Quantifying CO$_2$ abatement costs in the power sector

Kenneth Van den Bergh, Erik Delarue
University of Leuven (KU Leuven) – Energy Institute
Celestijnenlaan 300 box 2421, B-3001 Leuven, Belgium
phone: +32 16 372 860
e-mail: kenneth.vandenbergh@mech.kuleuven.be

Abstract
CO$_2$ cap-and-trade mechanisms and CO$_2$ emission taxes are becoming increasingly widespread. This paper examines the relation between a CO$_2$ emission cost and CO$_2$ emission reductions in the power sector. The authors present a new methodology that deepen the insight in the relation between a CO$_2$ cost and CO$_2$ abatement. The methodology adresses both the robustness issue and the granularity issue related to marginal abatement cost curves (MACCs). The methodology is based on a bottom-up approach, starting from engineering knowledge of the power sector, and applied to the Central Western European power system.

Keywords
CO$_2$ emission policy, marginal abatement cost curves, power sector.

1. Introduction

Policy measures aiming at reducing CO$_2$ emissions are becoming increasingly widespread. In this respect the power sector plays an important role due to its notable share in total emissions (about 30% of European CO$_2$ emissions originate from the power sector) and its considerable abatement potential.

Two main types of (direct) emission policies exist; a price instrument imposing a fixed payment per emitted unit (e.g., a CO$_2$ emission tax) and a quantity instrument imposing an aggregated emission cap, possibly combined with a trade mechanism in emission allowances (e.g., a cap-and-trade mechanism). Both types of policy result in a cost of emitting CO$_2$. A widely used tool to think about the impact of emission policy is the concept of marginal abatement cost curves (MACCs). A MACC plots the shadow price corresponding to an emission constraint of increasing severity against the quantity abated. A point on the MACC represents the marginal cost of abating an additional unit of emissions (Ellerman and Decaux, 1998). As such, a MACC links emission abatement to an emission cost (being a CO$_2$ tax or a CO$_2$ price$^1$).

Roughly speaking, two main methods are used to develop MACCs. The first method consists of a top-down approach based on macroeconomic models, most often in a general equilibrium framework. The second method uses a bottom-up approach, based on detailed optimization models or expert knowledge of a system, mostly in a partial equilibrium framework (Jacoby, 1998). The advantage of the top-down approach is that it aims to capture all effects of a CO$_2$ cost, including feedback loops like changes in fossil

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$^1$ Throughout this paper the term CO$_2$ cost is used, expressed in EUR/tCO$_2$. A CO$_2$ cost might reflect a CO$_2$ price within a cap-and-trade mechanism (e.g., the European Emission Trading System) or a CO$_2$ tax.
fuel prices. However, these top-down models are limited to less detailed representations of each sector and each country. The engineering bottom-up approach allows a very detailed description of a certain sector, but this comes at the expense that not all effects and feedback loops in the system can be captured (Jacoby, 1998). The trade-off between bottom-up and top-down models is a reoccurring discussion in energy systems modeling and often aspects from both approaches are combined (Labandeira et al., 2009). Models often referred to in the literature on MACCs are, among others, the EPPA model of MIT (Paltsev et al., 2005), the POLES model developed by IEPE (European Commission, 2010; Criqui et al., 1999) and the DART model developed at the Kiel Institute for World Economics (Klepper et al., 2003).

Although MACCs are a commonly used tool to analyze the impact of a CO₂ cost on CO₂ abatement – or vice versa, some general issues can be raised with regard to these curves. For the construction of MACCs, models are used often based on a centralized optimization, with perfect information. In reality, specific technical constraints, and elements of imperfect information and risk perception result in abatement measures getting implemented over a range of CO₂ price, rather than on distinct CO₂ prices. MACCs are also rather static snap-shots. As CO₂ prices rise, measures will get implemented and learning effects will be triggered. In this regard, as different abatement measures relate to different time horizons (e.g., pure operational measures versus long term investments) it might not be straightforward putting them on a single axis. When derived from modeling (either top-down or bottom-up), some further reflections are to be made regarding MACCs. Kesicki and Ekins (2012) give an overview of the shortcomings of MACCs, with robustness being one of the most critical ones. Each model used to derive MACCs is based on external parameters like, for instance, fuel prices and capital costs. A MACC is robust if it is insensitive to changes in these parameters. In the literature, consensus seems to be that MACCs are not very robust (Klepper and Peterson, 2006; Fischer and Morgenstern, 2006; Delarue et al., 2010; Morris et al., 2012). Another issue with regard to MACCs is the level of granularity. A MACC with high granularity might give a detailed cost-emission relation of a single abatement technology, without taking account of overlapping and mutually influencing abatement technologies. On the other hand, a MACC with low granularity might give an aggregated cost-emission relation but without revealing the driving technology of the abatement at a certain CO₂ emission cost.

This paper addresses both the robustness issue and the granularity issue related to marginal abatement cost curves, applied to the power sector. A new methodology is developed, based on knowledge of the drivers of CO₂ emissions in the power sector. The methodology provides insight in the way that a MACC is composed combining several abatement technologies (i.e., the granularity issue). Besides the methodology illustrates how changes in external parameters influence the MACC (i.e., the robustness issue). The main objective of the presented methodology is to deepen the understanding of the relation between a CO₂ emission cost and CO₂ emission abatement in the power sector.

The presented methodology is based on a bottom-up approach. To this end, a partial equilibrium model of the power sector is used, describing the power sector with a high level of detail. The methodology is illustrated with a case study of the Central Western European (CWE) power sector (Germany, France, Belgium, The Netherlands, and Luxembourg).

Section 2 describes a framework to think about CO₂ emissions and CO₂ abatement in the power sector. Section 3 presents the new methodology to derive MACCs and section 4 discusses the applications of this methodology on a case study of the Central Western European power sector. Section 5 concludes.
2. CO₂ emissions in the power sector: a framework

Different parameters that influence the CO₂ emissions from the power sector can be identified and classified in 3 main categories of CO₂ emission drivers in the power sector:

(1) the composition of the conventional power plant portfolio;
(2) the residual load to be met by the conventional power plant portfolio;
(3) the marginal generation costs of the conventional power plant portfolio.

Each of these drivers is discussed more in detail in this section.

2.1. The conventional generation portfolio

The conventional generation portfolio consists of power plants that can be actively controlled by utilities. The most common conventional units are nuclear power plants and fossil fuel fired power plants (coal, gas, lignite, and fuel oil). Renewables generation (wind and sun) can only be actively controlled to a limited extent and is therefore not considered as part of the conventional portfolio (but accounted for in the residual load).

The composition of the conventional generation portfolio is a first important driver of the CO₂ emissions in the power sector. Depending of the fuel mix and the average power plant age (impacting, among others, the operating efficiency), portfolios can have very different CO₂ intensities. To illustrate this, Figure 1 shows the CO₂ intensity of electricity generation for some European Member States. The French generation portfolio consists mainly of nuclear power plants and hydro power plants, resulting in a very low CO₂ intensity. Electricity generation in Poland, on the other hand, is to a large extent based on coal and lignite fired plants, resulting in a high CO₂ intensity. The other shown member states have CO₂ intensities between these two relative extreme values.

CO₂ abatement can be achieved by changing the installed conventional generation capacity or its technical parameters. Possible abatement actions are (non-exhaustive list):

- investments in nuclear power plants (CO₂ free electricity generation);
- investments in new gas fired plants (relatively low CO₂ emissions);
- closing down lignite or coal fired plants (relatively high CO₂ emissions);
- retrofitting existing fossil fuel fired plants (resulting in a higher efficiencies);
- implementing carbon capture and storage.

A CO₂ cost might trigger CO₂ abatement by changing the conventional power plant portfolio through one of the listed abatement options. Conventional power portfolios are relatively inert, implying that a CO₂ cost causes CO₂ abatement by changing the composition of the conventional portfolio only in the long term. For example, typical lead times for new conventional plants ranges from 2 years for combined cycle units up to 7 years for nuclear units (IEA, 2010).
2.2. The residual load

The residual load that has to be met by the conventional power portfolio is the original electricity demand minus generation from renewables and cogeneration units. Logically, the higher the residual load, the higher the CO$_2$ emissions from the power system.

CO$_2$ abatement can be achieved by reducing the residual load. Possible abatement actions are (non-exhaustive list):

- investments in renewable generation capacity (wind and sun);
- increasing the energy efficiency of electrical appliances;
- demand reduction due to higher electricity prices.

A CO$_2$ cost might trigger CO$_2$ abatement by decreasing the residual load through one of the listed abatement options. Decreasing the residual load plays a role in the medium term. For example, lead times of new wind and solar capacity are about 1 year (IEA, 2010). In the short term (days to weeks), electricity demand is rather inelastic. In the medium term, however, the electricity demand can be expected to be partially elastic, representing, among others, investments in efficient appliances.

2.3. The marginal generation costs

The marginal generation costs of the available conventional plants determine the merit order. The merit order is a ranking of all available power plants in ascending order of marginal generation cost. The intersection of the merit order with the residual electricity load divides the power plant portfolio in operating power units, i.e., the ones at the left of the intersection, and non-operating power plants, i.e., the ones at the right of the intersection$^2$ (see Figure 2). Power plants with low marginal generation costs are thus more likely to be online than power plants with higher marginal generation costs. At current fuel and CO$_2$ prices in Europe, the ranking in the merit order is roughly speaking the following: nuclear units, lignite fired units, coal fired units, gas fired units and fuel oil fired units. At the time of writing, coal fired plants are hence more likely to produce in Europe than gas fired power plants.

CO$_2$ abatement can be achieved by changing the marginal generation costs of conventional power plants, resulting in so-called fuel switching. Fuel switching occurs when the marginal generation cost of high-

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$^2$ This is only true by approximation. Dynamic power plant constraints might cause power plants with higher marginal generation costs to be online while plants with lower marginal costs are offline.
emitting plants (e.g., coal fired plants) becomes higher than the marginal generation cost of low-emitting plants (e.g., gas fired plants), leading to a switch of these plants in the merit order ranking. The result is that more generation is coming from low-emitting plants and overall CO₂ emissions decrease.

A CO₂ cost might trigger fuel switching by increasing the marginal generation costs of emitting units. Fuel switching is a pure operational abatement technology, responding fast to a CO₂ cost (power plant operators schedule their plants on an hourly to daily basis).

Figure 2. Merit order of the CWE region (based on 2012 data) and the inelastic residual load. NUC: nuclear units, SPP-L: lignite fired steam power plants, SPP-C: coal fired steam power plants, SPP-G: gas fired steam power plants, CCGT: combined cycle gas turbines, OCGT: open cycle gas turbines, IC: internal combustion.

2.4. Summary

This section discusses the three main drivers of CO₂ emissions in the power sector. All possible abatement options can be divided into one of these drivers. Each driver is linked to a certain time frame. Table I summarizes this section. Note that an abatement option can be triggered by a CO₂ cost, but also by other energy and climate policies (e.g., renewables support schemes can trigger investments in renewables) or by macroeconomic evolutions (e.g., changing fuel prices might trigger fuel switching). The focus in this paper is on a CO₂ cost triggering CO₂ abatement.

<table>
<thead>
<tr>
<th>CO₂ emission driver</th>
<th>Possible abatement options</th>
<th>Time frame</th>
</tr>
</thead>
<tbody>
<tr>
<td>conventional portfolio</td>
<td>• investments in nuclear power plants</td>
<td>long term (several years)</td>
</tr>
<tr>
<td></td>
<td>• investments in gas fired plants</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• closing down lignite or coal fired plants</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• retrofitting fossil fuel fired plants</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• carbon capture and storage</td>
<td></td>
</tr>
<tr>
<td>residual load</td>
<td>• investments in renewable generation capacity</td>
<td>medium term (months-years)</td>
</tr>
<tr>
<td></td>
<td>• increasing the efficiency of appliances</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• demand reduction due to higher electricity prices</td>
<td></td>
</tr>
<tr>
<td>marginal generation costs</td>
<td>• fuel switching</td>
<td>short term (days-months)</td>
</tr>
</tbody>
</table>
3. Methodology

The framework presented in section 2 can be used as a basis to develop a methodology to study MACCs, considering the robustness issue and granularity issue related to MACCs.

3.1. Analysis plan

Based on the insights in the CO\textsubscript{2} emissions drivers, a detailed marginal abatement cost curve of the power sector can be composed in three steps:

1) Quantify the relation between a CO\textsubscript{2} cost and each of the 3 drivers of CO\textsubscript{2} emissions in the power sector (conventional portfolio, residual load and marginal generation costs). The relation between a CO\textsubscript{2} cost and a CO\textsubscript{2} driver follows from knowledge of the power sector.

2) Quantify the relation between the aggregated CO\textsubscript{2} emissions in the power sector and its 3 drivers. The aggregated CO\textsubscript{2} emissions follow from the partial equilibrium model of the power sector with varying conventional portfolio, varying residual load and varying marginal generation costs as input. The result of this step is a 4-dimensional surface (three CO\textsubscript{2} drivers plus the aggregated CO\textsubscript{2} emissions), referred to as the absolute emission plane. Each point on this 4-dimensional surface represents an operational state of the power sector.

3) Merge the information of the two previous steps to find the relation between a CO\textsubscript{2} cost and CO\textsubscript{2} emissions in the power sector. This relation leads to the marginal abatement cost curve of the power sector.

The different effects of a CO\textsubscript{2} cost on each CO\textsubscript{2} driver may not just be summed up, as the relation between a CO\textsubscript{2} emission driver and the aggregated CO\textsubscript{2} emissions depends on the other CO\textsubscript{2} emission drivers as well. For instance, a change in marginal generation costs – caused by a CO\textsubscript{2} cost – has a different effect on the CO\textsubscript{2} emissions, depending on the change in residual load – caused by the same CO\textsubscript{2} cost. This indicates interaction between the different CO\textsubscript{2} emission drivers, which is captured by the partial equilibrium model and represented by the emission plane.

If a parameter which is external to the analysis changes (e.g., fossil fuel prices, capital costs of renewables), the first and the third step of the analysis plan have to be repeated. This illustrates the robustness issue. Changes in external parameters affect the MACC.

In the third step of the analysis plan, several abatement technologies are combined into one single CO\textsubscript{2} cost-emission relation. The bottom-up nature of this methodology allows decomposing the total CO\textsubscript{2} abatement in its driving abatement technologies. This relates to the granularity issue.

The methodology, which is described in rather abstract terms up until now, will be illustrated in section 4 for a real-life case study. The MACC of the Central Western European power sector will be discussed, considering two abatement technologies triggered by a CO\textsubscript{2} cost: fuel switching and investments in wind energy. Fuel switching is an important abatement option in the power sector. Wind energy is an important source of CO\textsubscript{2} free electricity generation, with a levelized cost of electricity (LCOE) which is several times lower than the LCOE of photovoltaic energy (IEA, 2010). The case study considers a medium term time frame. Within this time frame, both fuel switching and investments in wind energy might take place. The composition of the conventional power plant portfolio, which can change only in the long term, is assumed to be fixed.
The presented methodology implicitly assumes that the three CO₂ emission drivers are independent of each other. The interdependence between marginal generation cost (fossil fuel prices), conventional power plant composition (fossil fuel fired capacity) and residual load (electricity demand and renewable investments) is not captured by the methodology. This relates to the bottom-up nature of this paper.

### 3.2. System description

The methodology is applied to the Central Western European (CWE) power sector, based on 2012 data. The CWE region covers France, Germany, Belgium, The Netherlands and Luxembourg (see Figure 3). Each country is represented by one node and market coupling is established according to the Net Transfer Capacity (NTC) method. The total installed conventional generation capacity in this region is 175 GW. The composition of the conventional portfolio is considered to be fixed in the remainder of the study. Table II gives an overview of the installed capacity together with the parameters assigned to the respective units. The average 2012 fuel prices were used as fuel prices (EEX, 2013).

The 2012 annual electricity demand in the CWE region was 1220 TWh (demand corrected for neglected import and export with countries not included in the model). 16% of this demand was fulfilled by renewable generation (wind, sun, bio, and hydro) and 13% by electricity from cogeneration units. The remaining residual load, to be fulfilled by the conventional portfolio, was 866 TWh. Historical hourly demand time series and renewable generation time series are used.


**Table II. Overview of installed capacity in the 2012 CWE region.**

<table>
<thead>
<tr>
<th></th>
<th>Capacity [GW]</th>
<th>Efficiency [%]</th>
<th>Min. output [%P_max]</th>
<th>Up/down time [h]</th>
</tr>
</thead>
<tbody>
<tr>
<td>NUC</td>
<td>82</td>
<td>33</td>
<td>50</td>
<td>168</td>
</tr>
<tr>
<td>SPP-C</td>
<td>26</td>
<td>35/40/46</td>
<td>43</td>
<td>6</td>
</tr>
<tr>
<td>SPP-L</td>
<td>22</td>
<td>35/40/46</td>
<td>43</td>
<td>24</td>
</tr>
<tr>
<td>SPP-G</td>
<td>4</td>
<td>35/40/46</td>
<td>32</td>
<td>5</td>
</tr>
<tr>
<td>CCGT</td>
<td>31</td>
<td>40/48/58</td>
<td>35</td>
<td>3</td>
</tr>
<tr>
<td>OCGT</td>
<td>5</td>
<td>35/42</td>
<td>30</td>
<td>1</td>
</tr>
<tr>
<td>IC</td>
<td>5</td>
<td>35/40/48</td>
<td>35</td>
<td>3</td>
</tr>
</tbody>
</table>

Figure 3. Map of Europe with the CWE region denoted in dark blue.
### 3.3. Model description

A detailed unit commitment model of the power sector is developed to simulate the CWE power system. A unit commitment model is a partial equilibrium model that determines the optimal scheduling of a given set of power plants to meet the electricity demand, taking account of operational constraints. The presented unit commitment model is pure operational (i.e., no investments in generation or transmission capacity are considered), deterministic (i.e., neglecting uncertainties in the power system) and assumes an inelastic electricity demand.

The unit commitment problem is formulated as a mixed-integer linear program (MILP) in GAMS 24.2 and solved by CPLEX 12.6 with a tolerance of 1%. Hereunder, the basic equations of the unit commitment model are listed, based on Carrión and Arroyo (2006) and Arroyo and Conejo (2000). A more extended version of the model description, including tighter and compacter formulations of the constraints, can be found in Van den Bergh et al. (2014).

Table III gives the nomenclature used in the model description.

<table>
<thead>
<tr>
<th>Sets</th>
<th>Parameters</th>
</tr>
</thead>
<tbody>
<tr>
<td>I (i) Set of power plants</td>
<td>A\textsubscript{ln} Grid incidence matrix {-1,0,1}</td>
</tr>
<tr>
<td>L (l) Set of transmission lines</td>
<td>AP\textsubscript{n,i} Matrix linking plant i to node n {0,1}</td>
</tr>
<tr>
<td>N (n) Set of nodes</td>
<td>C\textsubscript{i} Generation cost at min output in [EUR/h]</td>
</tr>
<tr>
<td>T (t) Set of time steps</td>
<td>D\textsubscript{n,t} Electricity demand in [MW]</td>
</tr>
<tr>
<td></td>
<td>F\textsubscript{i} Marginal generation cost in [EUR/MWh]</td>
</tr>
<tr>
<td></td>
<td>F\textsubscript{i}\textsubscript{max} Capacity limit in [MW]</td>
</tr>
</tbody>
</table>

The objective function of the unit commitment model is minimization of the total operational system cost, consisting of generation costs and start-up costs.

$$\min \sum_i \sum_t \left( C_i z_{i,t} + F_i p_{i,t} + \text{SUC}_i v_{i,t} \right)$$  \hspace{1cm} (1)

The objective function is subject to the market clearing condition (equation 2), renewables curtailment limits (equation 3), power plant generation limits (equation 4), minimum down and up times (equations 5-6), the logic binary relation (equation 7) and trade capacity limits (equations 8-9).

$$\sum_i \text{AP}_{n,i} \left( z_{n,t} \text{p}_{i,\text{min}} + p_{i,t} \right) + T_{n,t}^{\text{CHP}} + T_{n,t}^{\text{RES}} - u_{n,t}^{\text{RES}} = D_{n,t} + i_{n,t} \quad \forall \ n, t$$  \hspace{1cm} (2)

$$0 \leq u_{n,t}^{\text{RES}} \leq T_{n,t}^{\text{RES}} \quad \forall \ n, t$$  \hspace{1cm} (3)

$$0 \leq p_{i,t} \leq \left( \text{p}_{i,\text{max}} - \text{p}_{i,\text{min}} \right) z_{i,t} \quad \forall \ i, t$$  \hspace{1cm} (4)

$$1 - z_{i,t} \geq \sum_{t' = t+1-MDT_{i}}^{t} w_{i,t'} \quad \forall \ i, t$$  \hspace{1cm} (5)

Table III. Nomenclature used in the model description.
\[
\sum_{t'=t+1}^{t} v_{i,t'} \quad \forall \ i, t
\]

\[
z_{i,t-1} - z_{i,t} + v_{i,t} - w_{i,t} = 0 \quad \forall \ i, t
\]

\[
i_{n,t} = \sum_{l,n} A_{l,n} f_{l,t} \quad \forall \ n, t
\]

\[-F_{l,t}^{\max} \leq f_{l,t} \leq F_{l,t}^{\max} \quad \forall \ n, t
\]

The model solves a whole year with an hourly time resolution in weekly blocks. Different weekly optimizations overlap with one day and are coupled by means of sequential boundary conditions, in order to ensure a feasible and optimal coupling between the different optimizations. The model is validated so that the simulated generation in a simulation with historical input data matches the historical observed generation.

4. CO₂ cost-emission relation in the CWE power sector

The analysis plan discussed in section 3.1 is illustrated in this section based on a case study of the CWE power sector. Sections 4.1 and 4.2 show the relation between a CO₂ cost and a CO₂ driver (respectively the marginal generation costs and the residual load). Section 4.3 relates the CO₂ emission drivers with the aggregated CO₂ emissions from the power sector and section 4.4 expresses the relationship between a CO₂ cost and the CO₂ emissions.

4.1. CO₂ cost versus marginal generation costs: fuel switching

The relation between a CO₂ cost and a marginal generation cost is different for each power plant, depending on the generation type and its rated efficiency. The marginal generation cost \( MC \) of a power plant is the derivative of the total generation cost function \( TC(P) \) with respect to the power output \( P \).

\[
TC(P) = \frac{FC + EF \cdot CC}{\eta} \cdot P \quad (10)
\]

\[
MC = \frac{FC + EF \cdot CC}{\eta} \quad (11)
\]

with \( FC \) the fuel cost in [EUR/MWh\text{fuel}], \( EF \) the emission factor in [tCO₂/ MWh\text{fuel}], \( CC \) the CO₂ cost in [EUR/tCO₂] and \( \eta \) the rated efficiency. The operating efficiency of the power plant is function of the power output of the unit (the operating efficiency decreases in part load operation). However, for the sake of simplicity, the dependence of the efficiency on the power output is neglected at this point.

Equation (11) gives the relation between a CO₂ cost and the marginal generation cost of one power plant. However, a metric is required containing information about all generation costs in the power portfolio. The proposed metric is the difference between the average marginal generation cost of a coal fired power plant and the average marginal generation cost of a gas fired power plant. The rationale is that coal fired and gas fired units are the main source of fuel switching as they are operating close to the margin (i.e., close to the intersection of the merit order with the demand curve). The metric contains average marginal generation costs, averaged in time and averaged over different units (with different efficiencies).

Figure 4 shows the relation between a CO₂ cost and the difference in average marginal generation costs between coal fired and gas fired plants. The figure is based on 2012 average fuel data (12 EUR/MWh for
coal and 25 EUR/MWh for gas\(^3\), EEX, 2013) and average power plant characteristics. To investigate the impact of changes in external parameters, the relation between a \(\text{CO}_2\) cost and marginal generation costs is also considered for a case with a 10% higher coal price and the 2012 gas price, and for a case with a 10% higher gas price and the 2012 coal price. Figure 4 indicates that coal fired power plants become more expensive than gas fired power plants, in terms of marginal generation costs and at 2012 fuel prices, as of a \(\text{CO}_2\) cost of 40 EUR/t\(\text{CO}_2\).

![Figure 4](image_url)

Figure 4. Relation between a \(\text{CO}_2\) cost and the difference in average marginal generation cost between coal and gas fired power plants, used as a metric for the marginal generation costs of the conventional power plant portfolio.

### 4.2. \(\text{CO}_2\) cost versus residual demand: wind energy investments

A \(\text{CO}_2\) cost might promote investments in wind generation capacity, resulting in a lower residual demand to be fulfilled by the conventional power plant portfolio. In this study, a model is used to determine the relation between a \(\text{CO}_2\) cost and wind energy investments. The model gives the amount of installed wind capacity, assuming the conventional portfolio to be fixed and solely based on 2012 power system data (fuel prices, demand data, etc.).

The model estimates the wholesale electricity price as the marginal generation cost of the last generating unit in the merit order needed to meet the average residual demand. If the electricity price is higher than the levelized cost of electricity (LCOE) of wind, an extra MW of wind energy is installed resulting in a decrease in the average residual demand with 0.2 MW for onshore wind (20% capacity factor) and 0.3 MW for offshore wind (30% capacity factor). Then the new electricity price is calculated as the marginal generation cost of the last generating unit in the merit order needed to meet the reduced average residual demand. This electricity price will be lower than the previous calculated price. This iterative process continues until the estimated electricity price equals the LCOE of wind or the wind capacity potential is reached. The simulations are repeated for different \(\text{CO}_2\) emission costs. The model gives a rough estimation of the investments in wind triggered by a \(\text{CO}_2\) cost. The amount of installed wind is translated into a decrease in residual demand by subtracting the wind generation (estimated based on a 20% capacity factor for onshore wind and 30% capacity factor for offshore wind) from the original residual demand. Table IV shows the data used in this investment model.

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\(^3\) A coal price of 12 EUR/MWh corresponds to a price of 120 $/Tonne and a gas price of 25 EUR/MWh correspond to a price of 10 $/MMBtu (2012 dollar-euro exchange rate).
Figure 5 shows the residual demand including the additional wind generation as a function of the CO₂ cost. Again, the relation between a CO₂ cost and the residual demand is considered for a case with a 10% higher coal price and the 2012 gas price, and for a case with a 10% higher gas price and the 2012 coal price. This change in fuel prices impacts the decision of the wind investors as it changes the electricity price, but only to a limited extent. At higher fuel prices, wind investments start taking place at slightly lower CO₂ emission costs. The technical potential limit is not reached within the considered CO₂ cost range.

<table>
<thead>
<tr>
<th>LCOE [EUR/MWh]</th>
<th>Technical potential [GW]</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Wind onshore</td>
</tr>
<tr>
<td>Belgium</td>
<td>68</td>
</tr>
<tr>
<td>The Netherlands</td>
<td>58</td>
</tr>
<tr>
<td>Germany</td>
<td>71</td>
</tr>
<tr>
<td>France</td>
<td>61</td>
</tr>
</tbody>
</table>

| Table IV. Overview of the levelized cost of electricity (LCOE) and the technical potential of wind energy in the CWE region (IEA, 2010; EEA, 2009). |

4.3. Absolute emission plane

The absolute emission plane of the power sector is, in its complete form, a 4-dimensional surface, containing the relation between the three CO₂ emission drivers and the CO₂ emissions in the power sector. Each point on the absolute emission plane represents a possible operational state of the power sector, given a certain power plant portfolio composition, certain marginal generation costs and a residual load. Each point on the absolute emission plane follows from a detailed simulation for a whole year (8760 hours) with the unit commitment model described in section 3.3.

In this paper, the composition of the conventional portfolio is assumed fixed. As such, the absolute emission plane reduces to a 3-dimensional surface. Figure 6 shows the absolute emission plane of the 2012 CWE power sector. The figure indicates that absolute CO₂ emissions decrease with decreasing residual load and with increasing difference in marginal generation costs between coal fired and gas fired plants.

Note that the absolute emission plane of Figure 6 is based on specific 2012 data (e.g., 2012 time series for demand and renewables generation). Other time series would result in a slightly different absolute emission plane, however, the main trends and order of magnitudes would remain.
4.4. Deriving a marginal abatement cost curve

A marginal abatement cost curve of the power sector can be derived, based on the relation between a CO₂ cost and the CO₂ emission drivers on one hand (see section 4.1 and 4.2), and the relation between the CO₂ emission drivers and aggregated CO₂ emissions on the other hand (see section 4.3). The following steps need to be taken:

1. Indicate the appropriate reference point on the absolute emission plane, i.e., the point at zero CO₂ emission cost (see point R at Figure 7a).
2. Project the relation between a CO₂ cost and each of the relevant CO₂ emission drivers on the absolute emission plane (see dashed lines at Figure 7a). Each dashed line corresponds to a CO₂ emission driver for a CO₂ cost ranging from 0 to 100 EUR/tCO₂, assuming the other CO₂ emission drivers fixed.
3. Compose the different CO₂ cost-CO₂ driver relations into one relation between a CO₂ cost and CO₂ emissions. This latter relation is represented by a trajectory on the emission plane (see solid line at Figure 7a). The solid line is a collection of points on the absolute emission plane corresponding to the CO₂ emission drivers for a CO₂ cost ranging from 0 to 100 EUR/tCO₂.
4. In a final step, the CO₂ cost-emission relation can be expressed relative to the CO₂ emissions in the reference point, which leads to the marginal abatement cost curve (see Figure 7b).
Figure 7. The marginal abatement cost curve can be derived by projecting the CO\textsubscript{2} cost-driver relations on the absolute emission plane.

The methodology gives insight in the impact of changing external parameters. Consider again a case with a 10\% higher coal price and the 2012 gas price, and a case with a 10\% higher gas price and the 2012 coal price. These changes in fossil fuel prices impact the relation between a CO\textsubscript{2} cost and each of the CO\textsubscript{2} emission drivers (see Figures 4 and 5). As a result, the MACC of the power sector will change as well. Figure 8 shows the marginal abatement cost curve and the corresponding trajectories on the absolute emission plane for different fossil fuel prices. This example relates to the robustness issue of MACCs and shows how the proposed methodology can bring insight in the mechanisms behind a changing external parameter.

The methodology also allows breaking up the MACC in its driving abatement technologies. Figures 4 and 5 indicate that up to a CO\textsubscript{2} emission cost of 35 EUR/tCO\textsubscript{2}, all CO\textsubscript{2} abatement is caused by fuel switching. At higher CO\textsubscript{2} emission costs, both fuel switching and wind energy investments cause CO\textsubscript{2} emission abatement. The relative contribution of the different abatement technologies can be approximated based on the absolute emission plane. However, the relative contribution of the different abatement technologies can only be approximated as different abatement technologies interact with each other, meaning that the presence of one abatement technology can affect the impact of the other abatement technology. Therefore,
it is not possible to fully allocate abatement to one specific abatement technology. Figure 9 shows the contribution of fuel switching and wind energy investments in the marginal abatement cost curve of the power sector based on 2012 prices in case of no interaction between both abatement technologies (based on the imaginary case where only one abatement technology is present) and the total abatement if both abatement technologies are in place. In turns out that at higher CO₂ costs, negative interaction occurs (the total abatement caused by fuel switching and wind together is lower than the sum of the abatement if the abatement technologies are separately in place).

![Relative contribution of fuel switching and wind energy investments to CO₂ abatement.](image)

**Figure 9.** Relative contribution of fuel switching and wind energy investments to CO₂ abatement.

## 5. Conclusion

This paper presents a methodology that deepens the insight in the relation between a CO₂ cost and CO₂ emission reductions in the power sector. The methodology is based on the insight that CO₂ emissions in the power sector are driven by the composition of the conventional power portfolio, the residual load (i.e., electricity demand minus renewables generation) and the generation costs of the conventional units. The usefulness of the methodology has been demonstrated by means of a case study of the Central Western European power sector.

According to the presented methodology, a marginal abatement cost curve (MACC) of the power sector can be composed in three steps. First, the relation between a CO₂ cost and each of the CO₂ emission drivers has to be determined. Second, the relation between the CO₂ emission drivers and the CO₂ emissions in the power sector has to be determined. Third, the previous steps can be combined to a relation between a CO₂ cost and CO₂ emissions in the power sector.

The main goal of the methodology is to give additional insight in the CO₂ cost-emission relation, rather than deriving marginal abatement cost curves (MACCs). MACCs are facing the issue of robustness (i.e., sensitive to changes in external parameters) and granularity (i.e., not revealing the driving abatement technology at a certain CO₂ price). The presented methodology addresses both issues by showing the effect of changing external parameters and identifying the driving abatement technologies behind the aggregated MACC.
References


