Investigating a CO_2 Tax and a Nuclear Phase Out with a Multi-Fuel Market Equilibrium Model

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***Abstract*—We present an energy market equilibrium model that captures climate aspects, infrastructure constraints, fuel substitution, and market power à la Cournot in a single framework. The model represents the supply and transportation infrastructure, fuel transformation, power generation, and several demand sectors of fossil fuels, renewables and nuclear energy.**

We calibrate the model to market data from the year 2010, with a detailed representation of Europe and the rest of the world represented by continent. We analyze the impact of various regional and global CO_2 tax levels and the consequences of a nuclear phase out in Germany.

Our results illustrate that positive effects of regional CO_2 taxes can be largely undone through carbon leakage and that global CO_2 tax levels affect countries differently, dependent on factors such as the fuel mix and idle capacity in power generation. The regional fuel mix in Europe is affected less by a global than a local tax. Finally, Germany is well-connected to surrounding countries, and its potential to increase the use of renewables and import gas and electricity is high enough to compensate for a nuclear phase out.

***Index Terms*—Fuel substitution, environmental policy, market power, mixed complementarity problem.**

I. Introduction

STABILIZING the concentration of atmospheric Greenhouse Gases (GHG) to 450 parts per million is required to avert dramatic consequences [1]. Heat and electricity generation, together with the transportation sector, rely heavily on fossil fuels and account for nearly two-thirds of global carbon dioxide (CO_2) emissions [2]. Climate change mitigation efforts need to address these sectors, in order to achieve a considerable reduction in GHG emissions. Stern [3] was the first to provide an economic rationale for combating climate change, and numerous economists have weighed in on the matter since. However, translating broad guidelines into specific, explicit and detailed measures is challenging, and a sense of urgency is not unanimously shared. Politicians, economists and industry leaders argue about fair sharing of the burden and about the merits of systems such as cap–and–trade or carbon dioxide tax regimes.

International negotiations regarding a succession to the Kyoto protocol are proceeding (though at a glacial pace), and some countries and regions are in the process of introducing regional systems. The European Emission Trading System (ETS) was the first cap-and-trade system implemented to curb CO_2 emissions from within a larger region[1]. Unfortunately, in a world where the energy majors are global players, all initiatives to curb fossil fuel CO_2 emissions in one region might only shift activities to other regions, thereby penalizing countries with the best behavior. In contrast, continuous uncertainty and the threat of tighter future regulations also come at a price: Sinn [4] describes a "green paradox" where global climate change mitigation policies could induce fossil fuel producers to increase current supply in anticipation of reduced demand and lower prices in the future.

When analyzing electricity and fossil fuel markets, strategic behavior by the suppliers must be considered (cf., [5]–[7]). Market power exertion leads to higher end-user prices, relative to competitive supply costs. An emission tax also adds a price margin and may shift part of the rents from the suppliers to the coffers of the tax authorities. In addition, carbon leakage must be considered, as a CO_2 tax could shift emissions to regions with less or no regulation, and hence reduce global emissions less than anticipated.

Until recently, nuclear energy was touted by some as a means of creating a transition pathway to a low- or no-emission economy. The tragic disaster in Japan in March 2011, however, has cast doubt on investing in nuclear generation. Japan has announced a quicker phasing out of nuclear capacity[2] and Germany has shifted its stance on a moratorium of nuclear energy (once more)[3]. In many countries, renewable energy (from sources such as wind, solar, and biomass) is strongly subsidised, and global production from renewable sources is growing rapidly. However, starting at small amounts, the renewable share in total energy supply has not changed much in the last three decades (12.6% in 1980 to 13.0% in 2008). According to the IEA [8], this share will increase to between 14% and 16% in 2020.

There are many types of quantitative models for studying energy markets: Energy system models usually contain very detailed representations of demand, supply, and transportation and can provide insight into interactions in the energy system at many levels, including technology options and substitution effects. This level of detail comes at a cost, however, because these systems require many assumptions on matters such as investment behavior, technological progress, learning by doing, and price sensitivity. Keeping all parameters for these large models up-to-date is very time consuming. The models require extensive calculation time and market power is generally not considered. Furthermore, the results are usually projections, not multi-period equilibria. Examples of energy system models

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[1] http://ec.europa.eu/clima/policies/ets/index_en.htm

[2] nytimes.com/2012/01/07/world/asia/japan-new-limits-on-reactors.html

[3] www.bmu.de/atomenergie_ver_und_entsorgung/downloads/17_legislaturperiode/doc/47463.php

include the National Energy Modeling System developed by the US Energy Information Administration[4] as well as POLES and PRIMES, used for many energy related projections by the European Commission for the world [9] and the EU [10], respectively.

Partial equilibrium (sector) models, on the other hand, usually focus on only one fuel. Many have an equilibrium perspective and can accommodate Cournot market behavior. Examples include FRISBEE [11] and OilMod [12] for crude oil markets, World Gas Model [13] and GASMOD [14] for natural gas markets and COALMOD [15] for coal markets. Partial equilibrium models have been widely used to study matters such as competition policy and energy supply security [16]. Most sector models cannot capture fuel substitution explicitly, but some literature describes extensions accommodating fuel substitution in some sense. [17] present a non-linear demand function capturing fuel substitution due to relative price changes for a gas market model [18]. [19] incorporate endogenous gas supply into a competitive electricity market model in order to analyze reciprocal effects of bottlenecks in the European electricity and gas transmission grids.

Analyzing the consequences of environmental policies requires an integrated approach. This must also cover production, trade and consumption of all fuels, inter-fuel substitution, infrastructure, demand responses to price changes and market power aspects. In contrast to the partial equilibrium models, we include fuel substitution endogenously; however, we also explicitely include market power exertion by some players, differing from the common energy system models. Our approach hences aims to bridge these two modelling approaches. We apply our model to analyze the impact of various regional and global CO2 tax levels and the consequences of a nuclear phase out in Germany.

The remainder of this article is structured as follows: In the next section (II) we present a multi-fuel equilibrium model with fuel transformation and substitution in the demand sectors. Section III describes the input data set. Section IV discusses results from three case studies, covering regional and global CO_2 taxes, and a German nuclear phase out.

II. A Multi-Fuel Market Equilibrium Model

The model covers all parts of the supply chain including upstream production, midstream transformation, transportation and trade, and downstream consumption. Production and trade activities are the responsibility of the suppliers. Figure 1 shows a two-country example of the relations and interactions included in our approach. Transformation infrastructure (refineries, power generation) and transportation infrastructure (pipelines, ships, LNG import and export terminals and long haul trucks) are modeled as profit maximizing price-taking service providers. We implement restrictions on carbon dioxide emissions, either through taxes or ceilings, imposed by a carbon dioxide permit auctioneer based on willingness to pay. Consumption is modeled through inverse demand curves by sector. The data sets are completely parameterized, hence the level of detail is virtually unlimited. More details on data

[4]www.eia.doe.gov

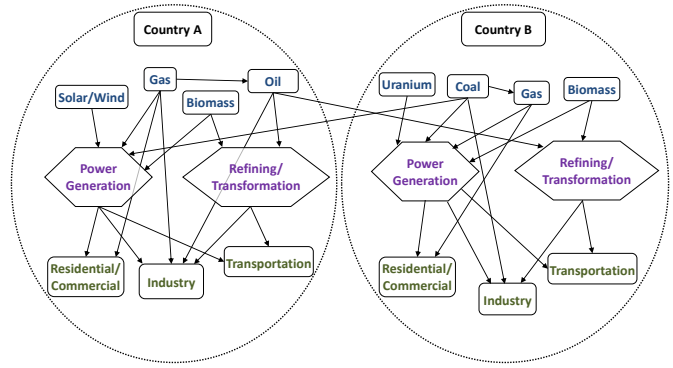

Fig. 1. Supply chain illustration

are presented in the next section (III). First we clarify the notation used. Then, the optimization problems for suppliers, transportation arc operators, transformation operators, and the GHG emission auctioneer are presented.

Among different agents the notation used is as consistent as possible. All dual variables are lower-case greek letters. τ stands for duals on capacity constraints and μ for CO_2 emission constraints. Parameters are succinct, self-explanatory abbreviations. For subsets (of arcs and refineries) the superscript $^+$ ($^-$) refers to elements that contribute positively (negatively) to the mass balance at a specific node (see Eq. 3).

We introduce the set of constraints $m \in M$ to represent fuel restrictions related to matters such as peak load electricity or mandatory shares of bio-ethanol in gasoline. We refer to them as the generation mix or fuel mix constraints. All decision variables of suppliers are denoted by q^X (where X is replaced by an appropriate letter to indicate the activity), and the service providers decision variables are written as f^X (where X denotes the service). Prices connected to market-clearing constraints are denoted by p^X.

The supplier

The supplier maximizes profits from selling fuels, subtracting costs for production, transport, transformation and emission permits. Losses during production, transportation and transformation are considered in the mass balance constraint. For each fuel-node combination, suppliers can be Cournot players ($cour^S_{s,n,e} = 1$) or compete perfectly ($cour^S_{s,n,e} = 0$). In the implementations we used the production cost functions proposed by Golombek [20].

$$\begin{aligned}
\max_{\substack{q^P,q^A\\ q^C,q^D}} \sum_{\substack{n\in N\\ e\in E}} \Bigg(\sum_{d\in D} \Big[& cour_{s,n,e} \cdot \Pi^D_{n,d}(\cdot) \\
& + (1 - cour_{s,n,e}) \cdot p^D_{n,d} \Big] \cdot eff^D_{n,d,e} \cdot q^D_{s,n,d,e} \\
& - cost^P_{s,n,e}(q^P_{s,n,e}) \\
& - \sum_{(n,k)\in A} p^A_{n,k,e} \cdot q^A_{s,n,k,e} - \sum_{(n,c)\in C} p^C_{n,c,e} \cdot q^C_{s,n,c,e} \\
& - \left(p^G_n \cdot ems^P_{s,n,e} \cdot q^P_{s,n,e} + \sum_{d\in D} p^G_n \cdot ems^D_{d,e} \cdot q^D_{s,n,d,e} \right) \Bigg)
\end{aligned} \quad (1)$$

Sets and Mappings

$n, k \in N$	... nodes
$r \in R$	... regions
$n, k \in N_r$	... node-to-region mapping
$r \in R_n$	... region-to-node mapping
$s \in S$	... suppliers
$d \in D$	... demand sectors
$e, f \in E$	... fuels
$m \in M$	... generation mix constraints
$\tilde{e}, \tilde{f} \in \tilde{E}_m \subset E$	... fuels with generation mix constraints
$a(n, k, e) \in A$	... node-to-node arc mapping
$k \in A_n^+$	... start nodes k of inflow arcs ending at node n
$k \in A_n^-$	... end nodes k of outflow arcs starting at node n
$c(n, e, f) \in C$	... fuel transformation technology
$\tilde{c} \in \tilde{C}_m \subset C$	... transformation technologies satisfying constraint m
$f \in C_c^+$	... output fuels obtained from refinery
$e \in C_c^-$	... input fuels for refinery

Functions and Parameters

$cost^P_{s,n,e}(\cdot)$	... production cost function
$cap^P_{s,n,e}$	... gross production capacity
$loss^P_{n,e}$	... loss rate during production
$ems^P_{s,n,e}$	... emission rate during production
$cour_{s,n,e}$	... market power parameter
$trf^A_{n,k,e}$	... tariff for fuel transportation along arcs
$cap^A_{n,k,e}$	... capacity of arc
$loss^A_{n,k,e}$	... loss rate during transportation of fuel
$ems^A_{n,k,e}$	... emission rate during transportation of fuel
$conv^C_{c,f}$	... transformation efficiency for output fuel
$trf^C_{n,c}$	... input fuel specific transformation tariff
$cap^C_{n,c}$	... transformation capacity (input restriction)
$ems^C_{c,e}$	... emission rate during transformation of (input) fuel e
$shr_{n,m}$	... minimum share of fuels included in constraint m
$quota^{glob}$	... global emission quotum
$quota^{reg}_r$	... regional emission quota
$quota^{nod}_n$	... nodal emission quota
tax^{glob}	... global emission tax
tax^{reg}_r	... regional emission tax
tax^{nod}_n	... nodal emission tax
$\Pi^D_{n,d}(\cdot)$	... inverse demand curve
$int^D_{n,d}$	... intercept of inverse demand curve
$slp^D_{n,d}$	... slope of inverse demand curve
$eff^D_{n,d,e}$	... sector specific fuel efficiency
$ems^D_{d,e}$	... emission rate during fuel use

Variables

$f^A_{n,k,e}$	... aggregate quantity transported by arc operator
$f^C_{n,c,e}$	... aggregate input quantity into transformation
$f^G_{n,g}$	... aggregate emission volume
$q^P_{s,n,e}$	... quantity produced by supplier
$q^A_{s,n,k,e}$	... quantity transported by supplier
$q^C_{s,n,c,e}$	... quantity put into transformation by supplier
$q^D_{s,n,d,e}$	... quantity sold by supplier to demand sector
$\alpha^P_{s,n,e}$	... dual of production capacity constraint
$\beta_{n,m}$	... dual of generation mix constraint
μ^{glob}	... dual of global emission constraint
μ^{reg}_r	... dual of regional emission constraint
μ^{nod}_n	... dual of nodal emission constraint
$\phi_{s,n,e}$	... dual of mass-balance constraint
$p^A_{n,k,e}$	... market-clearing price using arc capacity
$p^C_{n,c,e}$	... market-clearing price using transformation capacity
$p^D_{n,d}$	... efficiency corrected energy price for demand
p^G_n	... market-clearing price for emissions
$\tau^A_{n,k,e}$	... dual of transportation capacity constraint
$\tau^C_{n,c}$	... dual of transformation capacity constraint

$$\text{s.t.} \quad q^P_{s,n,e} \leq cap^P_{s,n,e} \quad (\alpha^P_{s,n,e}) \quad \forall\, n \in N, e \in E \tag{2}$$

$$\begin{aligned}(1 - loss^P_{n,e}) \cdot q^P_{s,n,e} - \sum_{d \in D} q^D_{s,n,d,e} \\ + \sum_{f \in C_c^+} conv^C_{c,f} \cdot q^C_{s,n,c,f} - \sum_{c \in C} q^C_{s,n,c,e} \\ + \sum_{k \in A_n^+} (1 - loss^A_{k,n,e}) \cdot q^A_{s,k,n,e} - \sum_{k \in A_n^-} q^A_{s,n,k,e} = 0 \\ (\phi_{s,n,e}) \quad \forall\, n \in N, e \in E\end{aligned} \tag{3}$$

Next, we give the optimization problems for the three service providers that are in charge of efficiently allocating scarce capacities. By assumption, all service operators are price-taking profit maximizers. First, we present the (transportation) arc operators. Second, the transformation operators, and third, the CO_2 emission permit auctioneer.

The arc operator

There are many transportation options for fuels. The formulation for the arc operator must capture crude oil tankers, long-haul truck and train transport of coal, the power transmission grid as well as gas and oil pipelines and gas liquefaction, and LNG shipping and regasification. Emissions induced by transportation are assigned to the starting node of the arc. The minimum charge for transportation is set by a fixed tariff. Profits may result when capacities are binding and market clearing prices include congestion charges.

$$\max_{f^A} \left((p^A_{n,k,e} - trf^A_{n,k,e}) \cdot f^A_{n,k,e} - p^G_n \cdot ems^A_{n,k,e} \cdot f^A_{n,k,e} \right) \tag{4}$$

$$\text{s.t.} \quad f^A_{n,k,e} \leq cap^A_{n,k,e} \quad (\tau^A_{n,k,e}) \tag{5}$$

The transformation operator

The formulation of the transformation operator must capture a variety of diverse processes including crude oil and biofuel refining, and electric power generation. Some transformation types may take more than one input fuel; others may produce multiple output fuels. The minimum charge for transformation is set by a fixed tariff. Profits may result when capacities are binding and the market clearing price includes a congestion charge.

$$\max_{f^C} \sum_{e \in C_c^-} \left((p^C_{n,c,e} - trf^C_{n,c}) \cdot f^C_{n,c,e} - p^G_n \cdot ems^C_{c,e} \cdot f^C_{n,c,e} \right) \tag{6}$$

$$\text{s.t.} \quad \sum_{e \in C_c^-} conv^C_{c,e} \cdot f^C_{n,c,e} \leq cap^C_{n,c} \quad (\tau^C_{n,c}) \tag{7}$$

The generation mix constraints (denoted by $m \in M$) provide minimum shares for subsets of input fuels ($\tilde{e} \in \tilde{E}_m$) in specific subsets of the transformation units $\tilde{C}_m \subseteq C$.

$$\sum_{\substack{(c,e) \in C \\ \tilde{f} \in \tilde{E}_m}} shr_{n,m} \cdot conv^C_{c,\tilde{f}} \cdot f^C_{n,c,e} \leq \sum_{\substack{(\tilde{c},e) \in \tilde{C}_m \\ \tilde{f} \in \tilde{E}_m}} conv^C_{\tilde{c},\tilde{f}} \cdot f^C_{n,\tilde{c},e} \quad (\beta_{n,m}) \quad \forall\, n \in N, m \in M \tag{8}$$

The emission auctioneer

The emission auctioneer allocates CO_2 emission quota. There can be multiple constraints on global, regional or nodal levels. In addition, carbon taxes can be introduced. In fact, applying such taxes would provide lower bounds to equilibrium prices for the CO_2 emissions.

$$\max_{f^G} \sum_{n \in N} \left(p_n^G - tax^{glob} - \sum_{r \in R_n} tax_r^{reg} - tax_n^{nod} \right) \cdot f_n^G \quad (9)$$

$$\text{s.t.} \quad \sum_{n \in N} f_n^G \leq quota^{glob} \quad (\mu^{glob}) \quad (10)$$

$$\sum_{n \in N_r} f_n^G \leq quota_r^{reg} \quad (\mu_r^{reg}) \quad \forall\, r \in R \quad (11)$$

$$f_n^G \leq quota_n^{nod} \quad (\mu_n^{nod}) \quad \forall\, n \in N \quad (12)$$

The formulation can easily be generalized to differentiate between multiple GHG.

Market clearing

Market clearing conditions (m.c.c.) link the problems of the individual players together in a single equilibrium framework. The first m.c.c. is for arc capacity, the second for transformation capacity and the third for CO_2 emission permits.

$$\sum_{s \in S} q_{s,n,k,e}^A = f_{n,k,e}^A \quad (p_{n,k,e}^A) \quad \forall\, (n,k) \in A, e \in E \quad (13)$$

$$\sum_{s \in S} q_{s,n,c,e}^C = f_{n,c,e}^C \quad (p_{n,c,e}^C) \quad \forall\, n \in N, e \in E, c \in C \quad (14)$$

$$\sum_{n \in N, e \in E} \left(\sum_{s \in S} ems_{s,n,e}^P \cdot q_{s,n,e}^P + \sum_{s \in S, d \in D} ems_{d,e}^D \cdot q_{s,n,d,e}^D + \sum_{k \in A_n^+} ems_{n,k,e}^A \cdot f_{n,k,e}^A + \sum_{c \in C} ems_{c,e}^C \cdot f_{n,c,e}^C \right) = f_n^G \quad (p_n^G) \quad \forall\, n \in N \quad (15)$$

Final demand

An inverse demand function is used for each consumption sector. The fuel-sector specific efficiency factor $\mathit{eff}_{n,d,e}^D$ allows to address the characteristics of different fuels satisfying demand in the same sector.

$$int_{n,d}^D - slp_{n,d}^D \cdot \left(\sum_{s \in S, e \in E} \mathit{eff}_{n,d,e}^D \cdot q_{s,n,d,e}^D \right) = p_{n,d}^D \quad \forall\, n \in N, d \in D \quad (16)$$

We assume that profit maximization functions of all agents are concave and twice differentiable. All feasible regions are specified by affine inequalities and linear equality conditions. For such problems, Karush-Kuhn-Tucker (KKT) conditions are necessary and sufficient for optimal solutions [21]. The KKT are derived for the model and implemented as a mixed complementarity problem using GAMS. Because space is limited, the KKT are not included in this paper.

III. Input data

The model is fully parameterized in terms of regional detail, energy and fuel categories, energy transformation options and demand sectors. Similar data sources are used here as in [12], [15], [22], [23]; updated versions were used whenever available.

In this paper we implement a single period model with emphasis on Europe and the main energy categories. This means that all European countries are included separately, whereas other world regions are included by major region or continent. Fuel categories comprise coal, petroleum products, natural gas, nuclear power, hydropower, biofuels, and other renewables.

A model that covers so many aspects of all important fuels requires substantial amounts of data, such as capacities of transportation infrastructure, costs, loss rates and efficiencies, as well as reference values for production, consumption, trade and market prices. Internal consistency of the data is even more important with this model than for sector models. For instance, in a single fuel sector model using either short-term operational costs or long-run marginal costs may yield reasonable model results. However, in a multi-fuel model, the different cost characteristics of the various fuels can impede the consistency of the solution. It is much more important to consider long-run marginal costs, as well as other factors affecting the behavior of producers and traders that ultimately determine the supply of fuels. There are also considerations related to strategic behavior in infrastructure investment decisions as well as contracting, exploration and extraction. As energy market researchers, we are aware of many of these considerations, but due to a lack of available, reliable and consistent information, we have to use approximations for some of the data.

In this paper, we focus on the interaction of the fossil fuel markets. For other non-fossil energy sources, we assume capacities equal to reference output volumes adjusted for transformation losses. Low production and transformation costs ensure that they are used to their full capacity. Energy markets are very dynamic and we believe that we can gain the most insight into the market situation and developments by investigating the most recent year for which data is available. Hence, the case studies are based on the year 2010. As a reference for the outcomes of production and consumption volumes, net trade, power generation and wholesale market prices we use as much data as possible from BP [24], IEA [25], [26], [27], [28], and Eurostat[5]. Infrastructure data (i.e., capacities, costs and losses related to transporting and transforming fuels) originate from various sources. ENTSO-G[6] and ENTSO-E[7] are valuable sources for natural gas and electricity transportation capacities, and GIIGNL [29] is a valuable source for natural gas liquefaction and regasification capacities. Pipeline data for oil originate from various websites.[8] To determine the inverse demand curves, price elasticities were used based on [30] and

[5] http://epp.eurostat.ec.europa.eu
[6] www.entsog.eu
[7] www.entsoe.ee
[8] www.eia.gov/countries, www.cia.gov/library/publications/the-world-factbook

reference prices are taken from [24]. As discussed, particularly for production costs and supply behavior no consistent or complete data is available. The same lack of data holds true for transport costs. Rather than making a necessarily arbitrary bottom up assessment, we opted for a transparent and simple approach: Transport costs and losses are fuel dependent, are for the most part distance-based, and, in terms of natural gas pipelines, depend on whether the pipeline is onshore or offshore. Production capacities are determined by adding some slack to the reference output values based on market expertise, varying from 2% to 7%. For instance, a country like Germany will have minimal slack for oil and gas production, but countries like Norway and Russia will have more slack. This way we can study how supply from countries known to have some production flexibility may change as a result of case assumptions. Due to the steep cost increase of the Golombek function close to full capacity, it is not likely that a country will produce at full capacity. We have assumed the exertion of market power by some suppliers in the oil and gas market. The supply function parameters are calibrated to reflect actual production, consumption, and net trade volumes.

The main energy transformation processes incorporated are oil and biofuel refining and power generation. All these processes have per unit costs, capacities and transformation efficiencies that can vary by country. Crude oil refining data come from IEA. There is only one output fuel, and no distinction is made between the outputs. Biofuel refining capacities are based on the reference values by [24]. Power generation is incorporated by fuel input type, but no specific technologies are distinguished, and no fuel substitution is possible within a single unit. Hence, there is one type of natural gas fired power plant, one type of coal fired power plant, etc. Changes in fuel supply costs and GHG prices can induce shifts between different power plants, effectively allowing for fuel substitution in electric power generation.

Not having a differentiation between peak and base load in the data set will naturally lead to a merit order for power production based on (short-run) marginal cost. By using the power mix constraint (see Eq. 8) a minimum share of natural gas- and oil-based electrical generation is enforced in several countries. However, the model results still show somewhat higher than real world usage of coal and lower natural gas usage. In the model the use of oil for generating power is negligible.

In the short term, the substitutability options for most demand sectors are limited. Transportation can potentially absorb large shares of biofuels quickly. Industry has some switching options, however it is difficult to assess to what extend [31]. The short-term use of fuels by the residential and commercial sector is almost completely determined by the equipment stock and tends to not be very responsive to (short-term) price fluctuations. In summary, the demand sectors are: transportation, other fuel demand, coal, natural gas and electricity demand.

In the calibration, a CO_2 emission tax is assumed of \$20/ton in the EU27+Norway (the countries in the ETS) and no other taxes or emission ceilings are assumed.

BP [24] shows significant discrepancies between global production and consumption volumes for various fuels. IEA balances[9] provides part of the explanation: aside from the impact of statistical differences and unit of measurement standardization, stock changes can be quite large from one year to the next. Single-period models cannot capture such effects, and some deviation of reference values must be accepted. The model is calibrated to closely match production and consumption levels (See Table I). In the columns, from left to right: Electricity, Solids (Coal), (Crude) Oil, (Refined) fuels, (Natural) Gas, Nuclear power, and Renewables. Renewables are split into Hydro power, biofuels and all other (e.g., solar). The major differences are lower production in the model of solids (SOL) and higher production of crude oil (OIL) to allow the model outputs for consumption values to be closer to the reference values.

This concludes the description of the input data. Whenever relevant in the results discussion, more details are provided.

TABLE I
GLOBAL AGGREGATE CALIBRATION AND REFERENCE VALUES (MTOE)

Category	ELE	SOL	OIL	FUE	GAS	NUC	REN
Production		3633	3968		2889	626	972
Prod ref		*3731*	*3914*		*2881*	*626*	*974*
Refineries			-3863	3631			
Transf Loss				232			
Power Gen	1822	-826	-37		-374	-238	-347
Transf Loss		-1652	-68		-599	-388	-567
Gross Cons	1822	3633	105	3863	2844	626	972
Cons ref		*3556*		*4028ˆ*	*2858*	*626*	*915ˆ*
Transp loss	-1				-45		
Net Cons	1821	1155		3631	1871		57
Transport				2384			57
Fuels other				1247			
Coal		1155					
Gas					1871		
Power	1821						

Reference values are given in italics; all other are model results.
ˆBP [24] reports crude oil refinery losses and biofuels consumption as part of (refined) fuels consumption.

IV. CASE STUDIES

The cases presented here show the model's capabilities by analyzing actual recent developments. The ETS has been in place since 2005. It was implemented to curb CO_2 emissions by the participating countries by allowing a number of emission permits that can be traded at market based prices [32]. Instead of applying an emission ceiling, we investigated the consequences of implementing a carbon tax. In the first case, we vary the CO_2 emission tax from \$10 to \$100 per ton, in steps of \$10. Note that the (calibrated) reference value is \$20.

In the second case, we implement a global CO_2 emission tax. The global CO_2 emission tax is varied from \$0 to \$50 per ton, in steps of \$5. A third set of cases focuses on Germany, the largest economy in the EU27. Under pressure of public opinion, in the 1990s the German parliament discussed and decided to phase out nuclear power generation and push the large-scale use of electricity from renewable sources through

[9] www.iea.org/stats/prodresult.asp?PRODUCT=Balances

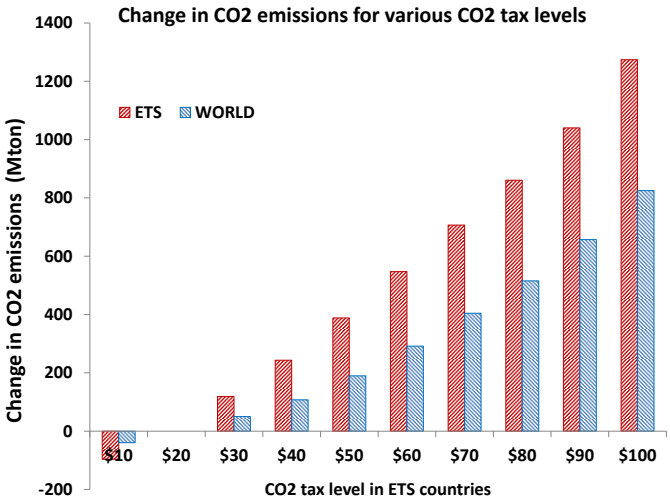

Fig. 2. Reductions (Mton) relative to reference CO_2 emissions

feed-in tariffs. This phasing out decision was partly reverted several years later; however, after the nuclear meltdown in the aftermath of the Japan earthquake and tsunami in March of 2011, a phase out was again announced. In 2010, Germany exported small amounts of electricity to neighboring countries. Phasing out nuclear plants will require alternative power generation sources. The options considered in the case studies are additional gas fired power generation fed by the first pipeline of the Nord Stream, a 50% increase in renewables, and the Green Battery option where Norway installs additional hydro or wind power capacity and a new power transmission line to Germany. For contrast, the consequences of all options are shown separately as well as combined. We realize that not all options can be made available over night, however we believe that the results do provide interesting insights into the dynamics of the energy markets.

European CO_2 tax

In the first case, we vary the CO_2 emission tax in the ETS region from \$10 to \$100 per ton, in steps of \$10. Note that the (calibrated) reference tax is \$20. The reference level of CO_2 emissions by the ETS region is 3,800 Mton; the global level is 30,600 Mton.

Figure 2 shows that at higher CO_2 tax levels in the ETS region, the marginal emission reduction for additional tax increases becomes larger, and that a smaller share of the ETS emission reduction will be emitted elsewhere. Each \$10 increase in ETS CO_2 tax induces an increasingly larger reduction of CO_2 emissions, both in the ETS region and globally. In the ETS region, increasing the tax level from \$10 to \$20 leads to a decrease of 97 Mton in CO_2 emissions (globally 40 Mton; 41% of 97), whereas increasing the tax from \$90 to \$100 induces a decrease of 234 Mton in the ETS region (168 globally, 72% of 234). At a tax level of \$100 in ETS the decrease in ETS emissions is 1274 Mton, 1/3 of the reference emissions. Globally emissions would be 825 Mton lower, 2.7% of global reference emissions.

The nonlinear increase in ETS CO_2 emissions can be explained as follows. In the reference case there is still relatively more slack in the various energy and electricity production and transportation options. In some countries the marginal costs of producing electricity from coal or natural gas does not differ extensively, and switching from coal to natural gas is still possible. Eventually, capacity of natural gas fired power plants and the natural gas production and transportation become restrictive. Consequently, supply prices may increase more sharply and consumption levels will drop.

In the ETS region, non-power coal use drops by about 50% at the maximum tax level, and coal-fired power production drops by 92%. Globally, coal consumption for non-power generation usage increases slightly and decreases for power production at all tax levels. Initially, lower coal use in the ETS region will push global coal prices downward, and other regions will use more coal. The additional use of coal in power generation is, however, limited by the coal-fired generation capacities. As a result, at higher tax levels, the CO_2 emission reductions in the ETS region are compensated less by additional emissions elsewhere; at higher tax levels the marginal effect on global reduction of CO2 emissions is larger. Electricity prices rise, but not enough to affect the use of oil in power generation. And although, at lower tax levels, the use of gas in power production decreases, at higher tax levels gas use increases once more. Hence, the share of gas in the fuel mix of electricity generation depends on the CO2 reduction ambitions.

Interestingly, imports of all fossil fuels by ETS countries decrease more than domestic production. At a tax level of \$100, the ETS regions even *exports* coal. This result is somewhat surprising, since CO_2 emissions from production are assigned to the producing country which would provide an incentive to increase imports. An explanation may be that transportation costs for coal are quite high relative to the production cost, and the cost benefit of not emitting CO_2 domestically does not outweigh the transportation costs.

A CO_2 tax affects the fuel mix in power generation as well as the trade in fossil fuels. The downward pressure on coal and other fossil fuel prices in regions not involved in the ETS increases fossil fuel usage in other regions. At higher tax levels, however, this compensation effect becomes smaller.

Global CO_2 tax

In this case, the global CO_2 emission tax is varied from \$0 to \$50 per ton, in steps of \$5. Figure 3 shows the CO_2 emissions at each tax level for all major world regions.

The marginal impact of a \$5 tax increase grows from 401 Mton in the first step to 526 Mton in the last step. A global tax of \$50 would lower CO_2 emissions by 15.5%. The regional shares in CO_2 emissions are almost constant; however, a closer look reveals some interesting details. Figure 4 shows the decrease in CO_2 emissions in the ETS region and North America as a percentage of the emissions when no CO_2 tax applies. At low tax levels, the relative reduction is higher in North America, but at higher tax levels, the reduction is higher in the ETS region.

This result can be explained as follows: In the reference case, the electricity production in North America is 45.2%

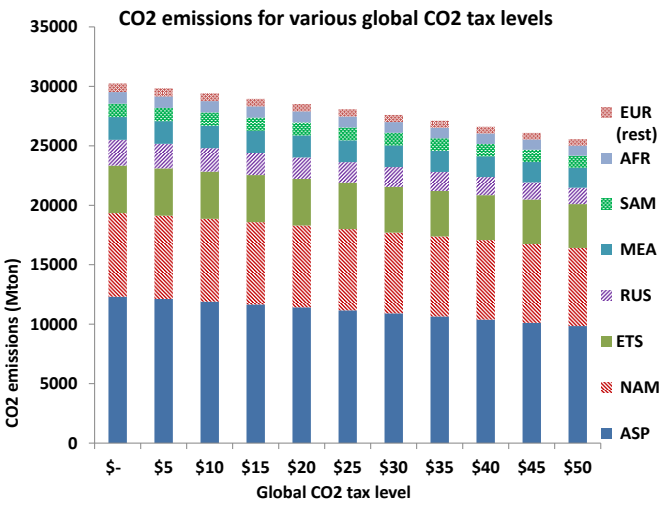

Fig. 3. CO_2 emissions in world regions for various CO_2 tax levels (Mton) ASP: Asia Pacific, NAM: North America, ETS: EU27+Norway, RUS: Russia incl. Caspian region, MEA: Middle East, SAM: South America, EUR(rest): European Countries not in ETS.

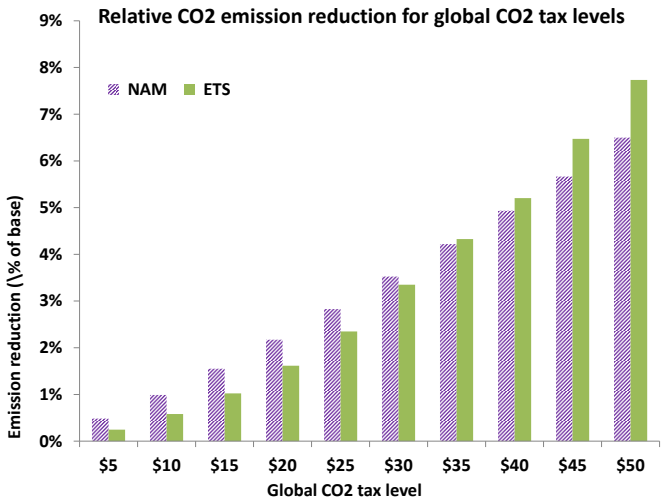

Fig. 4. Relative CO_2 emissions North America (NAM) and ETS

coal-based, and 20.5% gas-fired. There is minimal slack in power generation capacity. In contrast, in the ETS region, the coal fired power generation share is much lower, (only 31.1%), and the gas share is very similar to North America's gas share (21.4%). Additionally, in the ETS region, there is still slack power generation capacity in both coal and gas fired generation. Initially, at low tax levels, in the ETS region some coal fired power production can be substituted by gas fired production to meet end user demand. However, this gas must be imported through pipelines or as LNG and slack production and transportation capacity is limited. Hence, at some point supply prices will increase more harshly, affecting demand levels. In contrast, North America produces a larger share of coal and gas consumption domestically compared to ETS countries and suffers less from transportation bottlenecks, ultimately leading to lower reductions at higher tax rates.

The results obtained are partly steered by the calibration, for

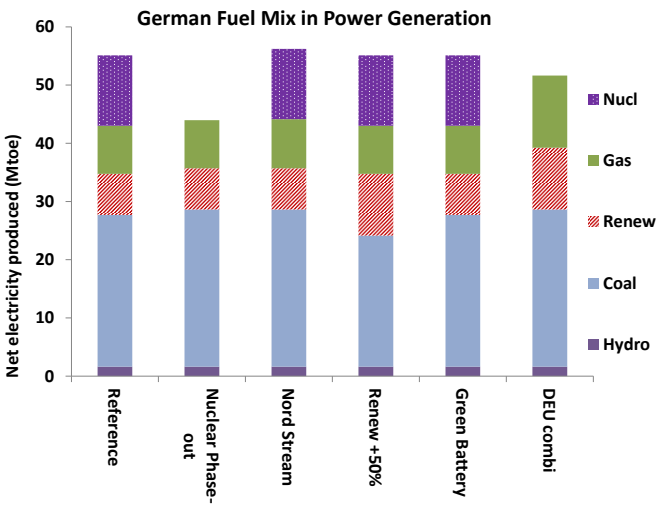

Fig. 5. FIGURE German Fuel Mix Power Generation (Mtoe after conversion)

instance, the choices for available power generation capacity. Nevertheless, the insights obtained are valuable. The results illustrate that the reductions obtained at various tax levels can differ by region, and that reduction values for small tax rates cannot simply be extrapolated to estimate the reductions for higher tax levels.

Focus on Germany

In the third case, we investigate the consequences of a nuclear phase out on German electricity production and consumption. Figure 5 shows the fuel mix in the German electricity production for all cases. In the reference case, the total power production amounts to 55 Mtoe, almost half of this is from coal (26 Mtoe). Of the total, 12.1 Mtoe comes from nuclear power, 8.3 comes from natural gas and 7.1 comes from renewables. There is 0.9 Mtoe slack in coal fired power production, and approximately 11 Mtoe in oil fired power production, all other options have no slack.

First, we discuss the consequences of separate measures and options. In case of a nuclear phase out, domestic electricity production decreases drastically. Prices rise, and coal fired power plants are used at full capacity; however oil fired capacity is still not used. The addition of Nord Stream and additional gas fired power generation capacity increases the gas fired electricity output by only 0.17 Mtoe (48% conversion efficiency about 0.35 Mtoe input based). Somewhat surprisingly, the coal fired capacity increases to full capacity. This is due to the fuel mix constraint, where because of peak load generation considerations gas and oil have a minimum share, and nuclear, coal, and the other options are competing for the rest. As a consequence both lower nuclear output and higher gas output allow for higher coal output. Additional renewables push out coal, with no other effects. Allowing Norway to export more electricity to Germany does not affect the fuel mix in Germany. However, it affects electricity trade. The results of the combination case show a mix of the outcomes obtained in the other cases, with one note: the output of gas fired power generation increases by 4.1 Mtoe (about 8.5 Mtoe

before conversion). Electricity consumption is highest in the Nord Stream case: 54.5 Mtoe, 9% higher than the 50.0 in the phase out case with the lowest electricity consumption.

Analysing electricity trade results supports the analysis provided above. Because of limited space, we did not include a figure for the electricity trade. In the reference case, Germany exports 0.8 Mtoe of electricity. In the nuclear phase out case, Germany imports 6.0 Mtoe. Hence, of the 12.1 Mtoe of lost nuclear supply, trade compensates for almost 7, and as demonstrated above, another 0.9 is compensated for by additional coal fired generation. Additional gas supplies from Nord Stream lead to an increase in electricity exports of 0.9 Mtoe, and domestic electricity consumption increases by a mere 0.2 Mtoe. Additional electricity supply from Norway leads to a small increase in consumption (+0.2) and a small reduction of exports (+0.2). Finally, in the combination case, all mentioned options contribute to compensating the phased out nuclear supply including a net trade change of 1 Mtoe. (0.6 exports vs. 0.4 imports).

V. Conclusions

The results illustrate the capabilities of this multi-fuel market equilibrium model, wherein fuel substitution is addressed explicitly rather than implicitly through data assumptions or cross-price elasticities. In future work, we intend to address extensions such as more detail in power generation, network expansions in a multi-period setting, more detail for non-European regions, demand seasonality, load curves in electricity and stochasticity.

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