Consequences of the UK Energy Market Reform on the Development of Carbon Capture, Transport, and Storage

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Abstract—To achieve the three main energy policy priorities of competitiveness, energy security and decarbonization, the UK government has recently undertaken a major “Energy Market Reform” (EMR). This paper presents a modeling framework to analyze how the different policy measures of the EMR will shape the future UK electricity generation mix until 2050. We set up a two-sector model where players can invest in various types of generation technologies including renewables, nuclear, and Carbon Capture, Transport, and Storage (CCTS). For a detailed representation of CCTS we also include industry players (iron/steel as well as cement), CO₂ transport, and CO₂ storage including the option for CO₂-enhanced oil recovery (CO₂-EOR). The players maximize their expected profits based on variable, fix and investment costs, as well as the price of electricity, CO₂ abatement, and other incentives, subject to technical and environmental constraints. Demand is inelastic and represented via a selection of representative hours. The model framework allows for regional disaggregation and features simplified electricity and CO₂ pipeline networks. The model uses a mass balance as market clearing for electricity and CO₂. The equilibrium solution is subject to constraints on CO₂ emissions. In this paper we present the model formulation and some preliminary results to illustrate the mechanics of the model. The tentative scenario indicates a diversified technology mix for 2050. The CCTS development is purely triggered by CO₂-EOR; the EMR does not incentives any additional CCTS investments.

Index Terms— CCS, CO₂, electricity, energy policy, MCP, UK

I. INTRODUCTION AND LITERATURE OVERVIEW

The UK government decided to undertake a major restructuring of its energy policy framework, called the “Energy Market Reform” (EMR) [1]. The UK-EMR introduces four main policies to support low-carbon technologies: Contracts for Differences (CfD), Carbon Price Floor (CPF), Emissions Performance Standard (EPS) and a Capacity Market (CM). These instruments constitute a major reform to the previous framework of the UK electricity market, which was characterized by a high competitiveness and low market concentration.

The upcoming EMR and its effects have been controversially discussed, e.g. by Pollitt and Haney [2] and Eide et al. [3]. Some critics question the effect the reform might have on the UK electricity market and in particular on the future of low-carbon technologies. Major risks include possible welfare losses as well as possibly breached climate targets due to sunk investments in carbon-intensive power plants (a topic examined by Johnson et al.[4] on a global level). This calls for additional research on low-carbon technologies in the UK. One technology that is particular to the UK’s approach is Carbon Capture, Transport, and Storage (CCTS), which has vanished as technology option in most European countries [5]. Existing studies such as Egerer, Kunz and Hirschhausen [6] have concentrated their research on the integration of renewables into the UK electricity market. Their representation of the CCTS technology, however, neglects transportation and storage aspects as well as the possibility of industrial usage of CCTS. Other studies concentrate only on the technical or political feasibility of CCTS (see [7], [8]) or on possible pipeline routing (see [9], [10]), neglecting the integration of CCTS into the rest of the electricity market.

To our best knowledge, there is no study that examines the UK-EMR with respect to its implications for the CCTS technology and the UK electricity market. Therefore, the aim of this paper is to set up a modeling framework to analyze the measures of the UK-EMR (specifically the CPF, EPS and CfD) and how they will influence the construction of new generation capacities. The developed Electricity-CO₂ (ELCO) model calculates regionally disaggregated electricity generation and flows as well as CO₂ transport, storage, and usage for CO₂-enhanced oil recovery (CO₂-EOR) in UK until 2050. Incorporating CO₂ capture by industrial facilities from the iron/steel and cement sectors is another unique feature of this modeling approach. On the one hand, this facilitates the representation of economies of scale along the transport routes while, on the other hand, leading to a higher scarcity of storage options.

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II. MATHEMATICAL REPRESENTATION OF THE ELCO MODEL

The ELCO model includes stylized players of the electricity sector, iron/steel and cement industry, as well as CO2 transportation and storage. All players maximize their respective profits subject to their own as well as overall technical and environmental constraints. Other (external) costs as well as further welfare components are not being analyzed. CfD for low-carbon technologies are set exogenously for 2015 and 2020, and derived endogenously from shadow variables of environmental constraints for later periods. The EPS and the CPF remain exogenous throughout the modeling period. The equilibrium model assumes perfect competition as well as perfect foresight and is solved as mixed complementarity problem (MCP) with the General Algebraic Modeling System (GAMS) software using the PATH Solver. An equilibrium is reached when overall system costs are minimized subject to all constraints. The following notation uses capital letters for parameters and lower case letters for variables and sets.

A. The electricity sector

The ELCO model represents electricity generation from various technologies (g,n,t,a) (g-type): from existing capacities, newly built coal, gas, OCGT and gas CCST; and g_cfd (g-cfd-type): from PV, wind on/offshore, hydropower, biomass, CCTS coal/gas, and nuclear). Their objective functions (1) represent the profit functions for different technologies and share the common components of fix costs FC_G, a and annulized investment costs INVC_G, which both depend on the investments inv_G (lowest rectangular segment). The variable costs components and revenue differ: I) For g-type technologies (upper rectangle with upper flat corners), revenue is generated from sales in the electricity market. It consists of the dual variable of the electricity balance (19) price, a factor describing the technology’s contribution to achieving the environmental target (see (8)). The variable cost function comprises of fuel and O&M costs with a linear and a quadratic term (VC_G and INTC_G, respectively). CO2 costs based on the emission factor Ef, and the CO2 certificate price (CO2_PRICE (CPS),). II) For g_cfd-type technologies (middle rectangle with rounded corners), revenue is generated from the new CfD scheme. The strike price for a technology depends on the extent to which its generation helps achieving the environmental goals (see (8)). These technologies also incur additional variable costs from possible CO2 transport and storage, which are passed via the dual variable price_cfd, an account for CO2 capture rates CR. The quadratic cost term can be interpreted as rising integration costs for increasing shares of g_cfd-type generation.

The individual players maximize their profits subject to several constraints. The EPS constraint (2) ensures that newly constructed generation capacities do not exceed the annual allowed CO2 emissions per GW. The overall emissions are calculated as an annual fuel-specific sum, allowing for combined accounting of new capacities with and without CCTS. The model includes the option for curtailment of excessive (renewable) generation via (3).
Another constraint limits total investments depending on a technology-specific maximal potential (7).

$$0 \leq \text{MAX}_{n,i} - \sum_{a \in \text{SES}_{n,i}} \text{inv}_{a} \cdot g_{n,i,a} \downarrow \lambda_{n,i,a}^\text{pot,cr} \geq 0 \quad (7)$$

### Shared environmental constraints for the electricity sector

All players in the electricity sector have to respect shared environmental constraints; a CO₂ target guarantees that the annual dispatch is in line with an exogenously set CO₂ reduction path for the UK (8). Here, δₜₐₜ is the difference between the CO₂ intensity of the generation mix induced by an annual CO₂ target and the emission factor of a particular technology which can be both positive or negative.

$$0 \leq \sum_{a \in \text{SES}_{n,i}} TD_{a} \cdot \alpha_{a} \left( \sum_{a \in \text{SES}_{n,i}} g_{c} \cdot df_{a}^{n,i,a} + g_{h,n,i,a} \right) \downarrow \lambda_{a}^\text{pot,co2} \geq 0 \quad (8)$$

Many countries have additional renewables targets that could be incorporated via a similar renewables constraint. Such a constraint, however, is not analyzed in this paper.

### B. The industry sectors

Two industry sectors are represented: iron/steel as well as cement. The objective function of these sectors is limited to the abatement costs linked to exogenous CO₂ emissions. It includes the options of either paying the CO₂_PRICE_EUₐ or investing into the CCS technology with its variable costs VC_CO₂ₙₐₐ and annualized investment costs INVC_CO₂ₙₐₐ. The additional costs of the potential transport and storage of CO₂ are passed on from the CO₂ sector via the dual variable price_co₂ₙₐₐ.

The industry sectors maximize their objective function (9) subject to constraints similar to those of the electricity sector.

$$\Pi_{\text{IND}} = \sum_{a} DF_{a} \cdot PD_{a} \cdot$$

$$\left( TD_{h} \cdot (CO₂\_\text{IND}_{h,n,i,a} - \text{co2}_{h,n,i,a}) \right) \left( -\sum_{h} (\text{CO₂\_\text{PRICE}_a} + \text{co2}_{h,n,i,a} \cdot \text{price}_a + \text{VC\_CO₂}_{h,n,i,a}) \right)$$

$$-\left( \text{INVC\_CO₂}_{n,i,a} \cdot \sum_{a \in \text{SES}_{n,i}} \text{inv}_{a} \cdot \text{co2}_{n,i,a} \right)$$

A diffusion constraint (10) restricts the maximal annual investment depending on previous investments.

$$0 \leq \left( \text{START}_{\text{CO₂}} + \sum_{n \in \text{a}} \sum_{a \in \text{SES}_{n,i}} \text{inv}_{a} \cdot \text{co2}_{n,i,a} \right)$$

$$\cdot \text{DIFF}_{\text{CO₂}} - \sum_{n \in \text{a}} \sum_{a \in \text{SES}_{n,i}} \text{inv}_{a} \cdot \text{co2}_{n,i,a} \downarrow \lambda_{n,i,a}^\text{diff,co2} \geq 0 \quad (10)$$

The annual capturing quantity is restricted by the amount of previous investments (11) as well as the total emissions per node and technology (12).

$$0 \leq \sum_{a \in \text{SES}_{n,i}} \text{inv}_{a} \cdot \text{co2}_{n,i,a} \cdot \text{CR}_{\text{IND}}$$

$$-\text{co2}_{h,n,i,a} \downarrow \lambda_{h,n,i,a}^\text{cap,co2} \geq 0 \quad (11)$$

$$0 \leq \text{CO₂\_\text{IND}_{h,n,i,a}} \cdot \text{CR\_\text{IND}_{h,n,i,a}}$$

$$-\text{co2}_{h,n,i,a} \downarrow \lambda_{h,n,i,a}^\text{max,ind} \geq 0 \quad (12)$$

### C. The storage sector

$$\Pi_{\text{STOR}} = \sum_{a} DF_{a} \cdot PD_{a} \cdot$$

$$\left( \sum_{n \in \text{a}} TD_{h} \cdot \text{co2}_{s,n,a} \cdot (\text{EFF\_CO₂\_OILPRICE}_a + \text{price}_a \cdot \text{VC\_CO₂}_{n,a} + \text{INVC\_CO₂}_{n,a}) \right)$$

$$-\left( \text{INVC\_CO₂}_{n,a} \cdot \sum_{a \in \text{SES}_{n,a}} \text{inv}_{a} \cdot \text{co2}_{s,n,a} \right)$$

Offshore saline aquifers, depleted oil and gas fields (DOGF), and fields with the opportunity for CO₂-EOR are identified as possible storage locations. Onshore storage is not included in the examination due to limited geological potential and rising public resistance. The objective function for the storage sectors (13) represents the costs linked to the underground storage of CO₂. For CO₂-EOR sites it includes returns from oil sales at OILPRICEₐ. The storage costs consist of variable costs VC_CO₂₉ₕₕₕₕₕₕ, the quadratic cost term INTC_CO₂, and annualized investment costs INVC_CO₂₉ₕₕₕₕₕₕₕ. The dual variable price_co₂₉ₕₕₕₕₕ is used to pass on the overall storage costs (or in case of CO₂-EOR also possible returns) to the CO₂ transport sector.

The storage entities maximize their objective function subject to a respective diffusion constraint (14), which limits their maximal annual investment:

$$0 \leq \left( \text{START}_{\text{CO₂}} + \sum_{n \in \text{a}} \sum_{a \in \text{SES}_{n,i}} \text{inv}_{a} \cdot \text{co2}_{s,n,a} \right)$$

$$\cdot \text{DIFF}_{\text{CO₂}} - \sum_{n \in \text{a}} \sum_{a \in \text{SES}_{n,i}} \text{inv}_{a} \cdot \text{co2}_{s,n,a} \downarrow \lambda_{n,i,a}^\text{diff,co2} \geq 0 \quad (14)$$

Further constraints restrict the annual storage quantities, depending on previous investments (15) as well as the overall maximal storage quantity per node and technology (16).

$$0 \leq \sum_{a \in \text{SES}_{n,i}} \text{inv}_{a} \cdot \text{co2}_{s,n,i,a} - \text{co2}_{s,n,i,a} \downarrow \lambda_{n,i,a}^\text{max,inv} \geq 0 \quad (15)$$

$$0 \leq \text{MAX\_STOR}_{n,i} - \sum_{a \in \text{SES}_{n,i}} PD_{a} \cdot \sum_{a \in \text{SES}_{n,i}} (TD_{h} \cdot \text{co2}_{s,n,i,a}) \downarrow \lambda_{n,i,a}^\text{max,inv} \geq 0 \quad (16)$$

### D. The electricity TSO

The objective function of the electricity TSO is shown in (17). The CO₂ transportation sector is designed analogously to the electricity TSO and therefore not displayed in this paper. The sum of variable costs VC_F_Eₙₐₐ and annualized investment costs INVC_F_Eₙₐₐ equal the price difference between two nodes in case of no line congestion. Possible congestion rents are kept by the TSO as profit. Electricity is treated as a normal transport commodity ignoring Kirchhoff’s 2nd law, as network congestion is not the focus of the ELCO model.

$$0 \leq \text{DIFF}_{\text{CO₂}}$$
The CPF consists of the Carbon Price Support (CPS) which is 18 £/tCO₂ (around 25 €) in 2015 and the ETS price. We assume a continuous increase of the CO₂ price due to the effects of the structural reform of the ETS. The CPS, however, probably drops, resulting in a constant CPF of 35 £/t CO₂ until 2030. From 2030 onwards the CPF rises linearly to 70€ in 2050. All technologies under the CfD receive the proposed strike prices for 2015 and 2020 [16]. From 2025 onwards, an endogenous auctioning system will set an equal financial support for all CfD technologies. The EPS remains at its current level of 450€/kWh throughout the modeling process. The annual CO₂ target induces a reduction of CO₂ emissions in the electricity sector leading to a 90% decrease in 2050 compared to 1990. The discount rate is 5% for all players. The oil price is expected to remain at its current level of 65 €/bbl.

The annual UK load duration curve is approximated by five weighted representative hours, assuming a demand reduction of 20% until 2050 (base year 2015). This simplification does not allow for demand shifting nor energy storage in between periods. CO₂ emissions of the cement as well as iron/steel industry are assumed to be reduced by 40% until 2050. The lifetime of generation units varies by technology between 25 (most renewables), 40 (gas), and 50 (coal, nuclear, hydro) years; construction periods vary between 0 (PV) and up to 10 (CCTS, nuclear) years.

The simplified network used for this paper consists of three nodes (c.f. Fig. 1). Nodes 1 and 2 represent the Southern and Northern part of the UK, with their respective power plants and industrial facilities. The third node resembles possible locations for offshore wind parks as well as CO₂ pipeline facilities both with and without CO₂-EOR. We assume electricity and CO₂ pipeline connections to be between nodes 1 and 2, as well as between node 2 and node 3. This simplified case was created to show the characteristics and features of the ELCO model. Its results should not be over-interpreted; they should rather give an idea of the potential of the model once its complete data set is calibrated.

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E. Market clearing conditions across all sectors

Two market clearings connect the different nodes and sectors in the ELCO model: The first is the energy balance (19) with its dual variable price_\(e_{h,n,a}\).

\[
0 = \sum_{i} \left( g_{h,n,a} + \sum_{m \in \mathcal{M}_{h,n,i}} g_{m,h,n,a} \right) \\
+ \sum_{m} f_{m,h,n,a} - f_{h,n,a} - \sum_{m} e_{h,n,m,a} \\
- \left( D_{h,n,a} - \text{RES}_\text{OLD}_{h,n,a} \right) \cdot \text{price}_e e_{h,n,a} \quad \forall h,n,a
\]

The second market clearing is the CO₂ mass balance (20) with its dual variable price_\(co2_{h,n,a}\).

\[
0 = \sum_{i} \text{co2}_i e_{h,n,i,a} + \sum_{j} \text{co2}_j s_{h,n,i,a} - \sum_{j} \text{co2}_j c_{h,n,i,a} \\
- \sum_{m \in \mathcal{M}_{h,n,i}} g_{m,h,n,i,a} \cdot \text{EF}_i \cdot \text{CR}_i G_i \\
- \sum_{m} \text{co2}_i l_{m,n,a} \cdot \text{price}_\text{co2} e_{h,n,a} \quad \forall h,n,a
\]

III. DATA

Electricity generation capacities as well as data for investment cost, variable cost, fixed cost, availability, and lifetime assumptions are taken from DECC ([111], [112]). For investment costs, we assume cost reduction over time according to Schröder et al. [13]; variable and fixed costs remain constant. The costs are independent from power plant location, but the availability of renewables does vary. Industrial CO₂ emissions and their locations are taken from various studies concentrating on CCTS adoption in the UK industry sector ([14], [15]). Capturing costs in the industry sector as well as costs for CO₂ storage and CO₂-EOR application are taken from Mendelevitch [10]. Fix costs are included in the variable storage costs. We assume a simplified electricity grid, neglecting congestion in between nodes. In addition, no exchange with the neighboring countries is allowed. CO₂ pipelines can be constructed endogenously between the nodes.

IV. SCENARIO RESULTS

The scenario network used for this paper consists of three nodes (c.f. Fig. 1). Nodes 1 and 2 represent the Southern and Northern part of the UK, with their respective power plants and industrial facilities. The third node resembles possible locations for offshore wind parks as well as CO₂ storage facilities both with and without CO₂-EOR. We assume electricity and CO₂ pipeline connections to be between nodes 1 and 2, as well as between node 2 and node 3. This simplified case was created to show the characteristics and features of the ELCO model. Its results should not be over-interpreted; they should rather give an idea of the potential of the model once its complete data set is calibrated.
This scenario run indicates a diversified electricity portfolio in 2050: renewables (47%), gas (25%), nuclear (14%), and CCTS with CO₂-EOR (14%). As shown in Fig. 2, investment activity has two peaks: one early (2015) and diversified which is due to exogenous the strike prices; and one later (around 2040) with renewables and gas. Less favorable regional potentials and technologies such as PV are increasingly used in later periods. The implemented incentive mechanism is comparable to an auctioning system where the last bidder sets the price. The resulting endogenous payments for low-carbon technologies are in the range of 90 €/MWh, but depend strongly on the assumptions for learning curves and technology potentials.

Fig. 2 and Fig. 3 show the dispatch and the CO₂ stream for 2015, 2030, and 2050. The share of coal-fired energy production is sharply reduced from 46% in 2015 to 0% in 2030 due to a phasing-out of the existing capacities. Investment in conventional fossil-fueled capacities only occurs for OCGT and CCGT, which are built from 2030 onwards. EPS hinders the construction of any new coal-fired power plants. Sensitivity analysis shows that a change of its current level of 450 g/kWh in the range of 400-500 g/kWh has little effect, since gas-fired power plants would still be allowed sufficient run-time hours while coal-fired plants would remain tightly constrained. The share of renewables in the system grows continuously from 22% in 2015 to 47% in 2050. Wind off- (38% in 2050) and onshore (26% in 2050) are the main renewable sources.

![Figure 2. Dispatch by technology type and representative hour for 2015, 2030, and 2050 (top); and annual investments by technology type (bottom).](image)

![Figure 3. CO₂ capture and storage by type of orgin and sink.](image)
CO₂-EOR creates returns for CCTS through additional oil production. These profits trigger investments in CCTS power plants regardless of additional incentives from the energy market. The maximum share of CCTS in the energy mix is 14% in 2050. The combination of assumed ETS and oil price also triggers CCTS deployment in the industry sector from 2020 onwards. The industrial CO₂ capture rate, contrary to the electricity sector, is constant over all representative hours (c.f. Fig. 3). The storage process requires a constant injection pressure. This shows the need for intermediate CO₂-storage to enable a continuous storage procedure and should be more closely examined in further studies. 90% of the annual emissions from iron/steel and cement industries are captured from 2030 onwards. There is no investment in CCTS without the option of CO₂-EOR as cheaper low carbon technologies are available.

V. CONCLUSION

The results described in section IV present a showcase of our model framework. It incorporates the unique combination of a fully represented CCTS infrastructure (Carbon Capture, Transport, and Storage) and a detailed representation of the electricity sector in UK. The instruments of the UK Energy Market Reform (EMR), like Emissions Performance Standard (EPS), Contracts for Differences (CfD), and Carbon Price Floor (CPF) are integrated into the framework. We also take into account demand variation in representative hours, the availability of favorable locations for renewables, the limits of their annual diffusion, and an annual CO₂-target. This paper is used to describe the different features and potentials of the ELCO model, though its quantitative results should not be over-interpreted. For further development, we need to test the robustness of the equilibrium results with sensitivity analysis while increasing the regional and time resolutions of the model. The tentative scenario suggests that the EMR does not provide additional incentives for CCTS outside CO₂ use for CO₂-EOR.

The next steps are to compare the costs of different incentive schemes and to analyze their effects on the deployment of different low-carbon technologies with a special focus on CCTS, with and without the option for CO₂-EOR. The role of industry CCTS needs to be further considered in this context. In addition to studying the feedback effects between the CfD scheme and the electricity price, we plan to investigate the incentives of the government, which acts along the three pillars of energy policy: cost-efficiency, sustainability, and security. We want to use our results to draw conclusions and possible policy recommendations for low-carbon support schemes in other countries.

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