CLIMATE CHANGE
18/2022

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Methodological approaches to quantify the impact of the UK carbon price floor

German Environment Agency

Umwelt Bundesamt

CLIMATE CHANGE 18/2022

Ressortforschungsplan of the Federal Ministry for

the Enviroment, Nature Conservation, Nuclear

Safety and Consumer Protection

Project No. (FKZ) 3717 42 503 0
Report No. (UBA-FB) FB000710

Annex A: Interaction of national emission abatement instruments with the EU ETS

Methodological approaches to quantify the impact of the UK carbon price floor

by

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On behalf of the German Environment Agency

Imprint

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/umweltbundesamt.de
/umweltbundesamt

Report performed by:
Institution
Address
Post code/Zip City
Country

Report completed in:
November 2020

Edited by:
Section Economic Aspects of Emissions Trading, Monitoring, Evaluation
Claudia Gibis

Publication as pdf:
http://www.umweltbundesamt.de/publikationen

ISSN 1862-4804

Dessau-Roßlau, May 2022

Abstract: Interaction of national emission abatement instruments with the EU ETS: Methodological approaches to quantify the impact of the UK carbon price floor

The EU emissions trading system (EU ETS) has always been part of a wider policy mix. In this paper, we focus on national policy instruments aimed at decarbonising the electricity sector and use the UK carbon price floor (CPF) as a case study to develop two methodological approaches that can quantify the impact of an overlapping policy on ETS emissions. The two approaches differ in terms of the data and computing power needed as an input and the level of detail in depicting the electricity market (e.g. UK only vs. interactions with the European market). An annual impact of 40-65 million t CO_2 is estimated for the CPF once it has reached full operation (depending on the approach chosen and whether or not imports and exports of electricity are taken into account). While a rebalancing mechanism exists in the EU ETS, namely the Market Stability Reserve (MSR), additional measures are necessary in order to fully absorb the impact of the CPF, i.e. a readjustment of the cap (e.g. by “re-basing” the Linear Reduction Factor, LRF) or unilateral cancellation of allowances. The approaches developed in this paper can provide an estimate of the impact of the overlapping policy instrument and thus help in determining the adequate amount to be compensated.

Kurzbeschreibung: Wechselwirkung zwischen nationalen Emissionsminderungsinstrumenten und dem EU-Emissionshandelssystem: Methodische Ansätze zur Quantifizierung der Auswirkungen des britischen Carbon Price Floor (CPF)

Seit seiner Einführung ist das EU-Emissionshandelssystem (EU-ETS) Teil eines umfassenden Politikmixes. In diesem Papier werden zwei methodische Ansätze entwickelt, mit denen die Emissionswirkung eines Politikinstrumentes bestimmt werden können, dessen Wirkungsbereich sich mit dem des EU-ETS überschneidet. Dabei konzentrieren wir uns auf nationale Maßnahmen, die auf die Dekarbonisierung des Stromsektors abzielen, und verwenden den britischen Carbon Price Floor (CPF) als Fallstudie, um die beiden Ansätze zu testen. Die Ansätze unterscheiden sich in Bezug auf benötigte Input-Daten und Rechenleistung sowie den Detaillierungsgrad bei der Darstellung des Strommarktes (insbesondere hinsichtlich der Berücksichtigung von Wechselwirkungen mit dem europäischen Markt). Je nach gewähltem Ansatz und je nachdem, ob Stromimporte und -exporte berücksichtigt werden oder nicht, wird die jährliche Emissionsminderung durch den CPF auf 40-65 Mio. t CO_2 geschätzt. Zwar gibt es im EU-ETS mit der Marktstabilitätsreserve (MSR) einen Ausgleichsmechanismus, diese kann aber die Auswirkungen des CPF nicht in vollem Umfang auffangen. Deshalb sind zusätzliche Maßnahmen, wie eine Anpassung der Cap, z.B. durch ein „Rebasing“ des Linearen Reduktionsfaktors (LRF) oder eine einseitige (nationale) Stilllegung von Zertifikaten, nötig. Durch die Abschätzung der Emissionsminderung durch interagierende Instrumente, können die hier entwickelten Ansätze dabei helfen, diesen Kompensationsbedarf zu bestimmen

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BEIS	Department for Business, Energy & Industrial Strategy
CO2	Carbon dioxide
CPF	Carbon price floor
CPS	Carbon Price support
EC	European Commission
EE	Energy efficiency
EEA	European Environment Agency
ENTSO-E	European association for the cooperation of transmission system operators
EU	European Union
EU ETS	EU Emissions Trading System
EUA	EU allowance
EUTL	European Union Transaction Log
GBP	British Pound
GHG	greenhouse gas
GOV	Government Digital Service
GOV	government
ICIS	Independent Commodity Intelligence Service
LRF	Linear Reduction Factor
MSR	Market Stability Reserve
Mt	Million tons
MW	Megawatt (unit of power)
NTC	net transfer capacities
PV	photovoltaics
RE	Renewable energy
t	metric tones
TP	Trading period
TWh	Terawatt hours (measuring units for energy)
UBA	Umweltbundesamt
UK	United Kingdom

Summary

Since its introduction in 2005, the EU emissions trading system (EU ETS) has been part of a wider climate policy mix. The interactions between the EU ETS and other targets, policies and measures at the EU as well as the national level can influence the balance of demand and supply within the EU ETS, its price signal and ultimately its short- and long-term efficiency. The EU has recognised the need to account for these types of imbalances by introducing the Market Stability Reserve (MSR), as well as the possibility for Member States to unilaterally cancel allowances when national measures are taken to shut down fossil electricity generation capacities. Furthermore, review clauses exist that would allow more fundamentally addressing the impact of overlapping policies by adjusting the cap (by way of the Linear Reduction Factor, LRF).

In order to carry out a meaningful adjustment, a quantification of the reduction impact of the overlapping policy or measure is necessary. In this paper, we focus on national policy instruments aimed at decarbonising the electricity sector. We use the UK carbon price floor (CPF) as a case study to develop two methodological approaches that can quantify this impact. The first approach (Tier 1) is a simplified calculation (carried out in Excel) compared to our second approach (Tier 2), which is based on a model of the European electricity market. While the second approach may have advantages regarding its precision in capturing the processes on the European electricity market (e.g. imports/exports of electricity, for example increasing CO_2 emissions outside UK due to increased electricity imports), the simpler approach uses less computing power, as well as requiring less input data. The approaches further differ in their assumptions regarding the baseline scenario, in particular as to whether or not decommissioning of power plants is attributed to the CPF. Results obtained under Tier 1 represent a "lower bound" to the impact of the CPF (no cross-border effects, no decommissioning of power plants due to the CPF), while those obtained under Tier 2 represent an "upper bound" (potential overestimation of cross-border effects, all observed decommissions attributed to the CPF).

While we develop two approaches to ex-ante model the emission impact of a given policy instrument, we apply these approaches to ex-post data of the years 2013-2017 when the CPF had its main impact on emissions from the UK electricity sector. This reduction impact is estimated at up to 10 million t CO_2 in 2014 rising to 40-65 million t CO_2 in 2017 (depending on the approach chosen and whether or not imports and exports of electricity are taken into account). Across the study period a cumulated impact on the EU ETS of 100 – 130 million t CO_2 is estimated, representing the potential allowance surplus caused by the CPF. This cumulated impact increases further in the years following 2017 until the cap is adjusted in way to account for the additional impact.

One way to carry out the adjustment would be to "re-base" the Linear Reduction Factor (LRF) governing the cap using an estimate of the mean annual impact of the policy instrument. Until such a long-term adjustment is carried out, the MSR can provide some short-term balancing of supply and demand, although it is not designed to fully absorb the impact of a policy such as the UK CPF. Unilateral cancellation of allowances seems less likely in the case of the UK (since most coal-fired capacities were already been decommissioned during the third trading period (TP) and due to the UK leaving the EU ETS after 2020).

Since we apply our ex-ante methods to ex-post data, the estimated impact of the CPF using the two approaches can be compared to actual historical data. Estimated CO_2 emissions are generally somewhat higher than historically observed values. This is mostly true for the start of

the CPF when the mark-up on carbon prices was rather small, while estimated emissions are close to historical values for the later years of the study period (2016 and 2017) when large emission impacts could be observed.

As is true for any sort of modelling, our estimations rely on a number of assumptions. Assumptions have to be made both in ex-ante modelling, but also in ex-post modelling (where an unknown counterfactual, e.g. a “no policy case”) needs to be estimated. Since results are sensitive to the approach chosen and assumptions made, the actual process of how these approaches could help towards compensating the impact of additional policy instruments, still needs to be determined. Such a process could contain elements of ex-ante projections and ex-post adjustments. As a first step, however, the approaches developed can provide an approximation of the magnitude of the adjustment necessary. Based on the estimated range of impact, an adequate course of action for compensation can be developed.

Zusammenfassung

Seit seiner Einführung im Jahr 2005 ist das EU-Emissionshandelssystem (EU-ETS) Teil eines umfassenden klimapolitischen Mixes. Die Wechselwirkungen zwischen dem EU-ETS und anderen Zielen, Politiken und Maßnahmen auf EU- und nationaler Ebene haben Auswirkungen auf Angebot und Nachfrage innerhalb des EU-ETS, die Preise der CO_2-Zertifikate und letztlich auch auf seine langfristige Effizienz. Mit der Einführung der Marktstabilitätsreserve (MSR) im Jahr 2019 und der Möglichkeit für Mitgliedstaaten, Zertifikate unilateral aus den nationalen Auktionsmengen zu löschen, wenn nationale Maßnahmen ergriffen werden, hat die EU bereits auf diese Art von Wechselwirkungen reagiert. Darüber hinaus gibt es in der ETS-Richtlinie Überprüfungsklauseln, die es ermöglichen, solche Wechselwirkungen, zusätzlich durch eine Anpassung des Cap grundlegender auszugleichen.

Um eine sinnvoll auf mögliche Wechselwirkungen reagieren zu können, ist eine Quantifizierung der Reduktionswirkung des sich überschneidenden Politikinstrumentes oder Maßnahme erforderlich. In diesem Zusammenhang liegt der Fokus dieses Papiers auf nationalen politischen Instrumenten, die auf die Dekarbonisierung des Stromsektors abzielen. Wir verwenden den britischen Carbon Price Floor (CPF) als Fallstudie, um zwei methodische Ansätze zu entwickeln, mit denen seine Auswirkungen quantifiziert werden können.

Der erste Ansatz ist eine Excel-basierte Berechnung, während der zweite Ansatz auf einem Modell des europäischen Strommarktes basiert. Während der zweite Ansatz Vorteile in Bezug auf die Genauigkeit aufweist, weil er insbesondere Wechselwirkungen mit dem europäischen Strommarkt berücksichtigt (z.B. möglicherweise steigende CO_2-Emissionen außerhalb des Vereinigten Königreichs aufgrund erhöhter Stromimporte), werden für die Anwendung des ersten Ansatzes weniger Input-Daten und weniger Rechenleistung benötigt. Die Ansätze unterscheiden sich außerdem in ihren Annahmen bezüglich des Basisszenarios, insbesondere in der Frage, ob die Stilllegung von Kraftwerken dem CPF zugerechnet wird oder nicht.

Die mit dem ersten Ansatz erzielten Ergebnisse stellen eine „Untergrenze" für die Auswirkungen des CPF dar, da keine Wechselwirkungen mit dem europäischen Strommarkt berücksichtigt werden und die Stilllegung von Kraftwerken nicht dem CPF zugerechnet wird. Die mit dem zweiten Ansatz erzielten Ergebnisse stellen hingegen eine „Obergrenze" der Wirkung des CPF dar, da sowohl grenzüberschreitenden Auswirkungen berücksichtigt als auch alle beobachteten Stilllegungen dem CPF zugeschrieben werden.

Beide hier entwickelten Ansätze sind zur ex-ante-Modellierung von Minderungswirkungen politischer Instrumente entwickelt worden, werden aber im Rahmen der Fallstudie auf historische Daten der Jahre 2013-2017 angewendet, weil dies die Jahre sind, in denen der CPF seine größte Wirkung auf die Emissionen des britischen Stromsektors hatte.

Diese Minderungswirkung wird, je nach gewähltem Ansatz, für das Jahr 2014 auf bis zu 10 Mio. t CO_2 geschätzt und auf 40-65 Mio. t CO_2 im Jahr 2017. Für den gesamten Untersuchungszeitraum werden die kumulierten Auswirkungen auf den EU-ETS auf 100 bis 130 Mio. t CO_2 geschätzt. Dieser Wert entspricht dem potenziellen Überschuss an Zertifikaten, der auf den CPF zurückzuführen ist. Der kumulierte Überschuss nimmt auch noch in den Jahren nach 2017 zu und zwar so lange bis das Cap um den gleichen Betrag nach unten angepasst wird.

Eine Möglichkeit, die Anpassung des Cap vorzunehmen, besteht darin, den Linearen Reduktionsfaktor (LRF), der für den Cap-Verlauf maßgeblich ist, anhand einer Schätzung der durchschnittlichen jährlichen Auswirkungen des CPF neu festzulegen. Bis zu einer solchen langfristigen Anpassung kann die MSR kurzfristig für einen gewissen Ausgleich von Angebot und Nachfrage sorgen, obwohl sie nicht dafür ausgelegt ist, die Auswirkungen einer Maßnahme wie

dem britischen CPF vollständig aufzufangen. Eine unilaterale Löschung von Zertifikaten scheint im Falle des Vereinigten Königreichs weniger wahrscheinlich, da die meisten Kohlekraftwerke bereits während der dritten Handelsperiode des EU-ETS stillgelegt wurden und das Vereinigte Königreich seit 2021 nicht mehr am EU-ETS teilnimmt.

Da wir unsere ex-ante-Methoden auf historische Daten anwenden, können die geschätzten Auswirkungen des CPF mit den tatsächlichen Entwicklungen verglichen werden. Die mit den Ansätzen geschätzten CO_2-Emissionen liegen insgesamt etwas höher als die in der Vergangenheit beobachteten Werte. Dies gilt vor allem für den Beginn des CPF, als der Aufschlag auf die Kohlenstoffpreise eher gering war. In den späteren Jahren des Untersuchungszeitraums (2016 und 2017), in denen große Auswirkungen des CPF auf die Emissionen zu beobachten waren, liegen unsere Schätzungen jedoch nahe an den historischen Werten.

Wie jede Art der Modellierung beruhen auch unsere Schätzungen auf einer Reihe von Annahmen. Dabei müssen Annahmen sowohl bei der ex-ante-als auch bei der ex-post-Modellierung getroffen werden, da bei letzterer immer eine unbekannte kontrafaktische Situation, z. B. eine "Situation ohne politische Maßnahmen", geschätzt werden muss. Da die Ergebnisse von dem gewählten Ansatz und den getroffenen Annahmen abhängen, muss der tatsächliche Prozess, wie verlässliche Schätzungen für die Emissionsminderung überlappender Instrumente erzielt werden können, noch festgelegt werden. Ein solcher Prozess könnte Elemente von ex-ante Projektionen und einer ex-post Überprüfung dieser Minderungswirkung enthalten.

In einem ersten Schritt können die hier entwickelten Ansätze jedoch einen Näherungswert für die Größenordnung der Emissionswirkung und der erforderlichen Cap-Anpassung liefern. Auf der Grundlage der geschätzten Bandbreite der Auswirkungen kann eine angemessene Vorgehensweise für den Ausgleich entwickelt werden.

1 Introduction

Since its introduction in 2005, the EU emissions trading system (EU ETS) has been a pillar of European climate policy. Other energy and climate policy instruments both at the European and national level complement and interact with the EU ETS. At the European level, these include, for example, the promotion of renewable energy sources and policies aimed at reducing energy demand by increasing energy efficiency. Further policy instruments are being implemented at national level, such as those aimed at reducing electricity generation from lignite and hard coal.

The ETS is a cap and trade scheme, which - by limiting the amount of emissions that the entities covered by the scheme are allowed to emit - creates a price for emissions and thus incentivises emission reductions. This price depends on the scarcity of allowances on the market, which in turn is determined by the number of allowances available compared to emissions under a business as usual scenario.

The amount of allowances available is subject to a political decision that determines at what rate emissions should decline, i.e. which cap is set on future emissions. If the future demand for emissions is overestimated and the cap is set too high, prices will be low and the ETS may fail to incentivise meaningful emissions reductions. If the imbalance between supply and demand persists, the ETS is reduced to a backstop function: It will ensure that the reduction targets set in those sectors covered by the ETS are met but will not contribute substantially to emission reduction. This can hamper the long-run efficiency of the system and become a problem if, for example, reduction targets are made more ambitious (which is necessary to meet commitments made under the Paris Agreement). Setting the right cap level is therefore essential to tap into the potential of the ETS to deliver cost-effective emission reductions.

The EU ETS has always been part of a wider policy mix (del Río et al. 2013; Matthes 2010; Hood 2011) and overlapping policy instruments and measures have been taken into account, at least partly, when setting the cap for the third and fourth trading period of the EU ETS in particular by taking into account the EU-wide renewable energy and energy efficiency targets, as well as several national policies. Nevertheless, emission projections made in the context of setting the cap for the third and fourth trading periods likely overestimated the future emissions level. This has several reasons:

- The EU targets on renewable energy and energy efficiency have been strengthened after the cap was set and their impact is likely to have been underestimated.
- A key driver of emissions in projections is economic growth, a variable official projections are notoriously optimistic about.
- Additional measures have been introduced and existing policies reducing emissions in the ETS sectors were strengthened after the definition of the cap.

With the revised Directive for the fourth trading period of the EU ETS, the European Union (EU) (2018) has made the supply of allowances more flexible in order to react to imbalances in the market that might arise due to these factors and also to deal with the huge surplus of allowances that has built up from 2009 onwards.

- The MSR – a mechanism that adjusts the supply of allowances based on the amount of allowances in circulation – has started operation in 2019.

- The Directive also includes a cancellation provision by way of which countries are allowed to unilaterally cancel allowances when emission-intensive electricity generation capacity is decommissioned.

Both mechanisms are most suitable for addressing short-term imbalances. Structural imbalances between the supply and demand of allowances are best dealt with by adjusting the overall cap, which can be done between trading periods or in line with the Global Stocktake under the Paris Agreement.

In order to adequately reflect additional greenhouse gas (GHG) savings not taken into account when the cap was set, a deeper understanding of the interactions between the EU ETS in its current form and other climate policy instruments at the European and national level is required.

The goal of this paper is to develop two methodological approaches to quantify the change in the demand for allowances caused by the impact of interacting policy instruments. One of the approaches (Tier 1) is developed as an Excel model. The second approach is based on an electricity market model (Tier 2) and serves as a more in-depth analysis of the impact of overlapping policies, as well as a check on the results obtained using the first approach.

The remainder of this paper is structured as follows. In a first step, the way in which additional policy instruments interact with the EU ETS is explored in Section 2. We define in what case the impact of a given policy or measure is likely to be considered in the cap and when it can be considered additional (in which case it may contribute to an imbalance between the demand and supply of allowances not intended by the policy maker). In Section 3, we use the UK carbon price floor (CPF) as a case study along which the two methodological approaches are developed. The CPF is a measure that was introduced in 2013 after the cap for the third trading period was set and contributed to substantial emission reductions in the British power sector. The two methods are used to estimate the additional emission reduction due to the CPF. These results are compared, and we derive implications for the applicability of the two different methods (to the case of the CPF and more generally). Section 4 discussed the compensation mechanisms available to rebalance supply and demand in the EU ETS and how results on the impact of overlapping policies and measures may be used in this context. Section 5 summarises and concludes.

2 Interaction of complementary targets, policies and measures with the EU ETS

The cap of EU ETS in its third and fourth trading period was conceived against the backdrop of a triad of EU-wide goals for 2020 and 2030 regarding greenhouse gas emission reductions, renewable energy deployment and energy efficiency improvements. In addition, several national policies and measures were taken into account in the modelling underlying the cap setting carried out in the relevant Commission's impact assessments (European Commission (EC) 2008, 2014).

On the one hand, targets, policies and measures may be newly conceived or strengthened after the impact assessment was carried out and the cap was set. On the other hand, the modelling of future emission developments in the impact assessment may not correctly capture the impact of interacting targets, policies and measures. These two possibilities are explored in the following.

2.1 Renewable energy and energy efficiency targets at EU level

The impact assessments assume that EU-wide renewable energy (RE) and energy efficiency (EE) targets - in force at the time of modelling - are reached, without specifically spelling out the policies and measures needed to reach those targets, as these are to a large part enacted at the level of Member States. While the target system of GHG, RE and EE targets may have been coherent when set up[1], changed conditions may lead to an overshoot in one of the targets in case the other two targets are met. Examining the 2020 triad of targets, Fraunhofer ISI (2013) shows that due to changes in the economic development newer scenarios (i.e. PRIMES 2009 vs. PRIMES 2007) predict that reaching the 20% EE- and 20% RE-target is expected to result in a reduction of GHG emissions of 27% below 1990 levels in 2020, thus overshooting the set 20% target and potentially contributing to a surplus of allowances in the EU ETS.

Targets, policies and measures that are adopted or strengthened after the setting of the cap could – for obvious reasons – not be taken into account when the cap was set. This is the case for two targets that have significant impact on ETS emissions: As part of the Clean Energy Package, the EU has increased its 2030 targets for renewable energy and energy efficiency. The share of energy from renewable sources in the EU is to at least stand at 32% of gross final energy consumption, energy efficiency to be improved by at least 32.5% by 2030. Both directives include an upward revision clause by 2023. This was not foreseen when the ETS cap for the fourth trading period was set. In fact, the 40% GHG reduction scenario modelled in the impact assessment leads to 26.5% of renewables in gross final energy consumption and an increase in energy efficiency of 25.1% (CEZ Group 2016).

2.2 National or regional policies and measures targeting emissions-intensive electricity generation

The impact assessment for 2030 specifies that the reference scenario includes the full implementation of policies adopted by late spring 2012. Any additional measures on EU, national or regional level approved after this date were likely not taken into account for the cap setting.

In recent years, national policies and measures targeting coal-fired electricity generation have gained momentum. Following the adoption of the Paris Agreement, governments, subnational

[1] There is some evidence that the ETS cap of the third and fourth trading periods was not sufficiently coordinated with the RE and EE targets (Gibis et al. 2019; International Emissions Trading Association (IETA) 2015; Pöyry et al. 2017).

governments and businesses have teamed up in the "Power Past Coal Alliance". Participating governments pledge to "commit to phasing out existing traditional coal power and placing a moratorium on any new traditional coal power stations without operational carbon capture and storage, within our jurisdictions."[2] or are "in the process of developing and implementing ambitious actions on coal phase-out."[3] As of December 2019, 33 national governments have signed the declaration, out of them 18 are countries participating in the EU ETS (Austria, Belgium, Denmark, Finland, France, Germany, Greece, Ireland, Italy, Latvia, Liechtenstein, Lithuania, Luxembourg, Netherlands, Portugal, Slovakia, Sweden, United Kingdom). The undersigning governments have announced dates by when they aim to being coal-free: France and Sweden by 2022, Slovakia by 2023, Austria, Ireland, Italy and UK by 2025, Greece by 2028, Finland by 2029, Denmark, Hungary, Netherlands and Portugal by 2030 and Germany by 2038. In some of the countries no coal fired power plants are active (Belgium, Latvia, Lithuania, Liechtenstein, Luxembourg).[4]

2.3 Which targets, policies and measures are additional?

In order to define whether a target, policy or measure is additional to the ETS cap (i.e. was or could not be taken into account for cap-setting) and may thus lead to an imbalance in the supply and demand of allowances over and above what was intended, the following questions can be asked.

- **Is a policy or measure explicitly or implicitly included in the impact assessments used to define the cap?**
  If a policy or measure is explicitly mentioned in the impact assessment to the 2020/2030 package, it has to be assumed that the effect of the policy on GHG emissions under the EU ETS was factored in and that hence the policy is not additional. One has to keep in mind that not all policies are explicitly modelled in the underlying scenarios, in particular when it comes to policies and measures intended to meet the RE and EE targets, which are defined at the national level.

  If this is the case, the policy or measure is assumed to be **not additional**.

- **Does a policy or measure contribute to an increase or overachievement of the renewable energy and energy efficiency targets as modelled in the impact assessment?**
  An additional impact from policies designed to meet the EU's renewable energy and energy efficiency targets can be expected, if i) the impact of these targets on GHG emissions was underestimated, ii) these targets are increased at EU level or iii) these targets are increased or overshot at the level of individual countries (and not counterbalanced by underachievement in other countries).

  If this is the case, the policy or measure is assumed to be **additional**.

[2] https://www.canada.ca/en/services/environment/weather/climatechange/canada-international-action/coal-phase-out/alliance-declaration.html

[3] https://poweringpastcoal.org/about/members

[4] https://beyond-coal.eu/data/

- **Is a policy or measure, that is not mentioned explicitly or implicitly in the impact assessment, explicitly addressing GHG emissions in the ETS sector?**
  A policy or measure is not part of the impact assessment but targets a reduction of GHG emissions in one or several sectors covered by the EU ETS. Examples are national initiatives towards phasing out coal-fired electricity generation, such as the CPF in the UK.

  If this is the case, the policy or measure is assumed to be **additional**.

3 Case Study: Estimating the impact of the UK carbon price floor on ETS emissions

As a strong national instrument with a likely significant impact on ETS emissions, which has not been taken into account in cap-setting for the third and fourth trading periods, the UK carbon price floor (CPF) represents a suitable case study for a policy instrument aimed at decarbonising electricity generation.

It should be noted this analysis was performed before the decision was made whether the UK would leave the EU-ETS. Although since 2021 the UK is not part of the EU-ETS anymore, the findings of this case study can still be applied to other member states.

This section develops two methods that can be used to estimate the extent to which an additional policy or measure has impacted the demand for allowances in the EU ETS, which in turn could be used to adjust the cap accordingly in order to avoid gross imbalances (see Section 4 for a discussion of compensation mechanisms). The methods developed here are most suitable for investigating the impact of additional policies and measures targeting fossil electricity generation, while the impact of an increase in or overachievement of, for example, EU-wide energy efficiency and renewable targets would resort to other methods (CEZ Group 2016; FTI-CL Energy 2017; ICIS / Tschach Solutions 2016).

The United Kingdom (UK) is one of the founding members of the "Power Past Coal Alliance" introduced above. On 1 April 2013 the UK introduced the CPF. The CPF was to act as an incentive for investments in low-carbon technologies, because EU allowance (EUA) prices at the time were too low to fulfil this function (standing at around 5 €/tCO_2 in 2013; Figure 1).

The CPF taxes fossil fuels used to generate electricity using a carbon price support (CPS) rate. The CPS acts as a supplement to the price of EUAs and is set on the basis of EUA price projections in such a way that the desired price floor (the sum of projected EUA prices and the CPS) is achieved. The price floor and support rate are announced three years in advance and not adjusted ex-post.

When the CPF was introduced, it was expected to increase annually to 30 GBP/tCO_2 by 2020. Due to the very low EUA prices, it was decided in 2014 to set the CPS at a maximum of 18 GBP/tCO_2 (about 25 €/tCO_2) for the period 2016 to 2020 in order not to weaken the country's economy against the competition from continental Europe. In 2016, the frozen price was extended until 2021. The resulting CPS rate stood at 4.94 GBP/tCO_2 between April 2013 and the end of March 2014, 9.55 GBP/tCO_2 between April 2014 and March 2015 and 18.08 GBP/tCO_2 from April 2015 onwards.

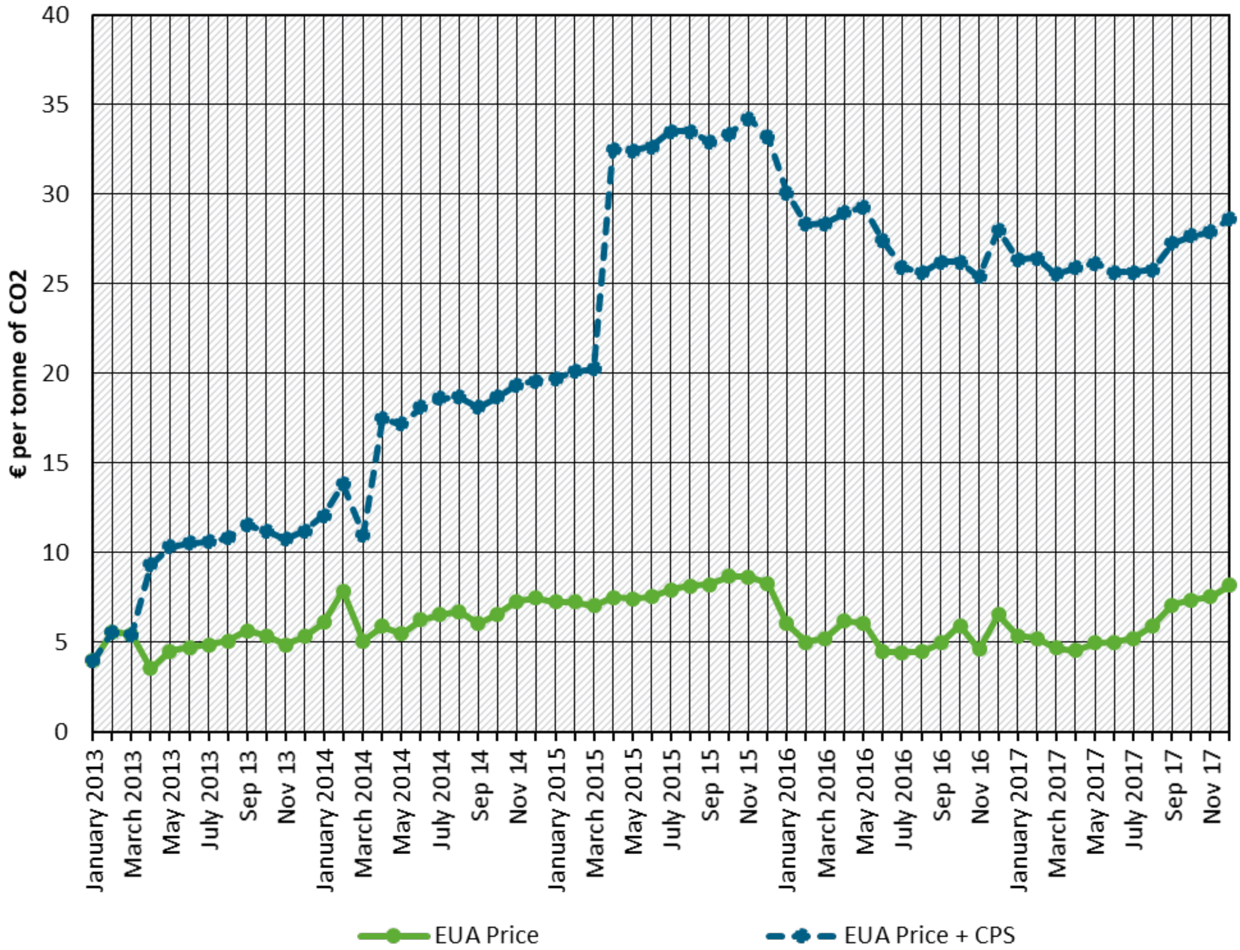
At its inception, the effect of the CPF/CPS was a doubling of the carbon price faced by the UK electricity sector, from around 5 €/tCO_2 to around 10 €/tCO_2. While carbon prices did not rise above 10 €/tCO_2 until the end of 2017 (the period under examination in the case study), the combined price effect of the EUA price and the CPS had climbed to 20 €/tCO_2 by 2014 and 35 €/tCO_2 by 2015, varying between 25 and 35 €/tCO_2 until the end of 2017.[5]

The CPS is collected by the Ministry of Finance. All revenue from the CPS is retained by the Treasury; in 2017 the Treasury collected 1 billion pounds in tax revenue from the CPF/CPS.[6]

[5] Note: Even though the CPS is constant, the two curves shown are not parallel. This is due to fluctuating exchange rates, as EUA prices are quoted in € and the CPS is charged in GBP.

[6]Sources: www.parliament.uk; www.gov.uk/government/uploads/system/uploads/attachment_data/file/293849/TIIN_6002_7047_carbon_price_floor_and_other_technical_amendments.pdf

Figure 1: CO2 price in €/tCO2 with and without CPF

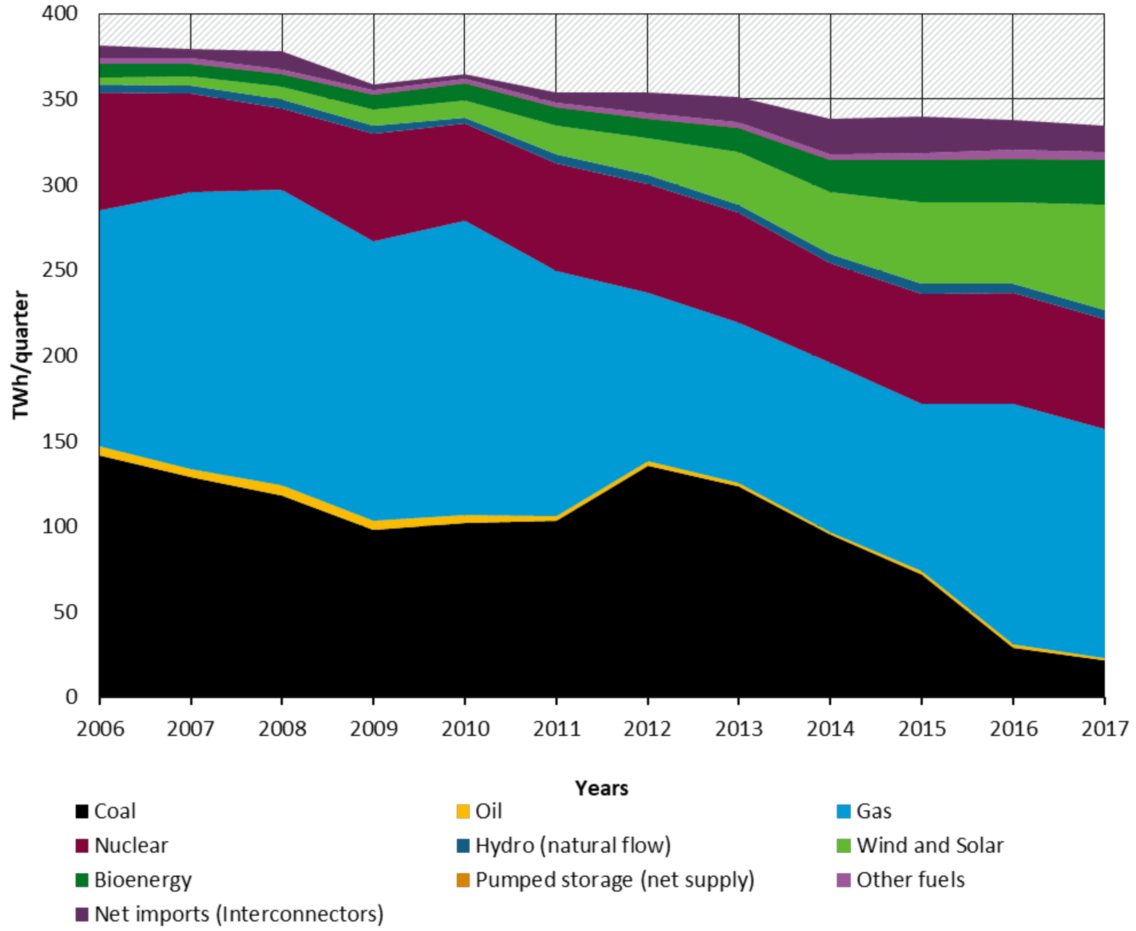


Source: Own illustration based on investing.com, general information on CPS, oanda.com

CO_2 prices play an important role in determining which power plants operate on the market. High CO_2 prices favour electricity generation from less carbon-intensive sources and lead to a situation where carbon-intensive sources (usually coal-fired power plants) no longer generate any electricity when demand for electricity is low or the share of renewables is high. Of course, other influencing factors exist, such as fuel prices or the power plant fleet, which will be explored in the next sections. In the long run, a sufficiently high and stable carbon price incentivises investment in clean energy sources (e.g. renewables).

Since the introduction of the CPF and in particular when the support rate was doubled in 2015, electricity generation from coal-fired power plants in the UK has declined dramatically (Figure 2). The amount of electricity generated using coal fell by around 83% between 2013 and 2017 and with 21 TWh in 2017 was about 102 TWh lower than in 2013. The decline in coal-fired power generation was compensated by gas-fired power generation (+40 TWh), wind and solar power (+31 TWh), a drop in demand (-13 TWh) and an increase in bioenergy (+11 TWh). The other electricity sources do not show any dramatic developments, although imports have also been increasing since 2011, and in 2014 and 2015 were significantly higher than in the other years of the period under consideration. Demand for electricity in the UK decreased by approximately 4%in the period under investigation (2013 – 2017).

Figure 2: Electricity generation mix by fuel source (UK) 2006-2017



Source: BEIS Energy trends section 5: Electricity (ET 5.1)

In this section, we want to answer the following question: How large is the emission reduction effect of the British CPF and how many allowances would have to be retired or cancelled to compensate its impact? In order to do this, we have to disentangle the impact of the CPF on emissions from other influencing factors during the study period. This question is relevant, also beyond the context of the UK, since floor prices are under discussion in several EU ETS countries.

The two approaches we develop in this section are suitable to estimate the reduction effect of additional policies and measures targeting fossil electricity generation. While they are used to simulate the specific impact of the UK CPF ex-post, it is also possible to use these approaches in order to estimate ex-ante the expected impact of planned or introduced policies or measures. In comparison to the ex-post exercise, additional assumptions would have to be made, e.g. for future fuel price developments.

We develop our first approach (Tier 1) in Section 3.1. It is a simplified calculation (carried out in Excel) compared to our second approach (Tier 2) developed in Section 3.2, which is based on a model of the European electricity market. While the second approach may have advantages regarding its precision in capturing the processes on the European electricity market (e.g. imports/exports of electricity), the simpler approach is developed with a view to using less computing power, as well as being lighter on the input data required (i.e. the goal was to use publicly available sources). Section 3.3 compares the two approaches in more depth. The results of both approaches are presented in Section 3.4.

3.1 Tier 1 Approach (Excel model)

The basis of our first approach (Tier 1) is an economic efficiency ranking (merit order curve) for all fossil fuel and biomass power plants in the UK including Northern Ireland. Power plants are ordered according to their electricity generation costs, which in turn depend on exogenous factors (CO_2 price, fuel prices, electricity demand, etc.). We estimate which power plants have the lowest electricity generation costs on the market (i.e. are the most economical ones) and which power plants are the most uneconomical and can no longer run at full capacity or are no longer needed at all.

Given the electricity demand, the maximum number of full load hours, the position of an installation on the merit order curve and based on an hourly evaluation, power generation and emissions per year for each power plant can be calculated. The total emissions of the power generation sector of the country (UK) are obtained by summing up the emissions of all power plants.

In order to be accessible to users without programming knowledge, the calculation in Tier 1 takes place in an Excel table.

Specific approach

In order to carry out a profitability ranking and set up the merit order curve, the costs incurred in a power plant to generate one unit of electricity (in this study one megawatt hour - MWh) are essential. The cost for generating one unit of electricity is called marginal costs and represents the price at which a power plant offers its electricity on the exchange. In the Tier 1 approach, this marginal cost is defined in a simplified form consisting only of two factors: fuel cost per MWh plus CO_2 cost per MWh.

The prices for the various fuels are entered exogenously into the tool. The efficiency of the respective power plant is used to calculate how much fuel it needs to generate one MWh of electricity. Just like the prices for fuels, the price for one tonne of CO_2 is also entered exogenously. The emission factors of the fuels and the efficiency of the power plant are used to estimate how much CO_2 the power plant in question emits per MWh of electricity generated.

It is important to take into account the fact that the demand for electricity varies over the course of one day and is also subject to seasonal variations. Instead of using an average annual demand as the basis for calculation, the Tier 1 approach uses a residual load profile (only the fossil power generation is included in the model via the load profile, renewable generation is not considered) that reflects daily and seasonal variations. This is important since in times of very high demand, less efficient power plants feed electricity into the grid. If these demand spikes were not taken into account, overall yearly emissions would therefore be underestimated.

Application to the UK CPF

The Tier 1 approach requires a robust database, which is described in detail in Appendix B.1. The core of the Tier 1 approach is a list of all relevant UK power stations (i.e. fossil fuels and biomass) covered by the EU ETS (including those situated in Northern Ireland) with a nominal capacity of more than 20 MW. The database mainly comprises hard coal and gas-fired power plants, but also oil, peat and waste power plants. The latter three, however, have only a very limited influence on the results due to their small number and low capacities.

We explicitly model the decommissioning of power plants and the conversion of power plants to biomass combustion or co-firing, but do not consider imports and exports in the calculation as the UK is an island and trade capacities with other countries are very limited. For continental European countries such a simplification would be more problematic.

Power plants require regular maintenance and are therefore not available for electricity generation 24 hours a day, 365 days a year. As a simplification, an average number of available full-load hours per day for all power plants was defined (in this case 19 hours). This is based on expert opinions that were used to calibrate the model. The hourly average net capacity of a power plant was then calculated by multiplying 19/24 with the net capacity of the respective power plant. This simplification was chosen over a more precise examination of the availability of power plants and their capacities in order to reduce demands in terms of computing power and guarantee the stability of the Excel tool, while having only a small impact on results, because we see in the model results that gas-fired power plants in particular cover the peak load, as would have been expected. This probably slightly underestimates the available capacity of the gas-fired power plants, as maintenance would most likely take place at times when the power plant would not be feeding electricity into the grid anyway, so that in practice maintenance times have little impact on the available capacity. In the model, however, the capacity is limited by the maintenance times. This effect is likely to be less pronounced for coal-fired power plants or all base-load power plants, as these continually operate and the maintenance period occurs at times when the power plant would feed into the grid.

The period between 2013 and 2017 is considered (the CPF was put in place in April 2013, cf. Figure 1), and two scenarios were calculated using the Tier 1 approach. One scenario with the UK CPF in place and one scenario without a minimum price on CO_2 emissions. For both scenarios exactly the same data basis was used, i.e. power plant fleet, fuel prices or residual load profile are the same. The only difference between the scenarios is the price to be paid for CO_2 emissions.

The residual load profile stored in the tool shows the hourly demand for electricity generated from fossil fuels. To keep the tool usable in Excel, for every month, the hourly demand is grouped, i.e. if the demand was within a certain range, it was rounded to a certain value. The tool then counts for every month how many hours are in each demand group. For each demand group it calculates which power plants feed in how much electricity, resulting in the emissions per demand group. The sum of all emissions of the demand groups then results in the emissions of the month under consideration. Results of the tool are given in monthly values (monthly electricity production from fossil sources, monthly CO_2 emissions).

3.2 Tier 2 Approach (Electricity market model)

PowerFlex EU is a bottom-up partial model of the European power sector that has been applied in a range of consultancy and research projects on a German and European level, such as analysis on flexibility options (Koch et al. 2015; Koch et al. 2017) or scenario development (Bundesregierung 2019; Öko-Institut et al. 2015; Ritter et al. 2019). The following description of the model's basic characteristics are taken from the in-depth documentation in Ritter et al. 2019.

PowerFlex EU calculates the dispatch of thermal power plants, feed-in from renewable energy sources, and utilisation of flexibility and storage options at minimal costs to meet electricity demand and reserve capacity requirements.

The model covers all ENTSO-E member states except Iceland and Cyprus. A transport model approach[7] is used to represent electricity exchange between countries. For each individual country, a homogeneous market area without grid constraints is assumed. Exchange between countries is limited by net transfer capacities (NTCs).

[7] In a transport model (as opposed to power flow distribution models), physical constraints regarding the distribution of power flows across meshed electrical networks are not taken into account.

The thermal power plant fleet is represented as aggregated vintage classes concerning age, fuel type, and technology of the individual plants.

The available electricity produced from run-of-river, offshore wind, onshore wind, and photovoltaic systems is represented by feed-in patterns in hourly resolution. The actual quantity of feed-in is determined endogenously, with the result that the available yield of fluctuating electricity can also be curtailed (e.g., in the case of negative residual load and insufficient storage capacity).

The model considers reservoir hydro plants and pumped hydro storage as flexibility options. They are modeled with the following parameter's set: pumping or charging capacity, storage capacity, electrical capacity of the turbine or discharging, the overall efficiency rate, and, in case of reservoir hydro plants, an hourly inflow profile.

Electricity demand is assumed to be inelastic. To derive demand profiles in hourly resolution, a standardized demand profile of the base year 2016 is scaled up using scenario-specific annual demand data.

Generation, transmission, and storage capacities are determined exogenously, i.e., the model does not endogenously calculate cost efficient investment or divestment pathways. The model assumes perfect foresight and calculates the cost-minimizing dispatch of given capacities in hourly resolution across a single year (8760 hours). In technical terms, it is formulated as a linear optimization problem, implemented in GAMS, and solved using the CPLEX solver.

Using an electricity market model to perform an ex-post analysis is an ambitious task, as the model necessarily represents reality in a simplified manner. The dispatch of power plants with either very low generation costs (nuclear energy, lignite) or very high generation costs (oil, biomass and other energy carriers) is determined by factors that are not taken into account in the optimisation process (e.g. technical inavailabilities, subsidies). For these power plants we assume a baseband dispatch profile that ensures that historical annual generation by energy carrier and country is met.

The remaining degrees of freedom are the hourly dispatch of natural gas and hard coal power plants (and the resulting CO_2 emissions), the utilisation of cross border transmission capacities, the dispatch of hydro storage facilities, and the curtailment of wind and PV generation (which plays only a very minor role during the observed time period).

3.3 Comparison of Tier 1 and Tier 2 approaches

Both modeling approaches aim at representing the fleet of fossil power plants in the UK at a similar level of detail, and therefore both require a certain amount of data, assumptions and computing power. Input data was harmonised wherever feasible. Some differences remain, either due to methodological differences or due to limited resources. Table 1 gives an overview on joint characteristics as well as differences. Details on the underlying data and assumptions for both approaches are presented in Appendix A.

Tier 1 puts a specific focus on fossil power plants inside the UK. It is well suited to represent this subset of a regional energy system. It focusses on the residual load generated by fossil fuels and does not take into account interactions with neighbouring countries. Tier 2 has a much wider focus and aims at representing the complete European electricity system. It is well suited to analyse cross-border interactions, interdependencies between fossil and renewable generation options, and utilisation of flexibility options, but it may have difficulties in assessing the behaviour of a small subset of power plants (e.g. coal power plants in the UK).

Table 1: Similarities and differences between Tier 1 and Tier 2

	Tier 1	Tier 2
Period	2013 – 2017	2014 - 2017
Geographical coverage	UK (incl. Northern Ireland)	Europe (excluding Iceland, Malta, Cyprus, Albania). UK incl. Northern Ireland.
Influencing factors on merit order curve	Fuel costs, CO_2 costs per MWh, conversion efficiencies	Fuel costs, CO_2 costs, variable operation & maintenance costs, conversion efficiencies
Temporal resolution	Hourly	Hourly
Power plant fleet	Platts + DUKES (only fossil plants >20MW)	Platts + DUKES (all plants)
Efficiency of power plants	Own internal assumptions (not harmonised)	Own internal assumptions (not harmonised)
Decommissioning of power plants	End of month	End of year
Power plant capacity available in the scenario without CPF	Same as in scenario with CPF	No decommissioning of coal-fired power plants
Biomass power generation	Power plant-specific reduction of capacity in both scenarios, depending on biomass share in the past. Biomass use itself is not considered	Fixed (annual quantities Eurostat), independent of CPF
Full load hours	79% availability for all power plants	90% availability for all dispatchable power plants
Import/Export	Not considered	Endogenous (result of the modeling, limited by NTCs)
Fuel prices, CO_2 price, support rate	Monthly data	Annual data
Load and renewable supply profiles	Hourly residual load profile for representative example year (source: Fraunhofer ISI), scaled to the respective year (source: Digest of UK Energy Statistics)	Hourly profiles for 2016 (source: ENTSO-E), scaled to annual load and generation for the respective year (source: Eurostat)
Emissions factors per fuel	Source UBA	Source UBA

Another difference between the two approaches is that the Tier 1 approach uses monthly prices, whereas the Tier 2 approach uses annual prices. Since fuel prices did not fluctuate significantly between different months of one year, this should only have a minor impact. Our results in Section 3.4 show that price fluctuations did not or only marginally impact the merit order curve in most years. The only exception is 2015, where a strong increase of the CPS occurred in April.

In addition to Tier 1 and Tier 2, a small number of highly simplified, stylised approaches were also developed and are briefly described and compared in Section 3.4.

3.4 Results and discussion

Generation and import of electricity

Figure 3 and Figure 4 show the power generated from hard coal and natural gas power plants between 2013 and 2017. The figures show statistical data of the Government Digital Service (Gov UK) [8] for the scenario with the CPF in place as well as the results from both modelling approaches.

The decrease in hard coal generation that took place between 2013 and 2017 is represented well by both modelling approaches, while both approaches overestimate hard coal generation in 2014. This effect decreases over time. In 2016 and 2017, hard coal generation is underestimated in Tier 2. Differences between statistical data and model results remain below 20 TWh/a (which – in relative terms – is a significant deviation only at the end of the observed time period, where hard coal generation has already decreased significantly).

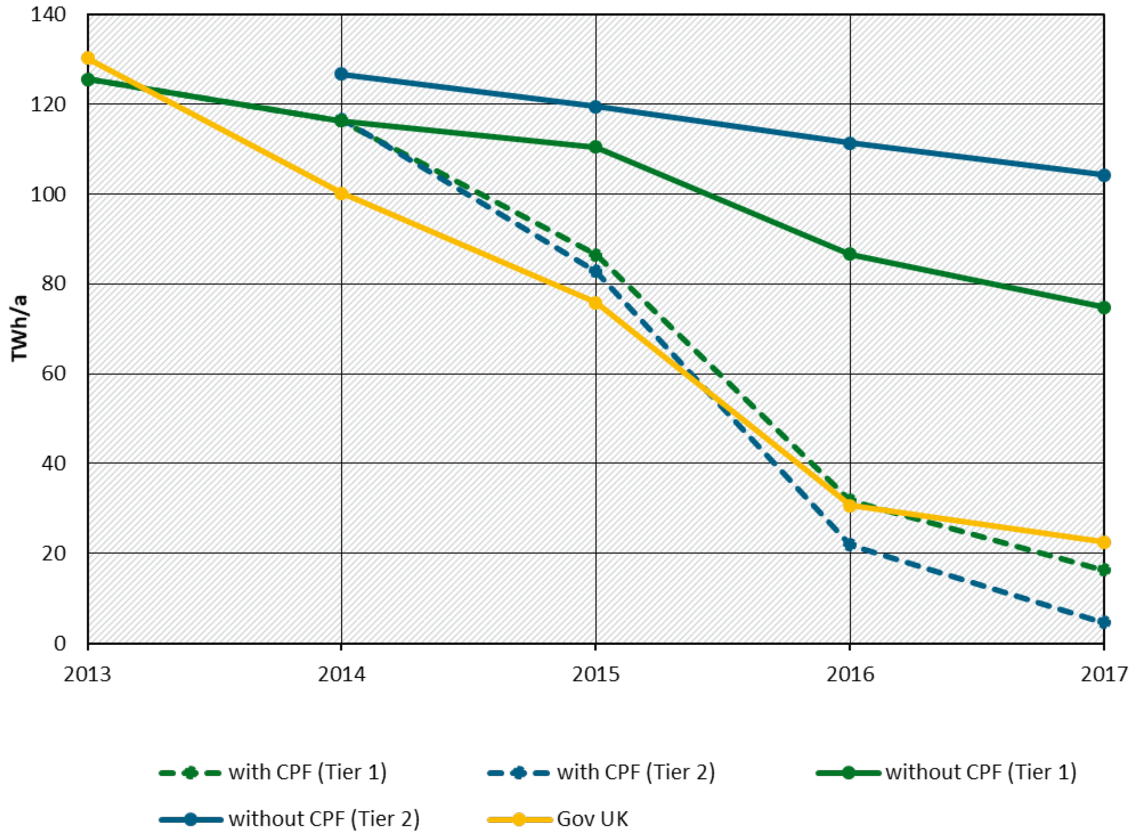
In the scenario without the CPF, the estimated amount of electricity generated from hard coal is consistently higher using the Tier 2 approach compared to Tier 1. The reason for this difference between the two approaches is the assumption made in Tier 2 that retirements of coal power plants after 2014 would not have occurred without the CPF in place. In contrast, in Tier 1 the power plant fleet is identical to the scenario with CPF, i.e. all affected power plants are decommissioned. This results in a difference in the set-up of the power plant fleet underlying the modelling in the scenario without CPF. In Tier 2, in particular, the available capacities of coal-fired generation in the scenario without the CPF are higher and, therefore a larger amount of electricity produced from coal-fired generation is estimated.

It is noteworthy that the CPF introduced in April 2013 does not have any effect until 2014, i.e. the low CPS rate of 4.94 GBP/tCO_2 from April 2013 to April 2014 had no impact on Tier 1 results (results of Tier 1 with and without CPF are identical for 2013). Since Tier 2 is only calculated from 2014 onwards, this effect cannot be examined using this approach. Also, in the remainder of 2014, the CPF does not affect the results in Tier 1, as the price differences are not large enough to change the national merit order. Only Tier 2 shows small effects in 2014, which are caused by UK coal-fired generation being replaced by imports (see Figure 5).

Both approaches show a decline of hard coal generation over time even in the scenario without the CPF. This can be explained by an increase of onshore wind generation capacity as well as a decreasing gap between coal and gas prices (see A.4).

[8] https://www.gov.uk/government/statistics/electricity-chapter-5-digest-of-united-kingdom-energy-statistics-dukes

Figure 3: Hard coal power generation

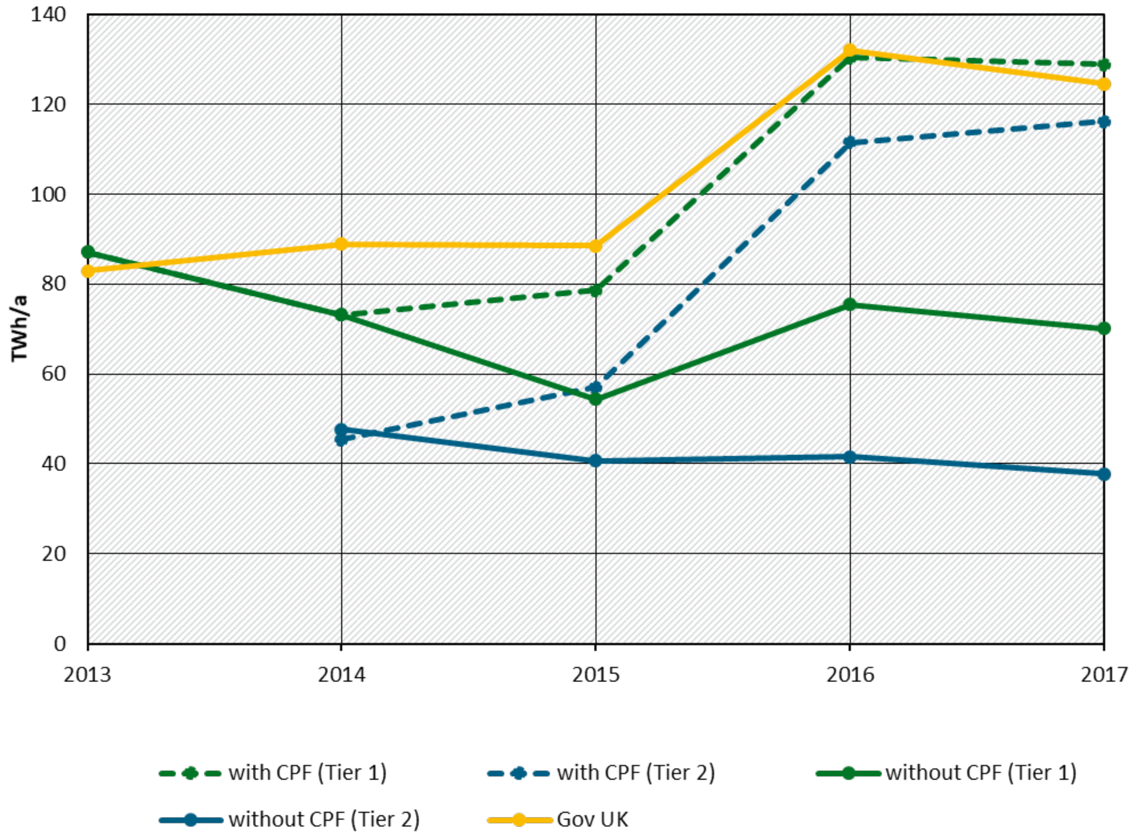


Tier 1 results in 2013 and 2014 identical for both scenarios
Source: Own illustration

The increase in the amount of electricity generated from natural gas that occurred in reality is represented well in the "with CPF scenario" of the Tier 1 approach. Tier 2 results show an underestimation of the amount of electricity generated from natural gas (Figure 4). The effect is largest in 2014 (40 TWh) and decreases over time. A reason for this deviation could be the overestimation of imports (see Figure 5).

When considering the whole period under investigation, the results of Tier 1 on the amount of electricity generated from coal and natural gas are very close to the actual historical data. While the amount of electricity generated by coal-fired power plants is slightly underestimated in 2013 and 2017, it is slightly overestimated in 2014 and 2015 and roughly met in 2016. For generation by gas-fired power plants, the Tier 1 approach overestimates production in 2013 and 2017, underestimates it in 2014 and 2015 and roughly meets it in 2016.

Figure 4: Natural gas power generation



Tier 1 results in 2013 and 2014 identical for both scenarios
Source: Own illustration

For the Tier 2 approach, on the other hand, it is not the case that the amount of electricity generated by the two sources sum up to the actual data over the whole period of estimation. In fact, the amount of electricity generated from gas-fired power plants is underestimated in all years, so is electricity generation from coal-fired power plants in 2016 and 2017. This means that in Tier 2 demand is assumed to be met by other sources. This is likely related to the fact, that in the Tier 2 approach, the integration of the UK into the European electricity market is modelled endogenously.

UK power plants operate in an international market, and an increase of short-term generation costs due to a national floor price leads to generation being shifted to neighbouring countries. This effect is limited by the availability of cross-border transmission capacities. The UK[9] has direct electrical connections to France, the Netherlands and Ireland. Figure 5 shows annual net imports from neighbouring countries into the UK for the years 2014-2017, as calculated by using the Tier 2 modelling approach as well as historical data.[10] With the CPF in place, net imports from all these sources add up to 25-28 TWh/a. This is close to the theoretical upper limit for annual imports, which is set at 31 TWh/a and determined by the availability of cross-border transmission capacities. In the scenario without the CPF, net imports are modelled at only about 50% of this value. Ireland (which has no direct electrical connections to other countries besides the UK) changes its role from being a net exporter (with the CPF in place) to being a net importer (without the CPF).

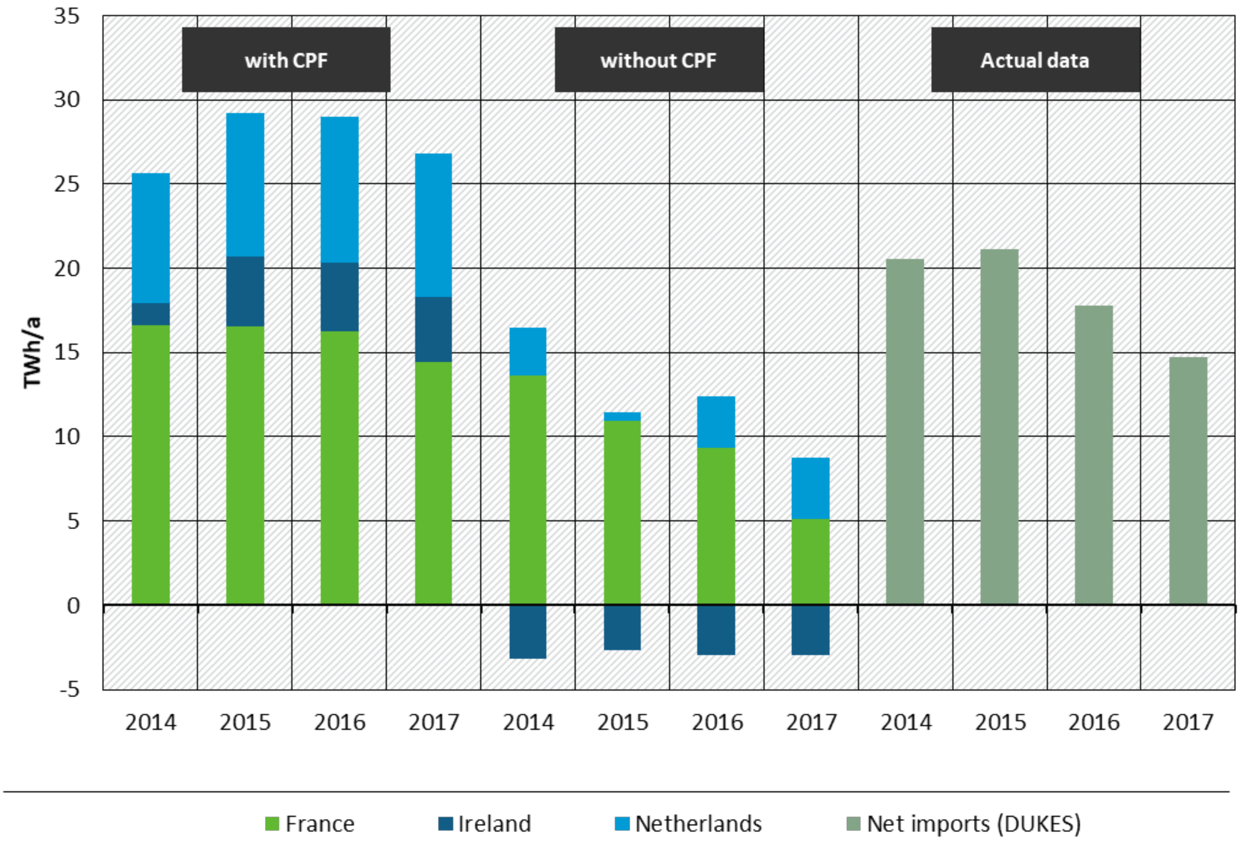
[9] The UK and Northern Ireland are treated as a single model region.

[10] Source: https://www.gov.uk/government/statistics/electricity-chapter-5-digest-of-united-kingdom-energy-statistics-dukes

Compared to historical data, imports in the Tier 2 approach are overestimated in the scenario with the CPF and are higher than in real data in all years. In contrast to the model results, the real data on imports show only a small reaction to the strong increase in the CPS rate in 2015.

One reason for the overestimation of imports in the Tier 2 approach may be the fact that the electricity grid is represented in the model in a highly simplified manner. Distribution of power flows in meshed grids are subject to restrictions that cannot easily be captured in linear optimisation models. Another reason may be the assumption that fuel prices are identical in all countries. Especially in the case of the UK, the availability of domestic natural gas resources may enable British power plant operators to procure natural gas at prices below global market prices. This would also explain the finding that both modelling approaches tend to underestimate natural gas generation and to overestimate coal generation.

Figure 5: Net imports of UK (Tier 2 model results and actual data). >0: import; <0: export



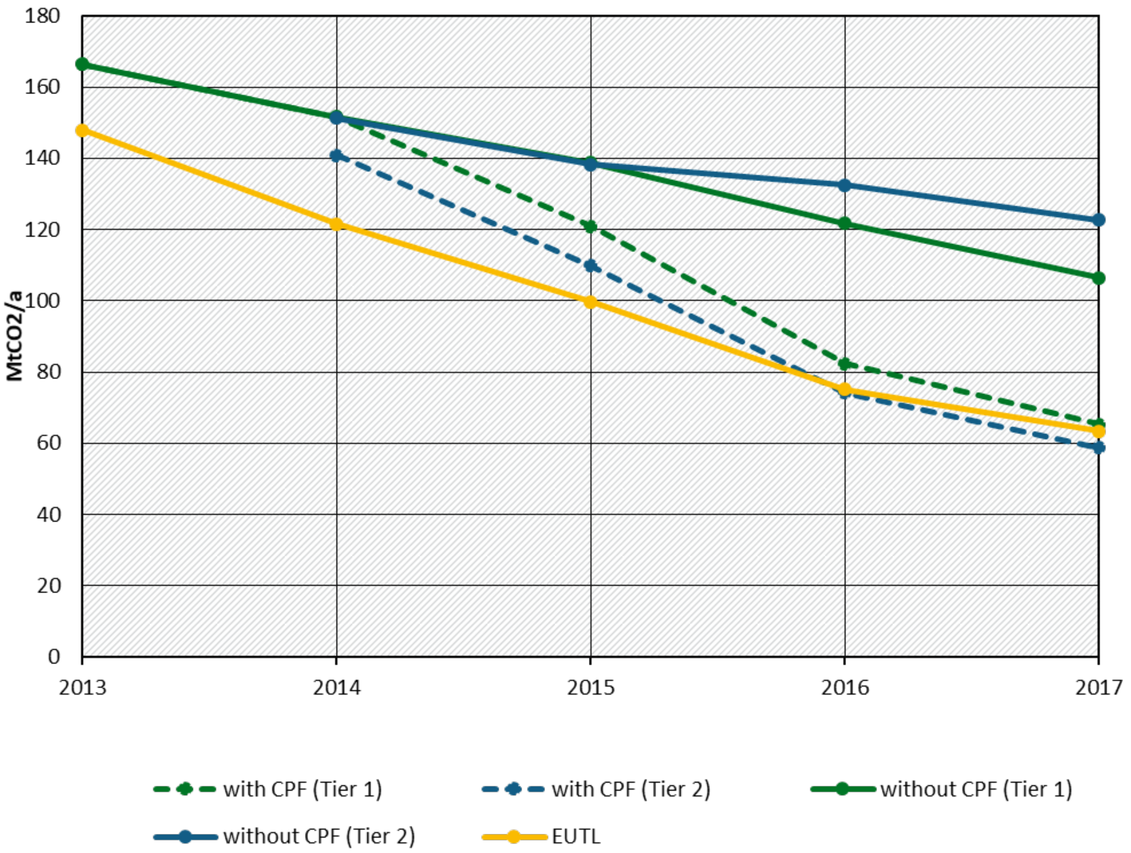
Source: Own illustration

Emissions

Figure 6 shows the development of CO_2 emissions in the UK between 2013 and 2017. It compares the results from both modelling approaches (Tier 1 and Tier 2) and also shows historical data for the case with CPF in place (EUTL). CO_2 emissions from electricity generation in the UK decreased by more than 50% from 145 Mt CO_2 in 2013 to 62 Mt CO_2 in 2017. This decrease is reflected in both modelling approaches. In both tiers, CO_2 emissions are overestimated in 2014 and 2015. The difference between model results and historical data decreases over time. This correlates with the overestimation of coal generation and underestimation of natural gas generation as shown in Figure 3 and Figure 4. The estimated emissions are lower using the Tier 2 approach compared to Tier 1 due to lower coal- and gas-fired generation and higher imports.

Both modelling approaches show a decrease in CO_2 emissions even without the CPF in place. These reductions amount to 45Mt/a (Tier 1) and 29Mt/a (Tier 2) between 2014 and 2017. This is due to an increase of wind generation capacity as well as increased hard coal prices. In case of Tier 1, the decommissioning of coal power plants and the retrofitting to biomass combustion also contributes to a decrease of CO_2 emissions in the baseline.

Figure 6: CO_2 emissions in UK



Source: Own illustration

For each tier, the effect of the CPF on CO_2 emissions can be calculated as the difference of emissions in the two scenarios with and without the CPF. This difference is shown in Figure 7. For Tier 2, Figure 7 also shows the effect of the CPF on EU-wide CO_2 emissions.

The effect of the CPF on CO_2 emissions in the UK increases from 0-10 Mt/a in 2014 to 40-65 Mt/a in 2017.[11] This correlates with the steady increase of the CPS rate during this period. As a comparison to the magnitude of the effect, studies put the impact of the increased EU-wide energy efficiency target for 2030 at 70-100 $MtCO_2/a$ (CEZ Group 2016; FTI-CL Energy 2017).

The Tier 2 approach systematically yields higher estimates than Tier 1. There are two reasons for this: Firstly, Tier 2 takes cross-border effects into account. This means that coal-fired power generation in the UK is replaced by an increase in electricity imports. Secondly, the available coal-fired generation capacity in the scenario without the CPF is higher in Tier 2 than in Tier 1.

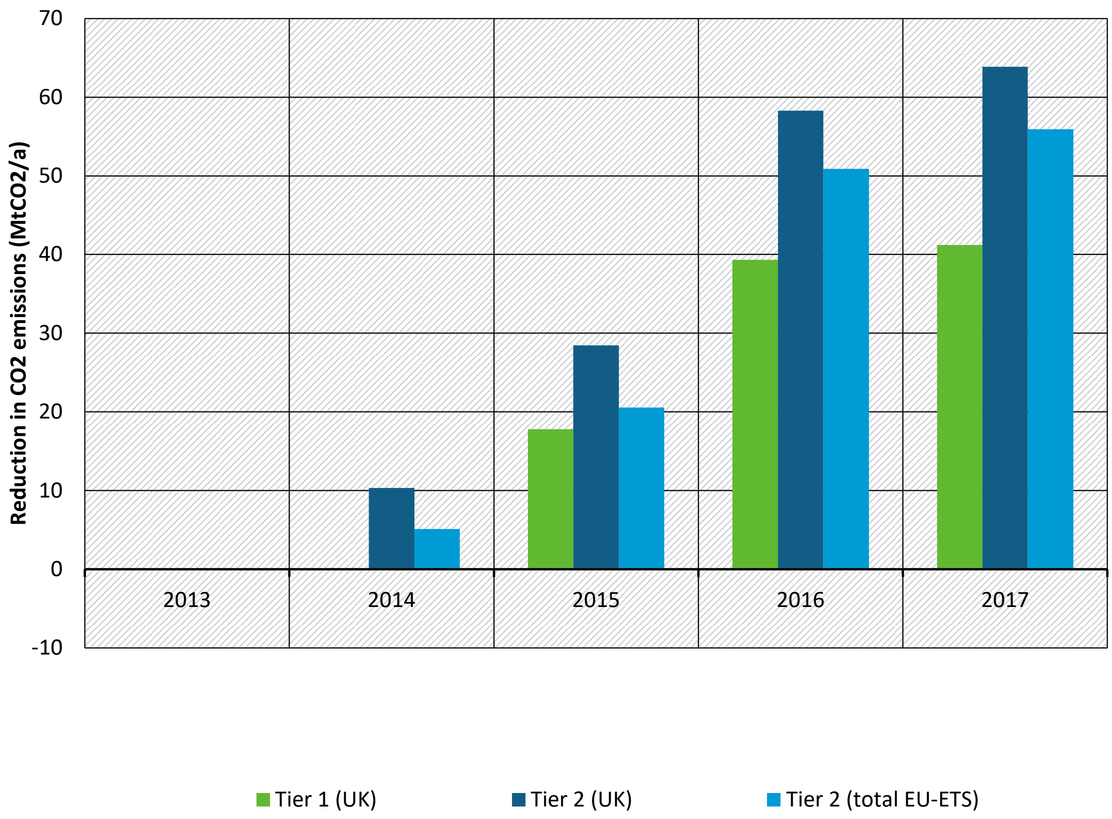
[11] In 2013, tier 1 shows no effect of the CPF due to the low CPS. In tier 2, the year 2013 has not been modelled.

In total, it can be expected that Tier 1 results represent a “lower bound” of the effect of the CPF (no cross-border effects, no decommissioning of power plants due to the CPF), and that Tier 2 results represent an “upper bound” (overestimation of cross-border effects, all observed decommissions attributed to the CPF).

As Tier 2 results show, the impact of the CPF on EU-wide CO_2 emissions is lower than on CO_2 emissions in the UK only (Figure 7). This rebound effect is caused by generation that is shifted from the UK to neighbouring countries. Tier 2 estimates that implementing the CPF induced additional CO_2 emissions outside of the UK of 5.2 Mt/a in 2014, increasing to 7.9 Mt/a in 2017. In 2017, this is equivalent to a relative rebound effect of 12.4% (additional emissions outside of UK relative to emission reductions in UK).

Across the complete period 2013-2017, the CPF is estimated to have reduced CO_2 emissions by between 98.3 Mt (Tier 1) and 132.5 Mt (Tier 2, including rebounds). This reflects an estimate of the potentially accumulated surplus in the EU ETS due to the CPF until 2017. This cumulated impact would further rise in the years from 2017 onwards until the emission reductions due to the CPF are no longer “additional” (i.e. until they would have been achieved by the EU ETS without the CPF) – or until the cap is adjusted in a way to account for the impact of the policy instrument.

Figure 7: Impact of the CPF on CO_2 emissions



Source: Own illustration

Comparison of the results with results of simpler approaches

Since both approaches applied above require an extensive database and exhibit a certain complexity, we explore two simpler, stylised approaches to estimate the impact of the UK CPF (or other additional policies and measures targeting electricity generation). The advantage of these simplified approach is that they are transparent, easy to implement and have low data requirements. However, they are more likely to lead to biased and misleading results.

Calculation of reduction impact based on historic emissions of decommissioned power stations

This approach looks at power stations that were decommissioned during the period of interest and emissions they have reported in the past (based on verified emissions in the EUTL). These historical emissions are used to form an estimate of the reduction impact of the CPF. Two options are explored: i) historical emissions in the last full year when it was in operation and ii) the average of the last five years of historical emissions of the power station. These historical emissions from all decommissioned power stations are then subtracted from the emissions of all power stations of the previous year. The result is an estimate of the emissions for the target year.

Figure 8 shows the results when this approach is applied to the UK CPF showing the option where the five-year average of historical emissions is used (Option ii above). While it exhibits a similar trajectory, this approach generally overestimates the actual emissions during the period under consideration and therefore underestimates the emission reductions that can be attributed to the CPF (compare "Decommissioned power plants" to "Emissions EUTL"). Except for 2014, this approach performs worse than the two approaches developed above. Especially in years where few power plants were decommissioned or when new gas-fired power plants were commissioned, this simple approach runs into problems. This also holds true when only one year of historical emissions is used (Option i above).

The main weakness of this approach is that it assumes no reduction in emissions if no power stations were decommissioned. This is a particular problem if there are shifts in the merit order curve that were not followed by decommissioning, e.g. due to an increase in CO_2 prices or the modernization of power plants.

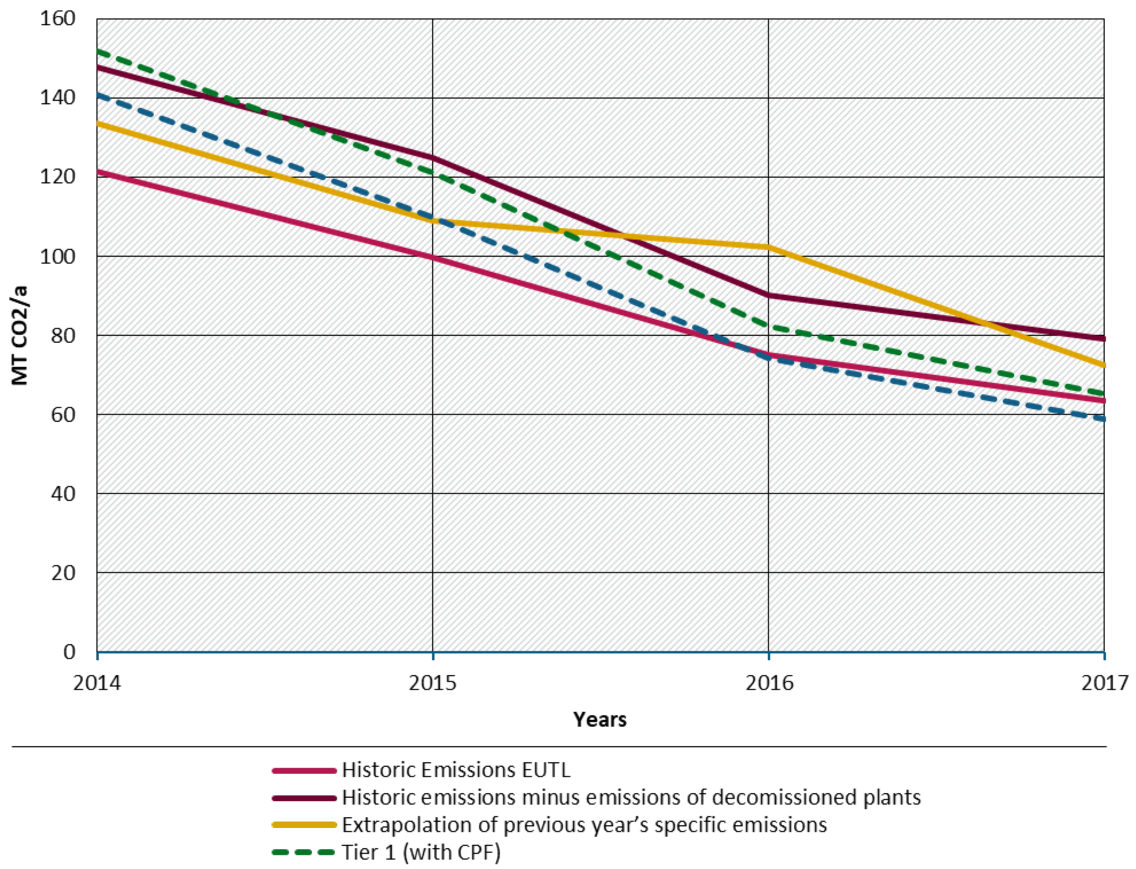
Calculation of future emissions based on specific emissions of the previous year

In a second simple approach, we multiply the electricity production of the current year with the specific emissions (emissions of all power plants divided by the amount of electricity generated in MWh) of the previous year. For the period under consideration, the emissions estimated using this approach are very close to actual emissions in 2014, 2015 and 2017 (compare "Specific emissions" with "Emissions EUTL" in Figure 8). In 2016, however, when there were major changes in the merit order curve and the emission factor had decreased significantly, the estimation shows a significant deviation.

While this approach provides useful results in years where there is little change in specific emissions compared to the previous year, it has major weaknesses when there are significant changes (e.g. shifts in the merit order curve). This is problematic, since estimations should be precisely when significant changes take place. Furthermore, the calculation is based on the electricity generated. While this information is available in this ex-post case study, ex-ante calculation would have to rely on projections.

Using specific emissions of the previous year to estimate future emissions works well as long as the merit order does not change significantly. In our ex-post example, the values are quite close to real figures because we could use real residual load. For an ex-ante analysis, one would have to estimate the residual load for the coming year.

Figure 8: Comparison of alternative approaches with historical data



Quelle: EUTL, own calculation

4 Compensation mechanisms

In Section 2 we discuss that there are several ways in which overlapping policies and measures have an impact on the demand for allowances in the EU ETS, e.g. an increase in or overachievement of EU-wide renewable energy or energy efficiency targets, as well as national policies or measures not reflected in the cap.

Independent of the source, additional emission reductions should be reflected in the supply of allowances, i.e. the cap. Otherwise the resulting imbalance between the demand and supply of allowances risks undermining the effectiveness and efficiency of the system. Several compensation mechanisms are already in place under the EU ETS. In general, these mechanisms can be divided in more long-term structural measures and short-term measures. It is also important to consider the time duration with which those mechanisms are applied and how they interact with each other (in particular at the end or beginning of a trading phase).

To reflect additional emission reductions in the cap in the long-term, adaptation of the cap resulting in a reduction of the overall amount of allowances available is the favourable option. Two factors influence the cap: i) the linear reduction factor and ii) the starting point from which this linear reduction is applied. An increase in the linear reduction factor (LRF) results in a stronger decline in available allowances year on year (a "steeper cap reduction path"). An adaptation of the starting point (also referred to as "re-basing") allows correcting the level of available allowances, while keeping the amount of allowances regularly taken out of the market on a yearly basis constant. Sooner or later, each additional emission reduction should be reflected in a structural adaptation of the cap – this also holds in the case of the UK CPF.

A rebasing of the cap in response to the UK CPF could start at the beginning of the fourth trading period (2021) at the earliest. The reduction of the cap level necessary to compensate for the long-term effect of the CPF should be in the order of the estimated impact of the CPF on ETS emissions, i.e. 40-65 $MtCO_2$/a (cf. Figure 7).[12] If this does not happen instantly, short-term mechanisms should be employed until this is the case.

The MSR – in place since 2019 - regulates the amount of allowances available to the market. If the surplus on the market (calculated by looking at the total amount of allowances in circulation since 2008 and the total demand, i.e. emissions, since that year) exceeds a certain threshold, allowances are placed into the reserve. Once the surplus available to the market is below a minimum threshold, allowances stored within the MSR re-enter the market. From 2023 onwards, there is an upper limit on the allowances that can be stored in the reserve, excess allowances in the reserve are invalidated. The MSR absorbs a share of the impact of the UK CPF on EU ETS emissions, as it is likely to have contributed to the overall allowance surplus in the EU ETS.

The MSR, however, will not be able to absorb allowances equivalent to the full emission impact of the UK CPF (cf. Burtraw et al. 2008; Kankaanpää 2020). First, the MSR does not react instantly to emissions imbalances, but with a lag. If lower demand for allowances due to interacting policy instruments leads to lower prices, emissions may rise elsewhere in the system, thus cancelling out the emission impact of the UK CPF. Second, the MSR does not absorb 100% of the emission surplus, but only a fraction. Therefore, the compensation by way of the MSR cannot be considered complete.

[12] If the UK were to leave the EU ETS as a consequence of Brexit, this would require a full re-basing taking into account total UK ETS emissions (likely using the current base period 2008-2012) and starting in the year when the UK would leave the EU ETS.

The ETS Directive for the fourth trading period (European Union (EU) 2018) stipulates a mechanism by which 5 years' worth of emissions can be cancelled from a country's auctioning budget in case fossil capacity is decommissioned (unilateral cancellation of allowances). However, as most capacities in the UK have already been decommissioned during the third trading period and with the UK possibly leaving the EU ETS after 2020, there is little potential for using this rule in order to compensate the estimated effect of the UK CPF.

5 Summary and Conclusions

While the EU Emissions Trading System (EU ETS) is one of the pillars of EU climate policy, it has always been part of a wider policy mix, including for example targets for renewable energy and energy efficiency at EU level, as well as national policies aimed at decarbonising the electricity sector. In order to ensure their desired contribution to emission reductions, it is crucial to take into account the interactions between those instruments and measures. In this paper, we focus on the interaction of national policies aimed at emission-intensive power generation with the EU ETS and their impact on ETS emissions. We develop and test two approaches to quantify the impact of the UK carbon price floor (CPF) on the EU ETS.

In a first step, we broadly describe the way in which additional policies and measures interact with the EU ETS and define in what case a given policy instrument or measure can be considered "additional" to the cap - in which case it should be reflected in the cap. In order to do so, an estimate of the reduction impact of the additional policy or measure is required.

In a next step, we use the UK carbon price floor (CPF) as a case study to develop two approaches (Tier 1 and Tier 2) that quantify the impact of an additional policy aimed at emissions-intensive electricity generation. The CPF was introduced in 2013 and significantly reduced emissions in the British power sector. Its impact was not taken into account in the setting of the ETS cap for the third and fourth trading periods (2013-2030), as it was adopted after the cap was set.

The first approach (Tier 1) is a simplified calculation (carried out in Excel) compared to our second approach (Tier 2), which is based on a model of the European electricity market. While the second approach may have advantages regarding its precision in capturing the processes on the European electricity market (e.g. imports/exports of electricity, for example increasing CO_2 emissions outside UK due to increased electricity imports), the simpler approach uses less computing power, as well as requiring less input data. The approaches further differ in their assumptions regarding the baseline scenario, in particular regarding whether or not decommissioning of power plants is attributed to the CPF. Results obtained under Tier 1 represent a "lower bound" to the impact of the CPF (no cross-border effects, no decommissioning of power plants due to the CPF), while those obtained under Tier 2 represent an "upper bound" (potential overestimation of cross-border effects, all observed decommissions attributed to the CPF).

In both approaches, we model the generation mix and CO_2 emissions for the years 2013-2017 for a scenario with and one without the CPF in place. The differences between these two scenarios is interpreted as the additional impact of the CPF. We estimate that the CPF induced reductions of CO_2 emission at around 10 Mt/a at its introduction rising to 40-65 Mt/a in 2017. The cumulated impact during the study period is estimated at around 100 Mt (Tier 1) and 130 Mt (Tier 2). Until the impact of the CPF is reflected in the ETS cap, this cumulated impact will continue to rise year-on-year leading to a supply surplus of EU allowances.

Since we look at the years 2013-2017 the estimated impact of the CPF using the two approaches can be compared to actual historical data. While estimated CO_2 emissions are close to historical values in 2016 and 2017, differences exist in particular during the first years of CPF operation. Both approaches overestimate generation from hard coal and underestimate generation from natural gas, which, in turn, leads to an overestimation of CO_2 emissions. In general, there are a number of effects that make it difficult to reproduce historical developments in modeling exercises. In our case study, a number of historical plants decommissions, ownership changes and fuel switches may not only have occurred due to economic reasons and cannot be reflected by either modeling approach. Other reasons may be the assumption of static efficiencies and availabilities, the differences between historical data model input data regarding fuel prices and wind and solar availability profiles.

With regard to the robustness of the approaches, it should be noted that as is true for any sort of modelling, our estimations rely on a number of assumptions. Ex-ante policy making is inevitably based on modelling and assumptions. This is also true for climate policy where decisions are made based on scenarios. Even ex-post estimations have to rely on assumptions to estimate the theoretical counterfactual. Therefore, our approaches are similar in their characteristics to other methods used in this field. The actual process of how these approaches could help towards compensating the impact of additional policies or measures, needs to still be determined. This process could contain elements of ex-ante projections and ex-post adjustments (Pöyry et al. 2017). As a first step, however, the approaches developed can provide an approximation of the magnitude of the adjustment necessary. Based on the estimated range of impact, an adequate course of action for compensation can be developed.

A compensation mechanism, namely the MSR, is currently implemented in the EU ETS. However, it is unlikely that the MSR absorbs the full impact of the UK CPF (or any other overlapping policy). This short-term measure should therefore only be an interim solution until more long-term measures, e.g. rebasing or adjusting the Linear Reduction Factor (LRF) or unilaterally cancelling allowances are taken.

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A Appendix: Underlying data and assumptions of Tier 1 and Tier 2

A.1 Power plant database

At the core of both approaches is a list of power plants from the Platts database. The database of the Tier 1 approach only contains EU ETS relevant installations in the UK including Northern Ireland i.e. data on fossil fuel power plants with a nominal capacity of more than 20 megawatts, whereas the full modelling approach (Tier 2) takes all power plants in Europe (excluding Iceland, Cyprus, Malta and Albania) into account, including wind parks, nuclear power plants or solar plants. Thus, the Tier 2 approach also considers wind and solar profiles (taken from ENTSO-E 2016), whereas this is not the case for Tier 1. These differences make it possible to calculate imports and exports in the Tier 2 approach and thus also to provide information on the extent to which the CPF has led to a shift in electricity production abroad and thus also to a shift in emissions abroad. Such an analysis is not possible in Tier 1, because imports are not considered.

The power plant database for Tier 1 has been determined on the basis of EUTL data that were matched with power plants from the Platts database. Excluded were power plants that only supply nearby industrial plants and thus do not feed into the grid. Small plants (< 20 MW) were also not included as they are normally not part of the EU ETS. Against the background that the power plant database dates from 2013 and due to the susceptibility to errors in matching, the data on which the model is based were held against the data of the Department for Business, Energy & Industrial Strategy (BEIS) (DUKES 5.10 of the respective year) and adjusted. This database contains all power plants in the UK that were in operation at the end of May of the respective year. It contains information on the fuel, location, installed gross capacity and the start of electricity generation. However, as the database does not contain any information on efficiency or net capacity, it cannot serve as the only input to calculation. The power plant efficiencies used in both approaches are based on internal assumptions that were not harmonised between Tier 1 and Tier 2.

For Tier 2, plants from the Platts database have been aggregated to vintage classes. Each vintage class contains power plants of a specific energy carrier, plant type, and similar age. The capacities of the vintage classes have been adapted to match information in the DUKES database.

A.2 Decommissioning and conversion of power plants

Between 2013 and 2017, there have been some significant developments in the UK power plant fleet, with some coal-fired plants being decommissioned, such as Cockenzie on 15 March 2013 or Longannet on 24 March 2016. The loss of coal-fired power plants was partly compensated by very efficient new gas-fired power plants, such as the Carrington gas-fired power station, which started operation in September 2016 with a capacity of slightly less than 900MW and an efficiency of 58 %. Both approaches take these changes in the power plant fleet into account, albeit in a different way. In the Tier 1 approach, power plants are considered closed from the month onwards that follows the month in which the closure officially took place. Similarly, new power plants were taken into account from the month following their commissioning. Due to technical restrictions of the modelling framework, decommissioning and new power plants in the Tier 2 approach were taken into account on an annual basis.

Another difference between the two approaches is the power plant fleet in the reference scenario. While in the Tier 1 approach, even in the reference scenario without the CPF, the power plants that were decommissioned during this period are assumed to be decommissioned all the same. This does not happen in the Tier 2 approach, i.e. in the reference scenario (no CPF) of the Tier 2 approach all power plants running in 2013 are available for the entire period. So far, the authors are not aware of any reliable study that deal in more detail with the reasons for the decommissioning of coal-fired power plants in UK between 2013 and 2017. However, a combination of the CPF, air pollution legislation and the fact that many coal-fired power plants had reached an age where they would have needed fundamental refurbishment seems to be a plausible explanation.

In the UK, some hard coal-fired power plants (e.g. Drax or Ferrybridge) were completely or partially converted to biomass power plants in the years under observation. We try to take temporary shutdowns into account on the basis of publicly available information. However, the available data on temporary closures are not fully available, which may mean that shorter closures are not taken into account. The co-firing of biomass in some coal-fired power plants is accounted for in the Tier 1 approach by reducing the capacity of the power plant by the annual percentage share of biomass in the combustion process. Example: For a coal-fired power plant with a capacity of 100 MW, which has fired 30% biomass in one year, the capacity is reduced by 30%, which would result in 70 MW of remaining coal capacity. The biomass data per power plant were downloaded from the European Environment Agency (EEA). This step ensures that electricity production from biomass is not part of the Tier 1 approach. For the Tier 2 approach, annual quantities of biomass co-firing were taken from EUROSTAT. Unlike in Tier 1, coal generation capacities have not been reduced accordingly. This results in an overestimation of available coal generation capacities.

In sum, the resulting database for both approaches contains the name of the power plant, the fuel, the gross capacity, the net capacity, emissions of the respective year according to the EUTL and the efficiency of the plant.

A.3 Emission factors

Table 2: Emission factors per fuel

Fuel	Tons per terajoule
Hard Coal	93.6
Brown Coal*	106.5
Peat	101.8
Oil	74.0
Natural Gas	55.9
Household rubbish	91.5

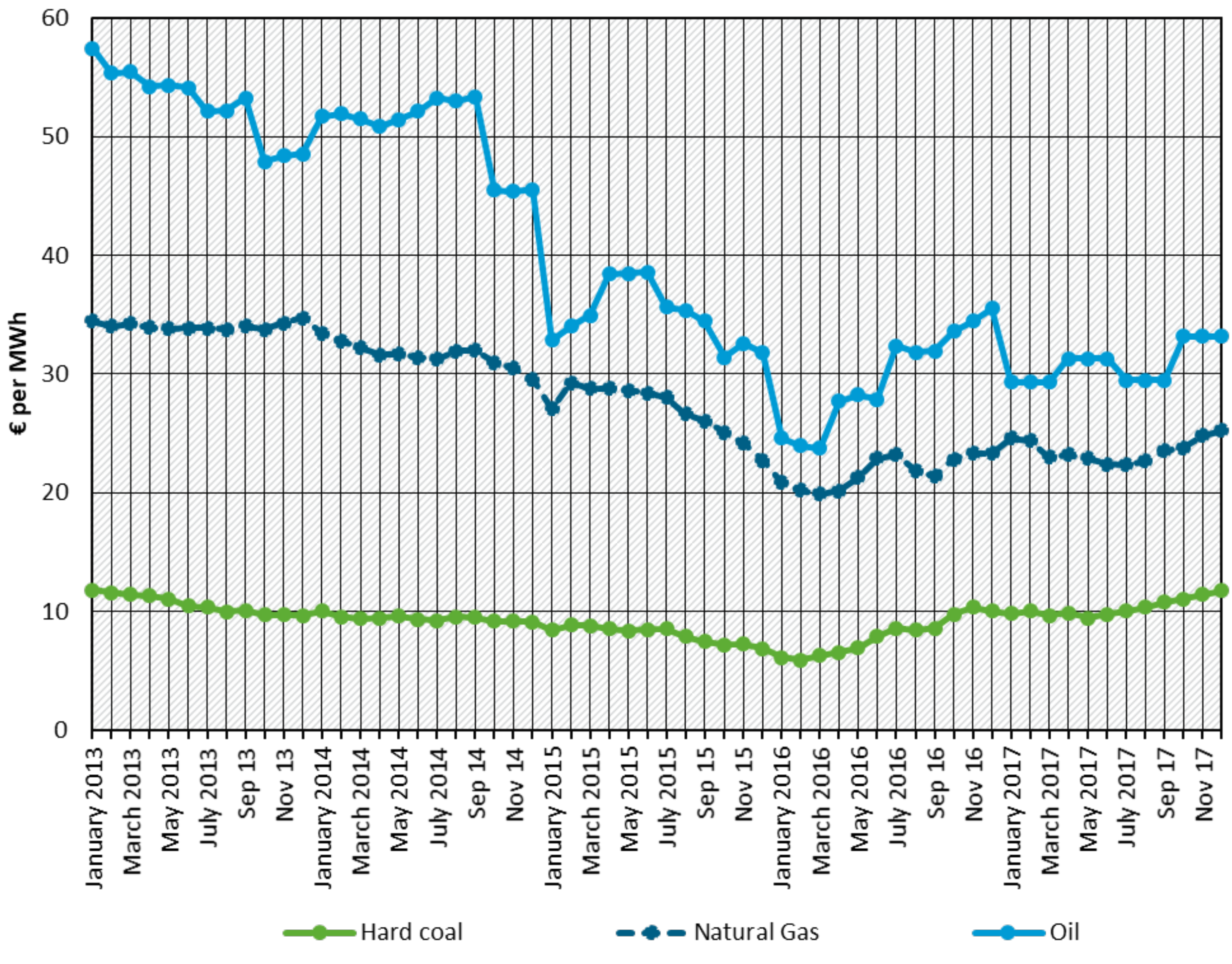
* Average
Source: CO_2-Emissionsfaktoren für fossile Brennstoffe, Umweltbundesamt

The emission factors for the Tier 1 approach are taken from the German Environment Agency (UBA) and present figures for Germany. A literature review showed that the emission factors differ only slightly between various sources. There are small deviations to the emission factors used in Tier 2, for hard coal (third decimal place), oil (second decimal place) and waste, where the deviation is somewhat larger, but is not significant due to the low capacity. Table 2 gives an overview on the emission factors used.

A.4 Fuel prices

In addition to the underlying power plant fleet and emissions factors, fuel prices also play a decisive role in determining the efficiency ranking of power plants (i.e. the merit order curve). Figure 9 shows the price development for hard coal, natural gas and oil for the relevant period. The oil price was most volatile during the period under consideration and showed a downward trend until the end of the first quarter of 2016, followed by a slight increase thereafter. Oil, however, plays only a minor role in electricity production due to its high price. The more relevant fuels are gas and coal, which showed less fluctuation in their prices. In step with the oil prices, gas prices generally show a downward trend over the relevant period, which means that gas-fired power generation became relatively cheaper than coal-fired power generation.

Figure 9: Fuel prices - Hard coal, Natural Gas, Oil - 2013 - 2017



Quelle: Own illustration based on eex.com and BEIS

However, the price gap between coal and gas remained quite wide. In December 2017, for example, at around €25 per MWh gas was still twice as expensive as hard coal, which cost just under €12 per MWh. This price difference cannot be compensated even by the usually much higher efficiencies of gas-fired power plants, so that without a CO_2 price, coal-fired power plants in the UK are more economical than gas-fired power plants in the period under consideration.

The prices for natural gas and hard coal are based on border prices for Germany[13] and are the same in both approaches. The assumption of uniform prices for all model regions may be one reason for the underestimation of gas consumption in UK (especially for gas, there are significant deviations in national prices). Nevertheless, an assessment of national prices for all European countries (which would have been required for the Tier 2 approach) would have been beyond the scope of this study, and identical price assumptions for both tiers facilitate the comparison between the two approaches. The prices for oil are taken from the UK Department for Business, Energy & Industrial Strategy (Table 3.2.1 Average prices of fuels purchased by the major UK power producers). Prices for waste and peat are estimated as no reliable data source is available. The effect on the results should be limited due to the very low capacities of these plants.

For fuel prices, EUA prices and the CPS rate - where available - average monthly and quarterly prices are used in Tier 1. Annual average prices were used for Tier 2 approach. We expect that this difference does not cause any major distortions in the results, as price fluctuations were too low to cause large monthly shifts in the merit order curve.

A.5 EUA prices and the CPS rate

Monthly EUA prices (ICE future prices for the December contracts) were downloaded from www.investing.com, prices ranged from 4.43 €/tCO_2 in July 2016 to 8.71 €/tCO_2 in December 2017 (Figure 1).

The Carbon Price Support (CPS) rate is 4.94 GBP/tCO_2 between April 2013 and the end of March 2014, 9.55 GBP/tCO_2 between April 2014 and March 2015 and 18.08 GBP/tCO_2 s from April 2015 (Figure 1).

The monthly exchange rates between Pound and Euro are taken from www.oanda.com.

In Tier 2, identical price assumptions where applied for all countries, with the exception of the CPS rate, which is only relevant for the UK.

A.6 Supply and load profile

Both approaches use different load profiles that provide the hourly electricity demand in the area under consideration for the relevant period. Since the Tier 1 approach only considers fossil power generation, the load profile was adjusted. This means that the amount of electricity generated by CO_2-neutral power plants was excluded. This results in a residual load profile that represents the hourly electricity demand that cannot be generated CO_2-neutral and must therefore be generated using fossil fuels.

Tier 1 uses a profile generated for use in the Enertile model from Fraunhofer ISI. It is calculated on the basis of a long-term demand average for all hours in a year and provides the hourly demand for electricity, as well as the coverage of the demand by the individual generation technologies. From this profile, only the residual load, i.e. the amount of electricity that has to be generated from fossil fuels, was considered. This residual load was then scaled to the actual

[13] Statistik der Kohlenwirtschaft e.V. (Statistik der Kohlenwirtschaft e.V., Hrsg.) (2018): Entwicklung ausgewählter Energiepreise. https://kohlenstatistik.de/17-0-Deutschland.html.

monthly residual load for the years 2013 to 2017. Data on the monthly electricity supply between 2013 and 2017 for the UK were used for scaling and were taken from BEIS (DUKES 5.3 and DUKES 5.6). These allow a differentiation between energy sources, which shows the supply of power from gas, coal and oil-fired power plants.

Tier 2 uses a load profile from ENTSO-E from 2016, which is not a residual load profile as in the Tier 1 approach, but a complete load profile, as all grid-relevant power plants are considered in this approach. This load profile was also scaled to the respective years. EUROSTAT electricity generation data were used for this adjustment.