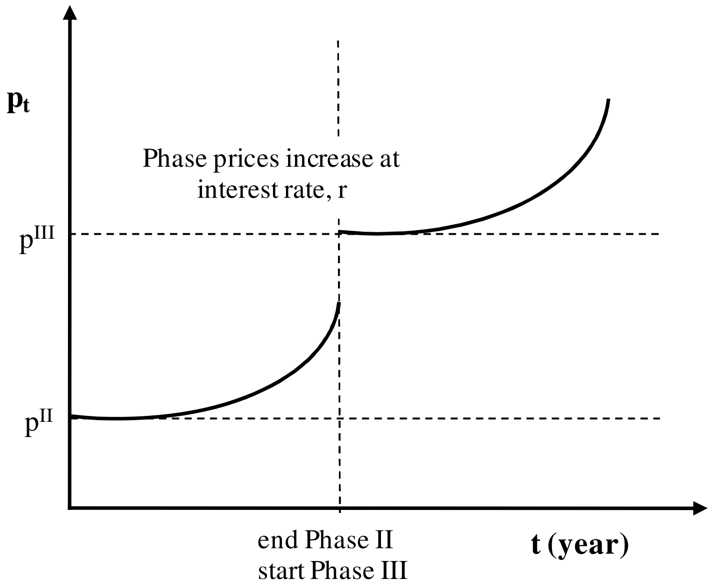


Figure 3: Permit prices in the case of full intra-Phase banking/borrowing

Sectors are therefore taken to adopt a single (constant-value) permit price as the basis for their abatement decision for all years within a given Phase.

The relationship between time, t, and the years, n, in a given Phase, m, of N_m years is:

$$t = n + \delta$$

Where: $n = 1, 2, ... N_m$; the years within a given Phase , m

$\delta = 0$,for $m = 2$;

$\delta = \sum_{k=2}^{m-1} N_k$, for $m > 2$

The subsequent sections explain the way in which electricity and non-electricity sectors' emissions are determined while taking into account the anticipated Phase permit price.

2.3.1 Non-electricity sector

The non-electricity sector (designated by subscript 1) is taken to have annual counterfactual emissions given by:

$$\tilde{Y}_{1,t} * em_{1,t}$$

Where:

$\tilde{Y}_{1,t}$ = Projected annual non-electricity sector production (€ /yr)

$em_{i,t}$ = Emissions factor for the non-electricity sector, in the absence of a carbon price (tCO_2/€)[14]

With:

$$\widetilde{Y}_{1,t} = Y_{1,ref} * \widetilde{GDPindex_{1,t}}$$

$Y_{1,ref}$ = Reference level of production for the sector in the base year, taken at $t = 1$ (€)

$\widetilde{GDPindex_{1,t}}$ = Projected EU27 index of gross domestic product (GDP) for the non-electricity sector in year t, relative to the base year index

With a base year $GDPindex_{ref}$ of 1, the projected GDP index is represented as:

$$\widetilde{GDPindex_{1,t}} = \left(1 + \widetilde{GDPgrowthRate_1}\right)^t = \left(1 + GDPgrowthRate_1 + \varepsilon_{GDP_1}\right)^t$$

$$\varepsilon_{GDP_1} \sim N\left(0, \sigma^2_{GDP_1}\right)$$

$GDPgrowthRate_1$ = Average projected GDP growth rate[15]

ε_{GDP} = Error in the projected economic activity, represented by a random variable with zero mean and variance, σ^2_{GDP}

Activity and counterfactual emissions in the non-electricity sector are therefore subject to uncertainty.

The overall abatement cost structure for the non-electricity sector $(i = 1)$ as a whole is assumed to be of the form:

$$C_{1,t} = \tfrac{1}{2} c_1 a_{1,t}{}^2$$

[14] As the non-electricity sector is composed of several emissions-producing activities, each activity resulting in the production of a different good of varying added value and emissions, the emissions factor for this sector is an aggregated weighted-average emission factor for all activities making up the sector. The weights correspond to the share of each activity's added value in the added value attributable to the sector as a whole. As these shares may evolve over time the emissions factor is time-dependent.

[15] Average projected GDP growth rate will be specified on the basis economic projections for the EU27, or, where possible, on the basis of sectoral growth rates (in the case of the non-electricity sector the sectoral growth rate would be an aggregated value of the growth rates of the sectors comprising it)

Where c_1 is the constant cost coefficient of abatement for the sector and, $a_{1,t}$, the quantity of emissions reduction effected per unit time by the sector, at time t. The underlying assumptions are linearly increasing aggregated marginal abatement costs and unchanging abatement technology during the considered period, hence a constant cost coefficient. Given the time period under consideration (a period of 13 years if the abatement strategy is adopted for a horizon to 2020 (end of Phase III)), unchanging abatement technology (constant cost coefficient) is not an unreasonable assumption. Taking the first derivative we have, for the sector, an aggregated marginal abatement cost at any given time of:

$$MC_{1,t}(a_{1,t}) = c_1 a_{1,t}$$

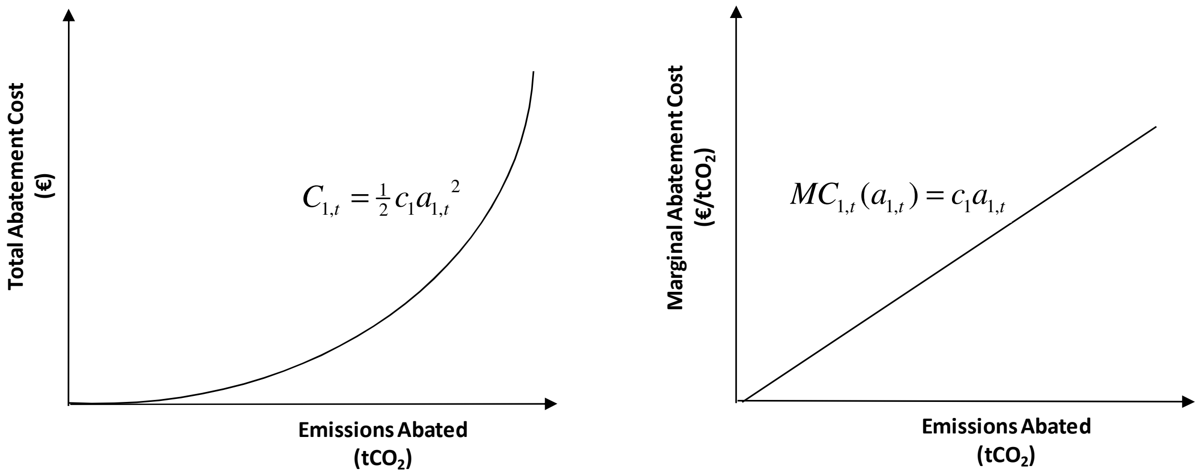


Figure 4: Assumed form of Abatement cost and Marginal Abatement Cost for the non-electricity sector

In a competitive market, the sector, acting rationally in its own interest, will adopt its abatement strategy so as to equalize its marginal abatement cost and its anticipation of the permit price; and buy (sell) the missing (excess) permits in the market at the prevailing market rate. The non-electricity sector therefore adopts an abatement strategy, in accordance with its anticipation of the permit price as follows:

$$MC_{1,t}(a_{1,t}) = c_1 a_{1,t} = E_1\left[\widetilde{p_t}\right] = p_t$$

Where $t = (1, 2, \ldots T)$, with T the last year the period for which the abatement strategy is adopted.

The cumulated level of emissions abatement to year, t, is thus:

$$a_{1,t} = \frac{MC_{1,t}}{c_1} = \frac{p_t}{c_1}$$

Where:

$a_{1,t}$ = Quantity of emissions reduction effected per unit time by a given sector (tCO_2/y)

c_1 = Abatement cost coefficient for the non-electricity sector ((€.y) / $(tCO_2)^2$)

And resulting demand for emissions permits is given by:

Equation 3: Non-electricity sector permit demand

$$\widetilde{EM_{1,t}} = Y_{1,ref} * \widetilde{GDPindex_{1,t}} * em_{1,t} - \frac{p_t}{c_1}$$

$\widetilde{EM_{1,t}}$ = Emission permit demand for the non-electricity sector (tCO_2/yr)

2.3.2 Electricity sector

The electricity sector is represented by an EU27-aggregated power production park, composed of a range of electricity (and emissions-) producing technologies. The emissions of the sector depend on the mix of technologies deployed in electricity production for meeting demand, since each technology is associated with a different fuel and thus different per unit emissions.

Given the varying nature of electricity demand (refer to Figure 5) and the characteristics of the range of energy technologies available, certain types of technology will be suited to meeting demand at different parts of the load curve (see Figure 6). As such, some technologies will be used almost continually for meeting baseload demand requirements, whereas others will be made to operate for shorter periods of time during peak demand periods. The technology mix deployed to meet demand at a given time is determined on the basis of merit order dispatch: technologies are deployed in order of increasing short-term marginal (variable) cost of production (fuel cost + variable O&M costs + carbon emission costs) until total aggregated production is sufficient to meet demand at the given point in time.

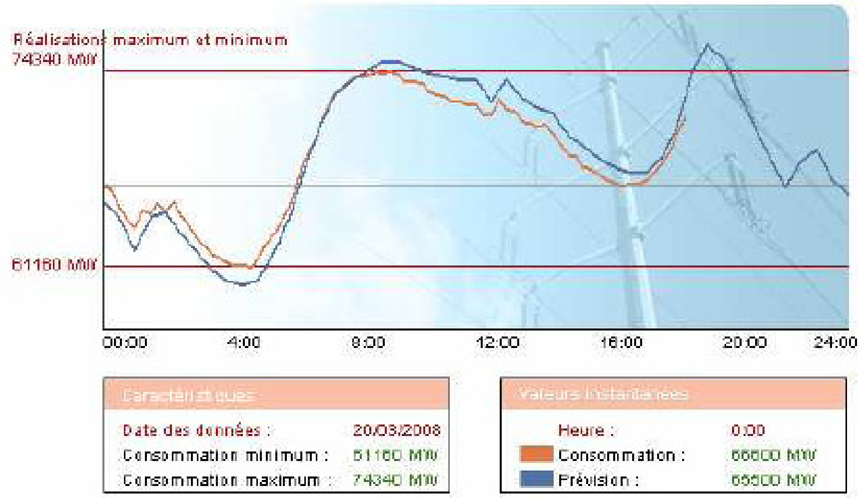


Figure 5: Typical electricity load curve for a single weekday (20/03/2008)

(Source: RFE website, taken from (Sassi, 2008))

The load curve shows the evolution of electrical energy consumption (demand) over a period of 24 hours. The figure shows that a certain minimum power (approx. 61 GW) is required to be guaranteed at all times (baseload), whereas a high amount of power (here, 74 GW approx.) is required for only relatively short periods of time (peak and high-peak). Given, the varying techno-economic characteristics of available power production technology, certain technologies, such as nuclear, which have very low operating costs and are relatively inflexible in terms of production output, are more suited for baseload operation (i.e. for the majority of the time), whereas others, such as oil- and gas-based technologies, which have higher operating costs but which can be made to operate more flexibly are more suited for peak or high-peak operation (i.e. during limited periods of higher demand).

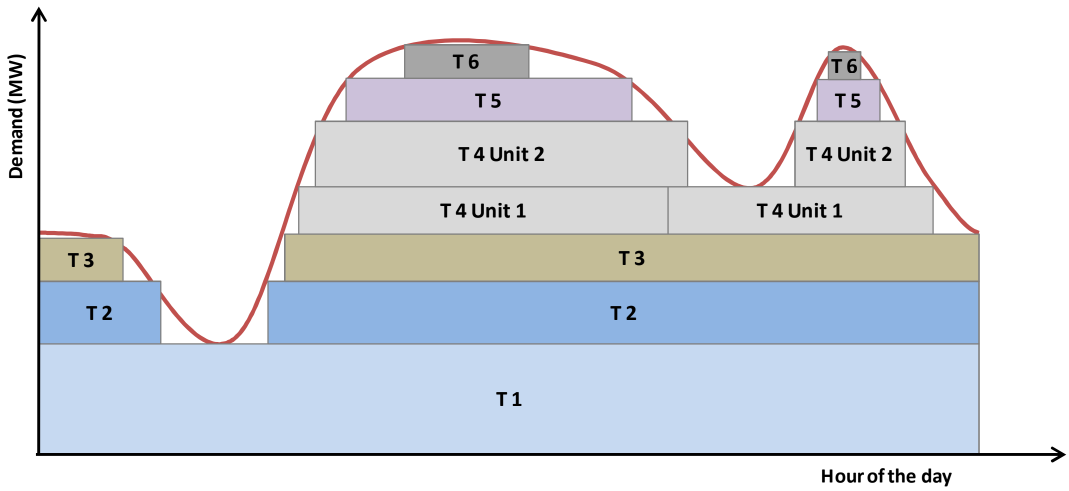


Figure 6: Filling of the load curve by merit order

The diagram illustrates the merit order principle for dispatching of various technologies according to their techno-economic characteristics, and the demand characteristics or load curve. Technologies are numbered in order of increasing short-term marginal (variable) cost of electricity production, so that T1 has the lowest short-run marginal cost and T6 the highest. With the merit order principle demand is met by stacking technologies, moving from cheaper to gradually more expensive technologies, until the demand is met. As such, Technology T1 is seen to operate for the entire period of 24 hours, whereas technology T6 only operates for a few hours at high peak periods.

Emissions of the electricity sector are therefore determined, on one hand, by the activity level, as represented by the load curve or demand profile, and, on the other hand, by the technologies making up the electric power park at any given time. They are the aggregated emissions from all technologies used in the overall electricity production for meeting demand. That is, for an annual basis:

$$\widetilde{EM}_{2,t} = \sum_{j \in J} \widetilde{Y}_{j,t} * \frac{em_j}{\rho_j}$$

$\widetilde{EM}_{2,t}$ = Annual emission permit demand for the electricity sector (tCO_2/yr)

em_j = Emission factor associated with technology, j, as determined by the fuel associated with the technology (tCO_2/MWh primary energy)

ρ_j = Energy conversion efficiency of the technology j (MWh delivered/MWh primary energy)

$\widetilde{Y}_{j,t}$ = Projected annual electricity production from technology j (MWh/y)

2.3.2.1 The influence of the production decision on electricity sector emissions

From an annual perspective it is more convenient to represent demand using an annual (load) duration curve (see Figure 7). The duration curve, together with the application of the merit order principle, are used in the model to determine annual electricity production from each technology, $Y_{j,t}$, and corresponding sector emissions. In the model, the load curve is approximated by a staircase type function. As in (Sassi, 2008), the load curve is segmented into seven ranges (with units, hours/year): 730 (high-peak period), 2190, 3650, 5110, 6570, 8030, 8760 (baseload). The duration curve is constructed for each year assuming the ratio between high-peak power demand and baseload power demand remains constant and equal to the value used in the Imaclim model (cf. Sassi (2008)), as supplied from the POLES model. By using stepwise linear approximation, the duration curve associated with an estimated EU27-wide demand $\widetilde{D}_{2,t}$ is obtained by resolving the set of linear equations:

Equation 4: Load curve determination

$$\frac{baseMW_t}{peakMW_t} = bpRatio$$

$$\left(baseMW_t * 8760 + \left(\frac{peakMW_t - baseMW_t}{6} \right) * \left(8030 + 6570 + 5110 + 3650 + 2190 + 730 \right) \right) = E\left[\widetilde{D}_{2,t} \right]$$

Where:

$baseMW_t$ = Baseload power demand (MW)

$peakMW_t$ = High-peak power demand (MW)

$\widetilde{D}_{2,t}$ = Estimated total annual electricity demand (MWh)

Electricity sector demand is determined in a similar manner to *production* in the non-electricity sector:

$$\widetilde{D}_{2,t} = D_{2,ref} * \left(1 + \widetilde{GDPgrowthRate_2} \right)^t = D_{2,ref} * \left(1 + GDPgrowthRate_2 + \varepsilon_{GDP_2} \right)^t$$

$$E\left[\widetilde{D}_{2,t} \right] = D_{2,ref} * \left(1 + GDPgrowthRate_2 \right)^t$$

$\widetilde{GDPgrowthRate_2}$ = Projected EU27-wide rate of growth of for the electricity sector

$GDPgrowthRate_2$ = Expected average EU27-wide rate of growth of for the electricity sector

$D_{2,ref}$ = Reference level of demand for the electricity sector ($t = 1$) (MWh/y)

Box 3: Operation and investment planning and role of the load curve

The load duration curve is an aggregation of the demand profiles or load curves (cf. Figure 5) from all 365 days of the year into a single curve; it is constructed not according to chronological order, as in the case of the curve of Figure 5, but according to power demand over an annual period. As such, the duration curve gives the quantity (or percentage) of time over the year for which a given demand (power) level (in MW) is equalled or exceeded. Alternatively speaking, it shows the (proportion of) time for which a given electrical capacity is required.

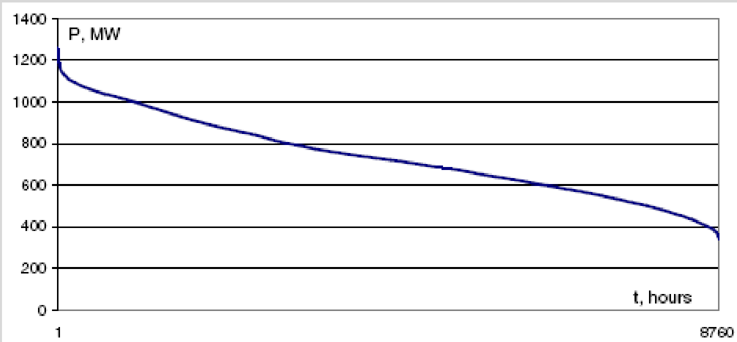


Figure 7: Example of a load duration curve. The vertical axis represents power demand in MW and the horizontal axis time in hours for a single year (Source: (Liik et al, 2004))

The area under the duration curve corresponds to the annual electricity demand in MWh. If the load curve is approximated by a staircase type function, for each segment of the function, the horizontal distance between the vertical axis and the edge of the step represents the cumulated duration of time (hours of operation) annually for which a given power demand (in MW) (given by the height of the step) required to be satisfied. By filling the load curve according to the merit order principle (see Figure 8), using *flexibly* and *partially* installed capacities, we obtain the capacities of various technologies needed to be put into production for meeting each demand level and duration period, at lowest cost. In this way, we obtain the optimal technology mix and production per technology for calculating corresponding sector emissions.

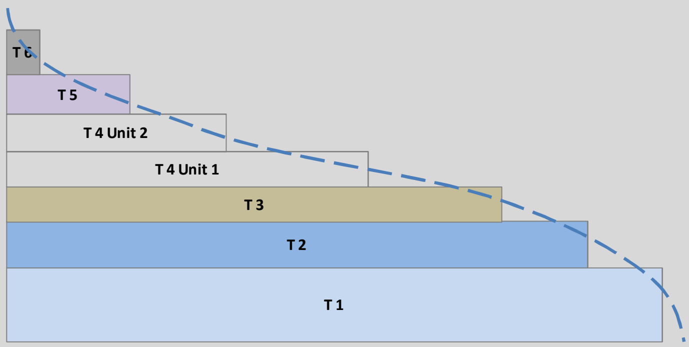


Figure 8: Annual load duration curve and the cost-competitive technology mix

The production decision is based on meeting demand at minimal marginal cost of production (minimal variable operating cost) subject – given the inertia of the sector – to the installed capacities of the various technologies in the park in the given year in question. The model programme is thus to select, for each defined range in the duration curve, technologies in order of increasing marginal cost of production (€/MWh), up until the point where their combined installed capacities (MW) when operated for the time (hours) dictated by the range, allow demand (MWh) to be met (taking into account conversion efficiencies and availabilities (%)). With the resulting technologies and capacities optimally selected for each range, the annual production output and emissions from each technology can be determined.

Mathematically this is represented as:

Equation 5: Determination of the technology mix in electricity production

$$\min_{Y_{j,t}} \sum_j \left(E\left[\widetilde{MC_{j,t}} \right] * Y_{j,t} \right) = \min_{D_{j,t,range}} \sum_{range} \sum_j \left(E\left[\widetilde{MC_{j,t}} \right] * D_{j,t,range} * hrs_{range} * availFactor_j * \rho_j \right)$$

Subject to:

$$Y_{2,t} = \sum_{range} \sum_j \left(D_{j,t,range} * hrs_{range} * availFactor_j * \rho_j \right)$$

$$\geq D_{2,ref} * \left(1 + GDPgrowthRate_2\right)^t \text{ (area under the load curve)}$$

$$\sum_{range} D_{j,t,range} \leq capMW_{j,t}$$

Where:

$$\widetilde{MC_{j,t}} = \frac{\widetilde{pFuel_{j,t}} + em_j * \widetilde{p_t}}{\rho_j} + OMvar_j$$

And with resulting expected emissions:

$$E\left[\widetilde{EM_{2,t}} \right] = \sum_{range} \sum_j \left(em_j * D_{j,t,range} * hrs_{range} * availFactor_j * \rho_j \right)$$

$availFactor_j$ = Annual full-load availability factor of a kilowatt of capacity installed for the technology j

$capMW_{j,t}$ = Installed capacity of technology j at time t (MW)

$D_{j,t,range}$ = Deployed capacity of technology, j, used to meet demand (MW) for a given range of the load curve

hrs_{range} = Annual cumulated hours of operation, equivalent to the hours within the range over which the given demand is to be met

j = Electric power production technology

$OMvar_{j,t}$ = Variable operation and maintenance costs for technology j (€/MWh)

$\widetilde{pFuel_{j,t}}$ = Anticipated long term price of fuel associated with a given technology (€/MWh primary energy)

$\widetilde{p_t}$ = Anticipated carbon permit price (€/tCO_2)

$Y_{2,t}$ = Expected (average) annual electricity production (MWh/y)

Technologies' conversion efficiencies and availability factors are assumed constant within each year and from year to year over the period[16].

Similar to the GDP index, long term fuel prices are uncertain, and are anticipated by the electricity sector to be $pFuel_t$, the average or expected value, that is:

$$\widetilde{pFuel}_{j,t} = pFuel_{j,t} + \varepsilon_{pFuel}$$

$$\varepsilon_{pFuel} \sim N\left(0, \sigma^2_{pFuel}\right)$$

$pFuel_t$ = Expected value of the anticipated long term fuel price (€/MWh primary energy)

ε_{pFuel} = Error in the projected fuel price, represented by a random variable with zero mean and variance, σ^2_{pFuel}

Importantly, the minimisation programme includes anticipated CO_2 permit price as a parameter, which means that emissions resulting out of the production decision represent EU ETS-constrained emissions (versus counterfactual emissions). Moreover, to the extent that the production decision makes a technology dispatch selection taking into account average annual fuel prices of different technologies, the outcome embodies any fuel switching that may be expected to occur under average (annual) conditions.

[16] Further model development may take into account improvements in conversion efficiencies over time for certain technologies

Equation 6: Electricity sector permit demand

$$\widetilde{EM_{2,t}} = \sum_j \widetilde{Y}_{j,t}\left(p_t, \widetilde{pFuel}_{j,t}, OMvar_{j,t}, \rho_j, \widetilde{GDPgrowthRate_2}, capMW_{j,t}\right) * \frac{em_j}{\rho_j}$$

2.3.2.2 The influence of the investment decision on electricity sector emissions

As mentioned in the previous section, the deployed technology mix and thus emissions resulting from the production decision are contingent on the profile of the existing power park, namely, the technological content and installed capacities at any given time; if the park is composed only of coal-based and gas-based technology then, irrespective of the relative economic attractiveness of nuclear production, demand in year t is necessarily met with coal and/or gas. A given unit of production capacity of technology j implemented at any given date t is considered to remain part of the electricity park until date $t + lifetime_j$, where $lifetime_j$ is the lifetime of technology j. At the same time, each year, installations in the power production park come to the end of their economic lifetime and are either retired and replaced (with the same or different technology), or are made to operate beyond their economic lifetime; the park as a whole is therefore characterised by a cross-section of production units and technologies of varying vintages. Irrespective of the need to replace end-of-life technology, progressive economic growth may require additional power production capacity to keep pace with increasing electric power demand. As such, new investment will be needed to bridge the gap between a depreciating electric power park and growing demand according to:

$$\sum_j \left(investMW_{j,t} * \rho_j * availFactor_j\right) \geq demandMW_t - \sum_j \left(depCapMW_{j,t} * \rho_j * availFactor_j\right)$$

$$depCapMW_{j,t} = \sum_j \left(capVintageMW_{j,t-1}^{vintage}\right)_{\{age_{j,t} < lifetime_j\}}$$

Where:

$investMW_{j,t}$ = Capacity investment in technology j in year t (MW)

$depCapMW_{j,t}$ = Aggregated installed capacity of technology j, with vintage year prior to t, which is not yet at the end of its lifetime at time t, (MW)

$capVintageMW_{j,t-1}^{vintage}$ = Ensemble of production installations of a given technology j, of various vintages, which are in the park at time $t-1$

$age_{j,t}^{vintage}$ = Age of technology of a given vintage at time t

$lifetime_j$ = Lifetime of the technology j (yrs)

Here, we assume negligible lead time for implementation. In effect, we determine the investment required in year t to respond to the demand in that year, given the park capacity which becomes fully depreciated by year t, and the prevailing demand in year t.

Given the relation between emissions and technology mix, the technological composition of investment in the electric power park will be determinant in the future emissions of the sector. Effectively, the electricity sector's technology choices for investment in new capacity embody the sector's long term abatement strategy. The sector's investment decision regarding replacement or additional capacity – and thus its abatement strategy – is modelled explicitly. The method consists of determining, for the duration of the compliance period, the optimal investment in additional capacity (and its technological content) for meeting demand, taking into account for each year t: sunk investment (i.e. the park already in place), any retired capacity, and changes in demand. The optimal technological composition of the new capacity investment is that which will minimise the total overall cost of the park over (i.e. summing over all years in) the compliance period. It is represented by the txj matrix, $investMW_{j,t}$.

In any given year, the total cost includes: for newly invested capacity only, fixed costs (investment and fixed O&M costs) and anticipated lifetime variable costs, and, for the existing (old) capacity, the variable costs[17] arising from operation of these technologies and capacities used to meet demand in that year. The specification of the cost in this way conditions the investment decision upon exploiting as much (and as economically feasible) as possible the existing park (annual variable costs only) to meet demand before investing in new capacity (lifetime variable and fixed costs).

The variable cost of "old" technology is the variable cost of production (€/kWh) multiplied by production (kWh) from that technology for meeting demand in year t. It should be noted that the latter, which is a result of the optimal production mix (Equation 5), depends on $capMW_{j,t}$ (the park capacity and technology composition at the given time) and thus on past investment decisions. It is thus dependent on $investMW_{j,t}$, and as such, optimal production per technology

[17] Given that the existing park is a sunk investment, the cost associated with it is limited to the variable costs of operation, whereas for the new investment, the total lifetime cost must be considered (in each year subsequent to the investment year in question, it would also be treated as sunk investment)

(sunk and new investment) and associated annual variable costs of production in each year – for sunk and new investment combined – are determined simultaneously with the optimal investment decision. To avoid double-counting, the variable cost of production attributable to the (optimal) new capacity investment in each given year t, is separated from the remainder of the lifetime variable costs associated with the new capacity investment, as shown in Equation 7 (3rd and 1st components respectively of Equation 7).

Again, as the costs associated with carbon dioxide emission are integrated directly in the investment decision, by inclusion of the permit price in the calculation of the variable costs[18], the abatement strategy of the electricity sector is implicit in its investment decision.

The total cost related to a given profile of technology investment in the power park for all years over a period T is:

Equation 7: Total cost related to a given technology

$$TC=\sum_{t=1}^{T}\frac{1}{(1+r)^t}\left(\sum_{n=t+1}^{n=t+lifetime_j}\frac{1}{(1+r)^n}\sum_j\left(VarCost_n*investMW_{j,t}*\rho_j*availFactor_j*8760\right)\right)$$
$$+\sum_{t=1}^{T}\frac{1}{(1+r)^t}\left(\sum_j investMW_{j,t}*\left(CInvest_{j,t}+OMfixed_{j,t}\right)\right)$$
$$\sum_{t=1}^{T}\frac{1}{(1+r)^t}\left(\sum_{range}\sum_j\left(E\left[VarCost_t\right]*D_{j,t,range}*hrs_{range}*availFactor_j*\rho_j\right)\right)$$

Subject to:

$$Y_{2,t}=\sum_{range}\sum_j\left(D_{j,t,range}*hrs_{range}*availFactor_j*\rho_j\right)$$
$$\geq D_{2,ref}*\left(1+GDPgrowthRate_2\right)^t \text{ (=area under the load curve)}$$

$$\sum_{range}D_{j,t,range}\leq capMW_{j,t}$$

Where:

$$VarCost_t=\left(\frac{\widetilde{pFuel_{j,t}}+em_j*\widetilde{p_t}}{\rho_j}\right)+OMvar_j$$

$$capMW_{j,t}=investMW_{j,t}+depCapMW_{j,t}$$

Where:

[18] Cf. The variable cost used as the basis of the production dispatch decision

TC = Total cost of a given investment strategy for the compliance period (€)

r = Discount rate

$CInvest_j$ = Investment cost for technology j (€/MW)

$OMfixed_j$ = Fixed operation and maintenance costs for technology j (€/MW)

From the above set of equations we see that the investment decision is effected subject to meeting overall expected demand $D_{2,t}$, and by selecting amongst various combinations of $capMW_{j,t}$ to find the technological composition of new investment that will result in lowest overall cost, given the specificities of the demand (namely its "division" into various ranges). Recall that $capMW_{j,t}$ is composed, at any given time, of a deterministic component, $depCapMW_{j,t}$ (the capacity of the park that represents past technology investments), and a variable component, $investMW_{j,t}$ (the capacity of the park that represents new investment in different technologies in year t). The model thus takes as given the sunk (past) technology investment $depCapMW_{j,t}$ and effectively tests various combinations (technological compositions) for $investMW_{j,t}$ to find that which results in an overall $capMW_{j,t}$ which, when taking into account the different types of load (baseload, peak-load, in-between), as specified by the load curve ranges, is the least-cost $capMW_{j,t}$ possible. We see therefore, in the investment decision, an arbitration between new, potentially lower overall- (total lifetime) cost technology and older potentially higher overall-cost technology, but for which the investment has already been made (sunk cost).

In the model, fully depreciated capacity is assumed to be retired and thus not made to operate beyond its economic lifetime. Moreover, it is assumed that no unit is taken out of production before the end of its economic lifetime.

Other considerations also come into play with respect to the final technology composition of new investment; for instance, some European countries have imposed a moratorium on new investment in nuclear energy technology. This is taken into account by examining the impact of including a constraint in the investment optimisation problem, executing the investment decision as:

$$\min_{investMW_{j,t}} \left(TC\right)$$

(possibly) Subject to:

$$capMW_{nuc,t} < 0.3 * \sum_j capMW_{j,t}$$

Where:

$capMW_{nuc,t}$ = Total installed nuclear capacity at time t (MW)

The investment result which minimises total cost for meeting electric power demand (in the presence of a carbon price) is thus determined without and with the application of a constraint on nuclear capacity (i.e. limiting nuclear to 30% of the total conventional park capacity).

The optimal investment is determined for the conventional power park only; the renewable technology market is affected by other factors – technical and economic – which mean the investment decision cannot be modelled in the same manner as for conventional technologies. Additional criteria which come into play in the investment decision for electricity production from renewable energy sources include: limits on technical potentials; grid considerations which potentially limit the allowable production/injection of electricity from intermittent renewable energy production; typically higher production costs; various national-level incentives in the way of subsidies, feed-in tariffs, green certificate systems etc. In effect, investment in renewable energy capacity in the model is done exogenously, and is specified by the modeller according to various scenarios, taking into consideration industry and European Commission targets and projections from other studies and models. In the model, the exogenous additional capacity investment in the renewable energy technology park, for each year, is considered *fait accompli* at the instant of executing the investment decision for the conventional technology park. At each time step t therefore, the load curve calculated from Equation 4 is shifted downward[19] by a quantity of demand (MW) equal to the "effective renewable energy capacity" in the park at each time t. The effective capacity for a given renewable energy technology is essentially the installed capacity of the renewable energy technology multiplied by its estimated average annual capacity factor. The total of effective capacities across all renewable energy technologies gives the estimated (effective) baseload equivalent (in MW) of renewable energy capacity. Due to grid constraints, the model verifies

[19] All renewable energy capacity is affected to the longest (base) ranges of the duration curve due to priority dispatch treatment; the result for the duration curve is thus a shift downwards in the entire duration curve.

the aggregated share of renewable electricity production to see if it exceeds 40% of total electricity production in that year.

The total electricity cost integrating the permit price, as calculated above, reflects the cost if emission permits are auctioned, i.e. the full cost of a technology's (installation's) emissions is borne at the outset. In the case where a new installation is granted free allowances (as has been common practice for Phases I and II), the real costs related to CO_2 emission will not be the cost for the totality of technologies' emissions, as given by Equation 7, but only costs for emissions that are in excess of allowances. This alters the cost of each technology, in favour of higher-emitting plants. However, the final impact of free allowances on the ranking of technologies is not estimated to be significant, since: (a) free allowances are de-facto inferior to actual emissions, coherent with the principle of a constraining emissions cap, and (b) free allowances will only be given up to 2012 (for the electricity sector), whereas the lifetime of a newly-built plant is generally 30-40 years (at least up to say 2040, for a plant built in 2008), meaning that auctioning is more likely to be a guiding principle for long-term technology investment for the sector[20].

The investment decision alters the sector's theoretical overall carbon emissions factor from what it would be in the absence of the EU ETS regulation. Consider that the sector has a range of electricity (and emissions-) producing technologies $j \in J^i$ some of which are already in place in its existing park, and all of which are available for it to choose to invest in for the future; the electricity generation park at any given time is characterised by its technology mix, $x_{j,t}$, the relative proportion of the various technologies making up the overall electrical generation capacity at any time. The emissions factor corresponding to the available power production park at a given time, t, is:

$$em_{2,t} = \sum_j (x_{j,t} * \frac{em_j}{\rho_j}) \; ; \; \sum_j x_{j,t} = 1 \;\; \forall t$$

Where:

$em_{2,t}$ = Theoretical emission factor of for the entire electric power park (tCO_2/MWh delivered)

[20] For Phase III auctioning will be the major mechanism for acquisition of allowances: in the electricity sector 100% of allowances will be auctioned from 2013, while in other sectors the proportion of free allocation will be 80% in 2013 decreasing to 30% in 2020

We suppose that the set of available technologies J does not change over the time period, that is, all electricity generation technologies which can be implemented are already known, moreover, they can be characterised by a cost and an emissions factor. With the introduction of a price for carbon via the permit price, the cost-competitiveness ranking of lower-emitting technologies improves. In making its investment decision therefore, it may be more attractive for the sector to invest in lower-emitting technologies, such as natural gas combined cycle, compared to higher-emitting technologies, such as thermal coal. As a result, the relative proportions, $x_{j,t}$, characterising the technology mix evolve with time, in a way that may be different from the case where there is no permit price. Through incorporation of an anticipated carbon permit price, the sector's investment decisions directly reflect any EU ETS-induced emissions reductions, and abatement is implicit in the investment strategy. To reflect the impact of the investment decision on emission, Equation 6 is broken down:

Equation 6a: Electricity sector permit demand

$$\widetilde{EM_{2,t}} = \sum_j \widetilde{Y}_{j,t}\left(p_t, \widetilde{pFuel}_{j,t}, OMvar_{j,t}, \rho_j, \widetilde{GDPgrowthRate_2}, capMW_{j,0}, CInvest_{j,t}, OMfixed_{j,t}\right) * \frac{em_j}{\rho_j}$$

2.4 Equilibrium and model resolution technique

From the above, the equilibrium equation of the model is:

Equation 8: Demand-Supply equilibrium

$$\sum_t \left[\begin{array}{l} \sum_i \sum_{MS} \sum_{k_i} s_{k_i,t} + CER_t = Y_{1,ref} * E\left[\widetilde{GDPindex_{1,t}}\right] * em_{1,t} - \frac{p_t}{c_1} \\ + \sum_j Y_{j,t}\left(p_t, pFuel_{j,t}, OMvar_{j,t}, \rho_j, GDPgrowthRate_2, capMW_{j,0}, CInvest_{j,t}, OMfixed_{j,t}\right) * \frac{em_j}{\rho_j} \end{array} \right]$$

Figure 9 shows the exogenous and endogenous variables of the model, while Figure 10 shows, schematically, the technique by which the model resolves the equilibrium problem under conditions of perfect foresight to determine the equilibrium permit price. The period covered is 2008 to 2020 (Phases II and II). In the first instance, this period is treated as a single Phase, that is, full banking and borrowing is allowed between all years of the period. The net result from banking and borrowing transactions for the period under such conditions is zero: sectors have no interest to have extra permits at the end of the compliance period (as they are then worthless) and at the end of the compliance period there is no possibility to borrow from future periods. Banking and borrowing are therefore not explicitly modelled in this version of the model.

Here, as perfect foresight is assumed, the values of all input variables are taken to be known by market actors with certainty. The following are therefore taken as known for all years in the period 2008-20:

- Permit supply $\sum_{i}\sum_{MS}\sum_{k_i} s_{k_i,t}$ to 2020
- The availability of Kyoto credits on the EU ETS market
- Growth in non-electricity sector production, $GDPgrowthRate_1$
- Growth in electricity sector demand, $GPDgrowthRate_2$
- Long term fuel prices, $pFuel_t$

The model is fed with an initial permit price (assumed by the modeller), which is the constant-value anticipated permit price for the 2008-20 Phase, in 2008-money. Based on the permit price, the model: a) formulates an optimal abatement strategy for the non-electricity for the period and b) determines the optimal operating and investment strategies for the electricity sector for the period. Emissions, and thus permit demand in the face of the input permit price, are then calculated according to Equation 3 and Equation 6, summing over the entire period 2008-20.

If the resulting equilibrium equation (Equation 8) returns a value significantly different from zero, then it means that the initially assumed EUA price is too low or too high. Based on this information the model chooses a new permit price. The supply-demand calculations are reiterated and the process is repeated until the chosen permit price results in equilibrium. The iterations are done automatically by an internal Matlab solver. The emerging price (at the end of the iterations) is the price under certainty.

In its current state, the model does not take into account the aviation sector, and emissions are limited to emissions of carbon dioxide only. Permit supply includes permits set aside for new market entrants.

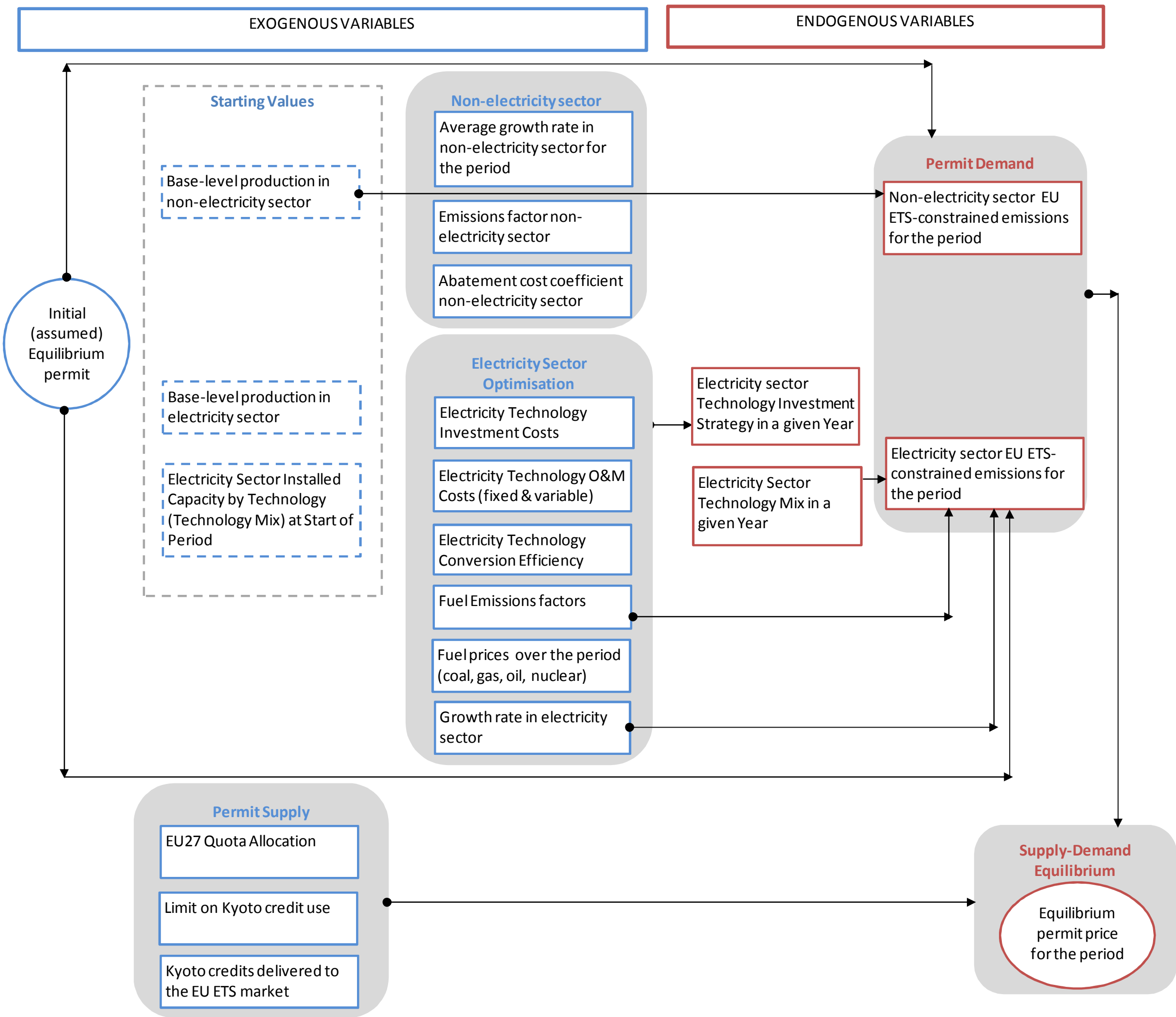


Figure 9: Exogenous and endogenous variables of the model

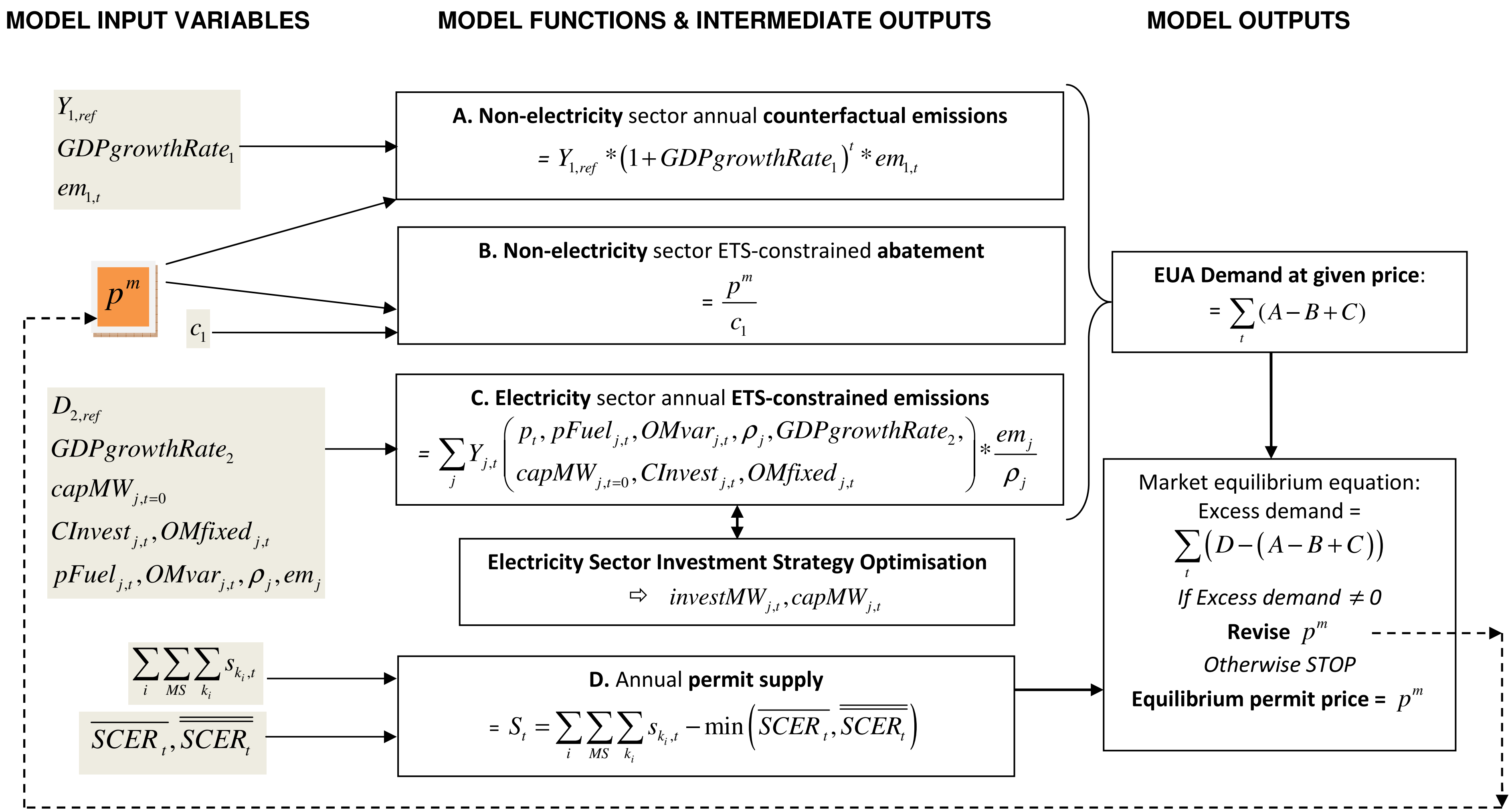


Figure 10: Model resolution technique with full banking and borrowing and perfect foresight

3 Discussion

The proposed model represents emissions in electricity and non-electricity EU ETS sectors and the resulting supply-demand equilibrium permit price for the case of full banking and borrowing. It incorporates relevant approaches of existing work in energy-emissions modelling, adopting a bottom-up approach for estimation of emissions in the electricity sector and a top-down approach for the non-electricity sector. By focussing on the EU ETS perimeter and a medium term time horizon the model fills a niche not currently covered by simulation and optimisation models, which have a much broader perspective and typically longer horizons; nor by existing econometric models which are situated in the short-term.

Importantly, the model allows comparative analyses of emissions and abatement effort in electricity and non-electricity sectors for example, under various scenarios of economic activity, and, in particular, exploration of the interdependencies involved. To-date significant attention has been given to abatement in the electricity sector[21], where the abatement opportunities are well understood and where a majority of abatement is expected to occur. Analysis of emissions data from the first Phase would indicate that the abatement achieved to date[22] cannot be attributed to short-term dynamics in the electricity sector (e.g. fuel switching), nor even to the electricity sector by itself. The proposed model will enable analysis of the longer term (investment) dynamics at work in the electricity sector's abatement, as well as the role played by non-electricity sectors.

In its current stage of development the model incorporates EU ETS institutional variables and the detailed representation of the electricity sector, which is currently being validated and tested. In addition, the model specification is currently for the case of perfect foresight. The next step will be elaboration of the non-electricity sector emissions relationship and abatement cost structure, with validation on the basis of historic data and previous studies. More work is also required in the quantification of sector-level GDP indices (for both electricity and non-electricity sectors), potentially linking it with the wider macroeconomic context, for example via elasticities of demand for goods of EU ETS-sectors in accordance

[21] See for example Delarue et al. (2008) for an analysis of short-term abatement from fuel switching in the electricity sector

[22] See for example Ellerman and Buchner (2008) for an estimation of the overall emission abatement achieved during the first years of the EU ETS

with EU-wide GDP. Ultimately, the goal is to integrate and analyse the impact of uncertainty in model input variables on actor strategies, that is, on: investment/abatement and banking/borrowing. This will require representation of the borrowing constraint between Phases II and III and passing to iteration at an annual level.

Once fully operational, the model will provide a tool to conduct analyses of specific situations of interest to EU ETS policy-makers and market actors. In terms of policymakers, it can be used to provide input for the future development and design of the EU ETS: it could, for example, be used to explore the impact of alternative architectures on emissions and permit prices, such as the implementation of a price cap and/or floor or an increase or decrease in the maximum allowed use of international Kyoto credits. In terms of current EU ETS market actors, it can be used to provide insight on the repercussions for permit demand and prices of, for instance: economic changes (e.g. economic crisis, which impacts sectors' activity and thus emissions) or energy market changes (e.g. high coal prices, impacting the electricity sector's production and investment decisions and thus emissions).

Annex 1. Categories of activities, and installations currently covered by the EU ETS

Source: (EC, 2003)

Activities	Greenhouse gases
Energy activities	
Combustion installations with a rated thermal input exceeding 20 MW (except hazardous or municipal waste installations)	Carbon dioxide
Mineral oil refineries	Carbon dioxide
Coke ovens	Carbon dioxide
Production and processing of ferrous metals	
Metal ore (including sulphide ore) roasting or sintering installations	Carbon dioxide
Installations for the production of pig iron or steel (primary or secondary fusion) including continuous casting, with a capacity exceeding 2,5 tonnes per hour	Carbon dioxide
Mineral industry	
Installations for the production of cement clinker in rotary kilns with a production capacity exceeding 500 tonnes per day or lime in rotary kilns with a production capacity exceeding 50 tonnes per day or in other furnaces with a production capacity exceeding 50 tonnes per day	Carbon dioxide
Installations for the manufacture of glass including glass fibre with a melting capacity exceeding 20 tonnes per day	Carbon dioxide
Installations for the manufacture of ceramic products by firing, in particular roofing tiles, bricks, refractory bricks, tiles, stoneware or porcelain, with a production capacity exceeding 75 tonnes per day, and/or with a kiln capacity exceeding 4 m^3 and with a setting density per kiln exceeding 300 kg/m^3	Carbon dioxide
Other activities	
Industrial plants for the production of	Carbon dioxide
(a) pulp from timber or other fibrous materials	
(b) paper and board with a production capacity exceeding 20 tonnes per day	Carbon dioxide

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