

Comparing post-combustion CO₂ capture operation at retrofitted coal-fired power plants in the Texas and Great Britain electric grids

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Received 22 December 2010

Accepted for publication 28 March 2011

Published 7 April 2011

Online at stacks.iop.org/ERL/6/024001

Abstract

This work analyses the carbon dioxide (CO₂) capture system operation within the Electric Reliability Council of Texas (ERCOT) and Great Britain (GB) electric grids using a previously developed first-order hourly electricity dispatch and pricing model. The grids are compared in their 2006 configuration with the addition of coal-based CO₂ capture retrofits and emissions penalties from 0 to 100 US dollars per metric ton of CO₂ (USD/tCO₂). CO₂ capture flexibility is investigated by comparing inflexible CO₂ capture systems to flexible ones that can choose between full- and zero-load CO₂ capture depending on which operating mode has lower costs or higher profits. Comparing these two grids is interesting because they have similar installed capacity and peak demand, and both are isolated electricity systems with competitive wholesale electricity markets. However, differences in capacity mix, demand patterns, and fuel markets produce diverging behaviours of CO₂ capture at coal-fired power plants. Coal-fired facilities are primarily base load in ERCOT for a large range of CO₂ prices but are comparably later in the dispatch order in GB and consequently often supply intermediate load. As a result, the ability to capture CO₂ is more important for ensuring dispatch of coal-fired facilities in GB than in ERCOT when CO₂ prices are high. In GB, higher overall coal prices mean that CO₂ prices must be slightly higher than in ERCOT before the emissions savings of CO₂ capture offset capture energy costs. However, once CO₂ capture is economical, operating CO₂ capture on half the coal fleet in each grid achieves greater emissions reductions in GB because the total coal-based capacity is 6 GW greater than in ERCOT. The market characteristics studied suggest greater opportunity for flexible CO₂ capture to improve operating profits in ERCOT, but profit improvements can be offset by a flexibility cost penalty.

Keywords: carbon dioxide capture, CO₂, carbon capture and sequestration, electricity, coal

1. Introduction

Carbon capture and storage (CCS) has been proposed as an option to mitigate the risk of climate change caused by

anthropogenic carbon dioxide (CO₂) emissions. While a drastic reduction in fossil fuel use for electricity generation might be desirable in the long term, CCS enables fossil fuels to be used for power plants in a more environmentally acceptable

manner in the short term. In a typical CCS project, CO₂ is captured and compressed at a large point source and is then transported by pipeline to a geological formation for permanent storage. A special report by the Intergovernmental Panel on Climate Change introduces many key CCS technologies [1].

There is a relatively large literature on design options for steady-state CO₂ capture operation at power plants with maximum fuel input, including studies commissioned by the International Energy Agency Greenhouse Gas R&D Programme (IEAGHG) that are summarized by Davison [2]. There has, however, been limited consideration of CO₂ capture across a range of operating modes that might be available to power plant operators seeking the most profitable strategy of CO₂ capture operation. Comparatively mature CO₂ capture and compression technologies are currently expected to reduce net electrical output by 20–30% (7–11% efficiency points) [3, 4]. A flexible CO₂ capture system that enables temporary recovery of some or all of this output could, therefore, be valuable during peak electricity demand and price conditions or during grid reliability disruptions [2–6]. The conditions that justify flexible or inflexible CO₂ capture operation will also vary for different electricity markets, so direct comparison of electricity systems is essential to fully understanding the implications of CO₂ capture. With several commercial-scale power plant CO₂ capture projects currently under development, a more sophisticated understanding of dynamic CO₂ capture operation is becoming increasingly important [5].

This work uses a first-order electricity dispatch model to compare the implications of flexible and inflexible CO₂ capture on the Electric Reliability Council of Texas (ERCOT) and Great Britain (GB) electric grids. It aims to provide an assessment of the relative environmental and economic impacts of CO₂ capture in each grid for an illustrative concept for flexible operation. Previous work has used the same model to explore the implications of flexible CO₂ capture in ERCOT [4–6], and the current study validates its applicability to other electricity systems using the example of the GB electric grid. This paper illustrates the methodology for adapting the model to another electricity system and presents results comparing the ERCOT and GB systems under various market CO₂ prices. These grids comprise an interesting comparative test case for reasons discussed in section 2.

The two grids are compared using electricity demand and plant installations in 2006 to match data availability and produce output consistent with earlier work [6–8]. Neither grid had CCS facilities installed in 2006, so they are compared with CO₂ capture by assuming that approximately half of the installed coal-based capacity is retrofitted with CO₂ capture. The ERCOT and GB grids are compared for exogenous CO₂ prices of 0–100 US dollars per metric ton of CO₂ (USD/tCO₂), and all monetary quantities assume 2006 USD. CO₂ capture retrofits for natural gas-fired facilities might also be economical at high CO₂ prices, but this study focuses only on CO₂ capture for coal-fired plants.

Historical grid conditions are used instead of projected configurations because this work is intended to compare CO₂ capture operation within two contrasting electricity systems,

not to provide illustrative scenario analysis. Market forces and policy developments might lead to a significant decrease in coal-based generation and increasing prevalence of natural gas and renewables in both grids. Natural gas and renewables are receiving substantial attention in the UK, and at the time of writing (late 2010) ERCOT has already installed over 9 GW of wind generation capacity [9]. The modelling framework used in this analysis can be adapted to analyse such scenarios, but this paper restricts its scope to 2006 configurations with coal-based CO₂ capture and a range of CO₂ prices.

2. Motivation for comparing the ERCOT and GB grids

The ERCOT and GB grids have similar total generation capacity, total demand, and peak demand (figure 1), and both systems use a deregulated market for wholesale electricity sales. Aside from a small quantity of GB electricity traded across interconnectors to France and Ireland, both electric grids are essentially self-contained ‘island’ electricity systems [10]. Texas is not geographically separated from other US electric grids, but ERCOT functions as its own interconnect entirely within Texas. Only a small amount of electricity flows from ERCOT territory to other US interconnects and Mexico through DC power lines [11].

Figure 1 shows the per cent capacity of each power plant type in the ERCOT and GB grids in 2006 along with per cent generation by plant type for ERCOT and the United Kingdom (UK). ERCOT has a much greater percentage of gas-fired capacity, while the UK has a larger capacity contribution from coal- and nuclear-based power. Both grids also utilize significant quantities of natural gas-based combined heat and power (CHP) units for commercial and industrial activities. CHP plants are usually designed to supply heat load rather than electricity, so they typically operate at maximum electrical output if heat demands are relatively constant. Neither grid had a large quantity of renewable capacity in 2006, though ERCOT now contains over 9 gigawatts (GW) of rated wind capacity, and both grids expect significant future renewable growth [9].

Overall generation by plant type is more similar than capacity distribution. Annual generation is 16% greater in the UK than ERCOT, but per capita energy consumption is 2.7 times higher in ERCOT, which has one-third the population of the UK. While natural gas-based plants make up a much greater fraction of total capacity in ERCOT, their relative contribution to generation is far less than capacity because nearly half of ERCOT’s gas-fired facilities are infrequently-used gas-fired boilers [12]. In ERCOT, coal has remained much cheaper than natural gas, and there is no price on CO₂ emissions, so coal-fired plants typically provide base load generation [13, 14]. In the GB grid, higher average coal prices, CO₂ prices imposed by the EU emissions trading scheme, and seasonal natural gas price variations typically lead to a seasonal switch in which fossil-fired power plants provide base load power generation. Coal-fired generators typically provide GB base load in the winter when heating demand raises natural gas prices, but natural gas combined cycle (NGCC) plants tend to displace coal-fired facilities in the summer when natural gas prices fall [15]. A number of factors influence fuel price differences

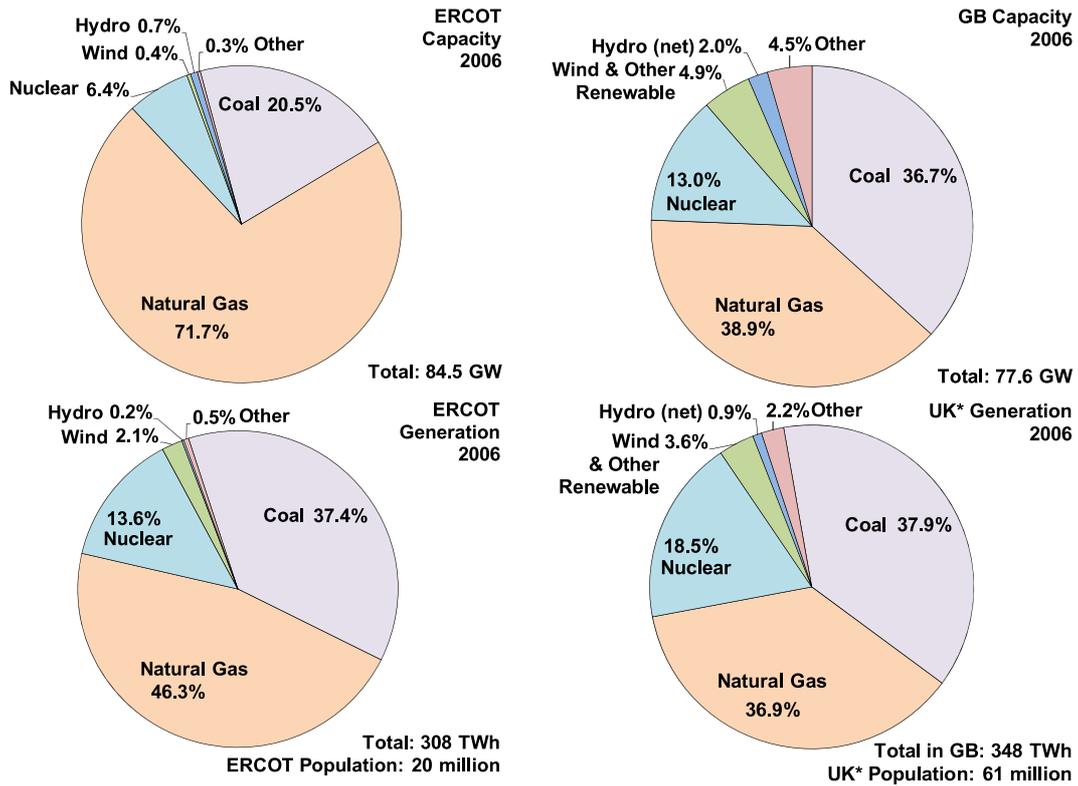


Figure 1. Despite ERCOT’s large natural gas-fired fleet, energy produced by plant type was relatively similar for ERCOT and GB in 2006. *UK generation percentages and population include N. Ireland and Scottish Isles, which are not included in the GB grid (GB grid contains around 91% of UK capacity) [9–12, 16, 17].

between the two systems. Coal prices are generally higher in the UK due to the influence of high grade, high price coal that is internationally traded. By contrast, coal supplies for ERCOT are domestic and mostly isolated from international prices. CO₂ prices also reduce dispatch of coal-based generators in the UK because they emit approximately twice as much CO₂ per megawatt hour (MWh) as typical NGCC facilities.

Figure 2 plots the frequency distribution of ERCOT and GB 2006 hourly electricity demand in bins with 1 GW range. Though ERCOT peak demand is higher, higher demand is more common in GB, so mean and total annual demand are greater [16, 17]. Because fuel and CO₂ prices in GB push coal-based plants later in the dispatch order than is typical in ERCOT, electricity demands where coal-fired facilities might set the marginal electricity price are much more common in GB. Similarities in size and market structure along with differences in power plant makeup, commodity markets, and electricity demand patterns make an ERCOT and GB grid comparison particularly interesting.

3. CO₂ capture with post-combustion amine absorption and stripping

CO₂ capture is potentially applicable to both new and existing fossil-fuelled power plants, but the present work only considers illustrative cases where CO₂ capture is retrofitted to existing ERCOT and GB coal-fired facilities. Such extensive

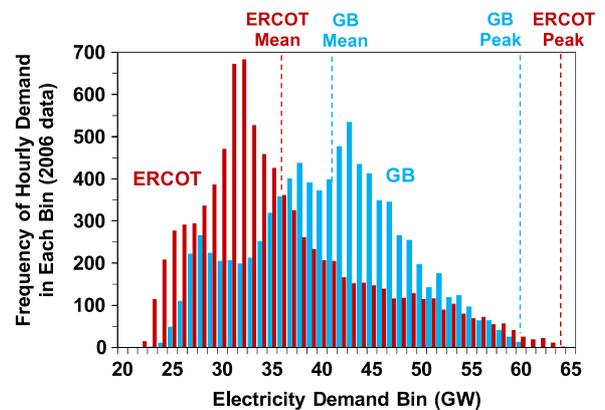


Figure 2. Through the course of a year, ERCOT (red) has higher peak electricity demand, but GB (blue) has higher average electricity demand.

retrofitting might not be possible. The focus of this approach is, however, to explore how a fleet might operate if this amount of retrofitting had occurred. The approach assumes that CO₂ price is the primary driver for using CCS once it has been installed, with coal-fired plants typically expected to have lower CO₂ avoidance costs than gas-fired facilities due to higher flue gas CO₂ concentration and lower flue gas flow rates [2]. Post-combustion amine absorption and stripping is the only CO₂ capture technology modelled because it is a promising,

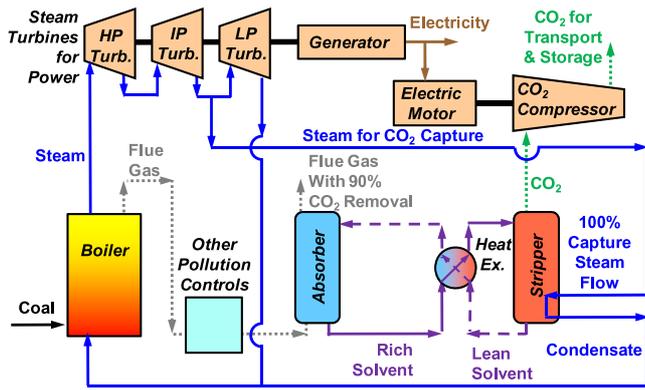


Figure 3. A simplified diagram of a typical inflexible post-combustion amine absorption and stripping system that removes around 90% of CO₂ from flue gas but reduces net electricity output by 20–30%.

retrofitable system that has been used commercially for CO₂ capture in natural gas and ammonia production facilities for several decades, albeit at much smaller scales than coal-fired power plants and with different inlet gas compositions [18].

Figure 3 illustrates a typical absorption/stripping system integrated with a coal-fired power plant. During full-load CO₂ capture, the entire flue gas stream produced by the base plant passes through the absorber and contacts a solvent that removes around 90% of the CO₂ [2]. The ‘rich’ solvent loaded with CO₂ then flows through a heat exchanger before CO₂ is stripped out by heating the solvent in the stripper column with steam extracted from the steam cycle. CO₂ is then dried and compressed before transport and storage, and the ‘lean’ solvent returns to the absorber. In a typical retrofit, 30–50% of the steam must be extracted from between the intermediate and low pressure (IP and LP) turbines for full-load CO₂ capture, and the CO₂ capture process reduces net electrical output by 20–30% (7–11% efficiency points) [3, 4, 19, 20].

Figure 4 demonstrates one flexible CO₂ capture concept that allows a plant retrofitted with CO₂ capture to regain most of its pre-capture output by returning CO₂ stripping steam to the LP turbine to produce electricity. CO₂ compression work then falls because there is less CO₂ to be compressed, though the minimum compressor flow rate may necessitate CO₂ recycling at low capture load. During partial-load CO₂ capture, one operating approach is for steam and rich solvent flow to the stripper to be reduced simultaneously and equally. Previous work has suggested that this is the best approach to minimize efficiency penalty and maintain system stability [6]. Rich solvent diverted from the stripper is recycled to the absorber, so CO₂ removal decreases and emissions increase as solvent becomes saturated with CO₂. Increased CO₂ emissions could incur additional CO₂ costs; however, partial-load CO₂ capture could be profitable if additional electricity sales offset increased CO₂ emissions costs [6, 20].

4. Modelling methodology

The custom first-order electricity system model described in this paper operates in a MATLAB programming environment

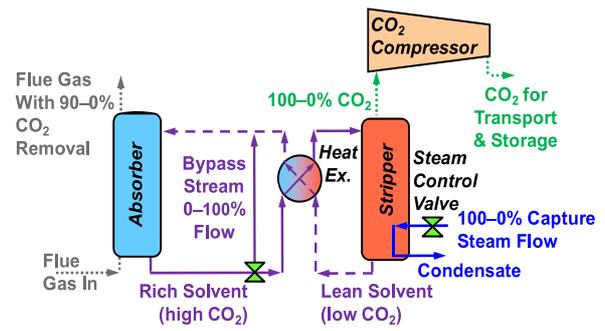


Figure 4. One flexible CO₂ capture concept simultaneously reduces steam and rich solvent flow to the stripper to enable increased output but at the expense of additional CO₂ emissions.

and compares electric grid scenarios with and without flexible and inflexible CO₂ capture. A detailed model description and input parameters for ERCOT are contained in several other reports and publications [6, 7, 21]. The model imports hourly electricity demand over one year and creates a least-cost dispatch order for each hour by calculating the marginal costs of electricity production for each facility in that hour. The model places all facilities in cost order in each hour and chooses facilities from least-to most-expensive until demand is met. It then approximates the pricing rule in a competitive electricity market by setting the electricity price equal to the marginal cost of the most expensive plant dispatched in that hour. Having calculated plant output, plant operating costs, and electricity prices in each hour, before-tax operating profits can be found. After completing this process for each hour in the year, aggregate annual electrical output, CO₂ emissions, and operating profits can be determined for each power plant or power plant type. Payments for providing grid reliability, or ancillary, services are not modelled.

Marginal generation costs at each facility are calculated in USD per MWh and include any applicable fuel, CO₂, and base plant variable operation and maintenance (O&M) costs as well as any additional costs associated with CO₂ capture. Fuel costs for fossil fuel-based facilities are the product of fuel price in USD per million British thermal units (USD/MMBTU) and heat rate (MMBTU/MWh) adjusted for CO₂ capture energy requirements when applicable. Co-firing of multiple fuels is ignored, so facilities are assumed to only use their predominant fuel. CO₂ emissions cost for fossil fuel-based plants is the product of CO₂ price (USD/tCO₂) and CO₂ emissions rate (tCO₂ MWh⁻¹) adjusted for any applicable CO₂ capture emissions reduction and energy requirement. Base plant O&M costs not attributed to fuel or CO₂ are specified directly, as are marginal generating costs of non-fossil fuelled-power plant types. Base plant heat rate, CO₂ emissions rate, and other performance parameters are approximated as constant over the operating range, so unless a facility is the price-setting plant in a given hour, the base plant is either off or at its maximum output.

Additional marginal costs for plants with CO₂ capture include costs associated with solvent makeup, reclaiming degraded solvent, disposing solvent degradation products,

additional water use, transport and storage, and additional maintenance, labour, and administration. Solvent makeup costs assume a solvent degradation rate per quantity of CO₂ removed. The CO₂ capture system is assumed to utilize thermal reclaiming to regenerate some degraded solvent using sodium hydroxide (NaOH), and the resulting waste disposal cost depends on degradation rate, NaOH input requirement, water fraction in the waste stream, and waste disposal costs per unit mass. Additional water use is estimated using results from a US National Energy Technology Lab (NETL) plant design analysis [19]. CO₂ transport and storage costs are specified directly as USD/tCO₂ captured. Average maintenance, labour, and administration costs are a function of CO₂ capture equipment capital costs, assumed wages and employees, and cost factors for maintenance, labour, and administrative support. A more detailed description of cost methodology is included in other work [21].

Maintenance schedules and other outages are ignored by the model to avoid having to make arbitrary or random decisions about which plants are offline in each hour. Instead, the effect of planned and unplanned outages on available generating capacity is assumed to average out over a year-long timescale, so the model accounts for the overall effect of outages by using each plant's annual average available capacity as its maximum capacity for each hour. Accounting for variations in available capacity over the year would improve model representation of diurnal and seasonal market dynamics, but the use of annual average available capacity is effective for achieving good agreement with annual aggregate historical data. The rule-based dispatch algorithm does not account for sophisticated plant-and grid-level constraints such as transmission congestion and ramp rates, but it successfully approximates a competitive electricity market to a first-order and provides useful insight into the role of flexible and inflexible CO₂ capture facilities in the electric grid [7]. The model is useful for comparing wholesale electricity prices across electricity market conditions, but it does not reproduce realistic electricity price volatility and price spikes. Therefore, while this model is effective at revealing important high-level trends and large-scale operating characteristics, the results do not apply for all situations where flexible CO₂ capture might be relevant.

The model can be used for any electricity system with requisite input data, but the ERCOT electric grid has previously been the primary case study due to access to expertise and data availability from the US Energy Information Administration (EIA), ERCOT, and the US Environmental Protection Agency (EPA) eGRID database [12, 16, 22]. In prior analyses, the model was built to consider coal-fired, NGCC, natural gas boiler, simple cycle gas turbine (NGGT), nuclear, and wind-powered facilities. All other capacity types were aggregated with the wind category and given properties of wind generation because they make up a very small fraction of the ERCOT capacity mix. For the present study, the model was updated to separately classify hydroelectric and miscellaneous peaking facilities comprised mostly of oil-fired facilities, both of which are more prevalent in the GB grid. In addition, the electricity dispatch algorithm was adjusted so that gas-fired

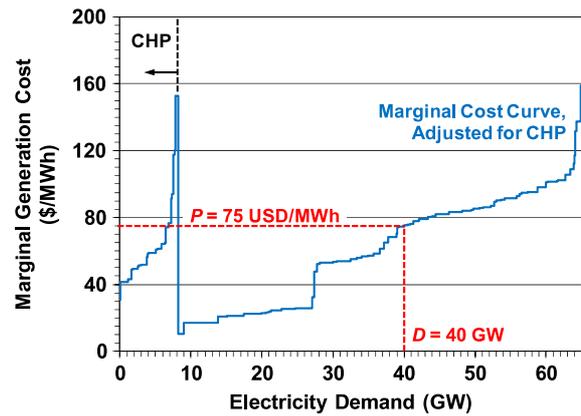


Figure 5. A sample aggregate grid-wide marginal cost curve illustrates how the first-order dispatch model finds a 75 USD MWh⁻¹ electricity price when demand is 40 GW. CHP facilities are always dispatched regardless of cost.

CHP facilities always produce electricity at their average available capacity regardless of their operating costs. This revision accommodates the logic described in section 2 that CHP plants are dispatched primarily for heat rather than electricity.

To graphically demonstrate the dispatch methodology, an example of an aggregate grid-wide marginal cost curve generated by the model is shown in figure 5, where CHP facilities are shown dispatched first. For this marginal cost curve, an electricity demand of 40 GW would yield an electricity price of about 75 USD MWh⁻¹. The dispatch model generates a marginal cost curve and finds an electricity price in this manner for each hour based on hourly plant and grid specifications.

For each set of input parameters, the model considers four scenarios used to compare an electric grid with and without flexible and inflexible CO₂ capture.

BAU (business as usual)—no CO₂ capture. The business as usual scenario does not include any CO₂ capture facilities.

CCS Base—inflexible CO₂ capture. For the base case CO₂ capture scenario, CO₂ capture systems must operate at 100% (full) load whenever the Base plant is operating.

FLEX Op Costs—flexible CO₂ capture option. In this flexible scenario, plants with CO₂ capture choose the operating condition (zero or full load) that has the lowest marginal cost of electricity production.

FLEX Profit—flexible CO₂ capture option. In every hour, each plant with CO₂ capture calculates its hourly profits for two scenarios: if all plants with CO₂ capture operate with the capture plant at (A) full load or (B) zero load. If profits are greater for a particular plant for option A, that plant will operate capture at 100% load; otherwise, it will operate at zero load.

5. Model input parameters

5.1. Electricity demand

Historical 2006 hourly electricity demand is publicly available for ERCOT and the GB system [16, 17]. The model is not designed to accommodate dispatch and operation of pumped storage hydroelectric facilities, so pumped storage facilities are not included in the set of GB power plants modelled, and the demand data exclude electricity used for pumping at pumped storage facilities. The difference between pumping energy and electricity supplied from pumped storage in the UK was 1.2 TWh in 2006 (0.3% of total demand), so excluding pumping energy and pumped storage facilities from this analysis should have a negligible effect on results [10].

5.2. Model validation procedure

The model was previously validated for the ERCOT grid by comparing calculated and historical annual electrical and CO₂ output for major plant types [7]. Satisfactory agreement was achieved using average annual fuel prices from the EIA. Power plant cost and performance parameters used in the present analyses were taken directly from sources used in previous work; the only exception was a slight adjustment to average available output at some facilities to improve agreement with historical data [21]. Success with ERCOT invokes confidence that the model's decision-making processes are effective for reproducing high-level electric grid behaviours when good quality data are available for all required input parameters.

In this work, ERCOT fuel prices and plant performance parameters are unchanged from prior analyses. However, because the model was modified to separately consider hydroelectric, gas-fired CHP, and miscellaneous peaking facilities, ERCOT plants of these types were recategorized from previously used generic categories to the more specific plant types. Most electricity from the miscellaneous peaking category is produced by oil-fired facilities, so all plants in the category were given characteristics of oil-based plants.

For the GB grid, individual power plant efficiency and CO₂ emissions rates are not publicly available, so the performance parameters required by the model were generated by adjusting performance data for US power plants based on aggregate performance reported in the Digest of UK Energy Statistics (DUKES) and known characteristics of the GB system [10]. Further complicating matters, seasonal variations in GB natural gas price and exposure of GB coal supplies to international markets created greater economic parity between coal- and gas-based facilities during the 2006 test period, meaning that a detailed model would require highly specific and accurate fuel price data to accurately predict aggregate grid behaviour. Though average and daily market fuel prices are available, these data lack either the temporal resolution or site-specific details required for the model to reliably reproduce historical behaviour. For example, many power plants will purchase fuel using bilateral contracts, meaning that published daily market prices are not necessarily identical to real prices paid by power plant operators.

Table 1. The fuel and CO₂ prices below enable satisfactory model agreement between calculated and historical data for ERCOT and GB.

Parameter (units)	ERCOT	GB
Average annual coal price (USD/MMBTU)	1.48	3.49
Average annual natural gas price (USD/MMBTU)	6.60	6.56
CO ₂ price before/after April 26 (USD/tCO ₂)	0	33.58/17.20

The lack of power plant data and inadequacy of published fuel price data necessitated a calibration procedure where coal price, natural gas price, power plant availabilities, and heat rates were adjusted until model results achieved satisfactory agreement with historical electrical and CO₂ output by plant type. Once input parameters are determined, the model functions the same for GB as with ERCOT. Section 5.4 describes the estimation of plant performance parameters in detail, and section 5.3 discusses calibrating coal and natural gas prices. Published values of generation-weighted average efficiency for coal-based and NGCC units in the UK provide an additional metric to assess the validity of chosen power plant performance parameters.

5.3. Fuel and CO₂ prices

In this paper, model studies of ERCOT use average 2006 prices for coal and natural gas from the US EIA for all hours in a study year (table 1) [22]. Coal prices are quite stable in ERCOT, and though natural gas prices are volatile, gas-fired facilities generally remained more expensive than coal- and nuclear-based facilities regardless of gas price variations in 2006.

GB coal prices are also relatively stable compared to natural gas prices, but effective coal prices are higher due to exposure to international coal markets. Therefore, the model uses a constant GB coal price set to 25% above the value reported in DUKES in order to achieve successful agreement with historical generation data [10].

DUKES reports a 7.67 USD/MMBTU annual average UK natural gas price in 2006, but reproducing seasonal fuel-switching requires varying natural gas prices over the year [10]. Daily gas prices are reported by the Intercontinental Exchange (ICE), but contract variability such as bilateral contracts at other prices could produce a different effective natural gas price. Satisfactory calibration is achieved by setting the natural gas price in each month equal to 77% of that month's average ICE front month futures price. Calibrated gas prices vary between 5.20 USD/MMBTU in August and 10.79 USD/MMBTU in January, with an annual average of 6.69 USD/MMBTU [23]. These monthly natural gas prices were used as inputs when estimating power plant performance parameters. After finalizing power plant input data, a new set of input natural gas prices was created that maintains accuracy with historical data while using a single low 'summer' price in April–September and a high 'winter' price on all other days. This two-price representation is then used in comparative analysis because it facilitates easier interpretation of model

results. With these inputs, 2006 GB natural gas costs 7.65 USD/MMBTU in the winter and 5.48 USD/MMBTU in the summer, for an annual average of 6.56 USD/MMBTU.

There was no CO₂ emissions price in ERCOT in 2006 and there is still none today, so no CO₂ emissions penalty exists when comparing calculated and historical data for ERCOT. In contrast, the UK used a voluntary emissions trading scheme from 2002 until operating under the mandatory European Union emissions trading scheme (EU-ETS) since January 2005 [24]. CO₂ prices have been volatile since the inception of the EU-ETS and fell substantially in late April 2006 [25]. To approximate historical 2006 UK CO₂ prices before and after the April 2006 price crash when calibrating GB fuel prices and plant performance parameters, CO₂ prices are set to 33.58 USD/tCO₂ from 1 January 2006 to 26 April 2006 and 17.20 USD/tCO₂ for the rest of 2006 [25].

5.4. Base power plant performance parameters

For both ERCOT and GB, marginal generation costs of non-fossil fuelled-power plants are specified using values from the Nuclear Energy Institute (NEI), International Energy Agency (IEA), and EIA [26–28]. NEI data are also used for fossil fuel-based power plant O&M costs not attributed to fuel or CO₂.

As in previous work, the EPA eGRID database provides heat and CO₂ emissions rates for ERCOT fossil fuel-based power plants [12]. Historical capacity factors are used to establish average availability for coal- and nuclear-based plants, which traditionally serve base load. Average available capacity of gas-fired facilities is assumed to be 80% of rated capacity based on model calibration and commonly cited values, and average availability was calibrated to 19% for hydroelectric and 32% for the wind-dominated ‘other’ category [27, 29]. EPA data from 2004 are updated using capacity installation reports from the Public Utility Commission of Texas. New facilities are assumed to use mature technology, so they are given performance parameters typical of other ERCOT plants of the same type [9].

The DUKES report lists all UK power plants but only specifies maximum rated capacity. Therefore, availability factors, heat rates, and CO₂ emissions rates must be estimated for GB power plants. All fossil fuel-based facilities are assumed to have 85% availability for this first-order analysis, following an approach adopted by the IEA [27]. Availabilities of non-fossil-based plants were adjusted during the calibration procedure to final values of 78% for nuclear, 55% for hydroelectric, and 40% for wind. For each of these plant types, capacity and availability factors should be similar because nuclear and renewable capacity typically provide base load generation. DUKES reports capacity factors of 69% for nuclear, 33% for hydroelectric, and 43% for wind, so calibrated availability factors are accepted as reasonably close while achieving satisfactory calibration [10]. A larger discrepancy for hydroelectric generation is expected because pumped storage hydroelectric facilities are excluded from the model.

All GB coal-fired facilities use similar technology, so their heat rates are assumed to follow a uniform distribution. The distribution range is then adjusted during calibration to 9.5–10.2 MMBTU MWh⁻¹ (33.4–35.9% lower heating value efficiency). CO₂ emissions rates at coal-fired facilities are specified from the linear relationship between heat rate and CO₂ emissions rate correlated from all US coal-based facilities in the eGRID database. For the US fleet, heat rate is not well-correlated with rated capacity or installation date, so instead of assigning the lowest heat rates to the newest or largest GB facilities, performance is pseudo-randomly assigned by matching plant names in alpha-order with heat rates from smallest to largest [12]. A uniform distribution of heat rates for gas-fired facilities did not produce satisfactory calibration results, so heat rates for NGCC and NGGT facilities are instead assigned by first assuming that the heat rate probability distribution is the same in GB and the US. Heat rates for GB NGGT facilities are assumed to follow the same performance distribution as US facilities. The GB heat rate distribution for NGCC facilities, however, was uniformly shifted slightly down to improve agreement between calculated and historical output, CO₂ emissions, and average efficiency. Linear relationships between heat rate and CO₂ emissions rate among US facilities are again used to specify CO₂ emissions rates for NGCC and NGGT plants. NGGT performance is assigned using the same alpha-order matching process as with coal-fired generators. However, NGCC performance was specified by matching the lowest heat rates with the largest output capacities. Though this approach deviates from procedures with coal-based and NGGT facilities, the alternative matching process improves model accuracy significantly. Gas-fired CHP facilities are assumed to always produce their average available capacity, and oil-fired facilities are seldom used in GB, so their performance specifications have little effect on results. Therefore, heat and CO₂ emissions rates for gas-fired CHP and oil-fired facilities are uniformly distributed between the 25th and 75th percentiles of all US plants of that type, and alpha-ordered matching is employed.

5.5. CO₂ capture systems

All CO₂ capture systems are assumed to use 7 molal monoethanolamine (MEA) that removes 90% of the CO₂ from flue gas and requires an equivalent work of 0.269 MWh per metric ton of CO₂ captured at full load [6]. With this illustrative performance, full-load CO₂ capture at selected ERCOT and GB coal-fired facilities reduces net output by 21–26% and CO₂ emissions rates by 86–87%. More efficient facilities achieve lower CO₂ emissions rates and output penalties with full-load capture, but efficiency point reductions are comparable across facilities because they all have the same equivalent work for CO₂ capture. In each hour, flexible CO₂ capture systems can choose between 0% and 100% load, where ‘load’ defines both the fraction of full-load stripping steam and the CO₂ removal rate as a per cent of the full-load removal rate. As an approximation, no residual energy penalty is assumed for 0% load CO₂ capture, but average fixed operating and maintenance (FOM) costs of CO₂ capture are still incurred for

Table 2. Calibrated input parameters yield good agreement between estimated and actual aggregate generation and CO₂ (in million metric tons—Mt) by plant type, especially for base load generation. Historical ERCOT CO₂ emissions are from 2004 because 2006 data were unavailable.

	Calculated ERCOT generation (TWh)	Historical ERCOT generation (TWh)	% Difference	Calculated GB generation (TWh)	Historical UK generation (TWh)	% Difference
Coal	115	116	−1.0%	136	142	−4.2%
Natural gas	146	144	+1.7%	125	138	−9.8%
Nuclear	42	42	+0.6%	69	69	−0.0%
All other	7.8	8.7	−10.6%	21	25	−17.3%
Total	311	311	+0.2%	350	374	−6.4%

	Calculated ERCOT CO ₂ emissions (MtCO ₂)	Historical ERCOT CO ₂ emissions (MtCO ₂)	% Difference	Calculated GB CO ₂ emissions (MtCO ₂)	Historical UK CO ₂ emissions (MtCO ₂)	% Difference
Coal	119	121	−1.8%	120	126	−4.6%
Natural gas	69	73	−6.5%	51	51	+0.1%
Total	188	197	−4.9%	171	183	−6.3%

flexible capture systems at 0% load. Though actual facilities will likely have a nonzero minimum capture load to maintain thermal conditions necessary for rapid return to full load, 0% minimum load is chosen here because previous work found infrequent switching between minimum and full-load CO₂ capture under most electricity market conditions when the base plant is operating [7]. The model, however, can be used with a nonzero minimum load.

With the assumed performance parameters, the largest capture-specific O&M costs are attributed to solvent degradation, maintenance of CO₂ capture equipment, and CO₂ transport and storage. Degradation loss is assumed to be 1.5 kg MEA per tCO₂ captured at a solvent price of 2.36 USD/kg MEA [19, 30]. Maintenance costs are assumed to be 2.2% of the CO₂ capture capital costs of 908 USD per kilowatt (kW) averaged over the total possible annual electrical output with CO₂ capture at full load [31, 32]. CO₂ transport and storage cost is assumed to be 9.08 USD/tCO₂ captured [31]. Based on operational experience with thermal cycling of power system components, flexible systems are also conservatively estimated to have 20% higher capture system maintenance costs. This average maintenance cost penalty adds 4–5 USD MWh^{−1} to marginal costs of electricity production.

As in previous analysis, CO₂ capture scenarios assume that slightly more than half the coal-based capacity in each grid, eight plants each, are retrofitted with CO₂ capture (8.6 GW in ERCOT, 14.6 GW in GB). This degree of capture retrofitting is not meant to be predictive; it is meant primarily to establish conditions for which the grids can be compared with substantial CO₂ emissions reductions from CO₂ capture. ERCOT retrofits are chosen based on which plants have the lowest total capital and operating costs of CO₂ capture. More efficient facilities will have lower short-run marginal costs, and facilities already using sulfur dioxide (SO₂) removal systems can avoid installing SO₂ scrubbers at the same time as CO₂ capture to mitigate amine solvent degradation by SO₂ in flue gas [30]. Land availability and proximity to storage is expected to be a minor issue in ERCOT because facilities are remotely located, and Texas has substantial and geographically varied

CO₂ sequestration capacity [33]. Conversely, proximity to a suitable CO₂ sequestration site is a primary consideration in the UK, so CO₂ capture retrofits for GB coal-fired facilities are chosen based on proximity to the North Sea, the likely primary sequestration location for the UK.

6. Results

6.1. Validation

Table 2 compares model results with historical data using the calibrated input parameters described in section 5. Historical generation and UK CO₂ emissions are from 2006 [10, 11]. ERCOT total annual CO₂ emissions data are from 2004 because 2006 data from eGRID were unavailable, but CO₂ emissions and plant emissions rates are expected to be similar in both years because changes in electricity demand, available power plants, and fuel prices were too small to greatly affect dispatch patterns [11, 12].

In ERCOT, annual generation of all major plant types is calculated within 2% accuracy of historical data. Generation of wind, hydro, and miscellaneous peaking facilities is calculated less accurately, but the absolute error of 1.7 terawatt hours (TWh) is considered acceptable given the model’s inability to consider renewable variability and detailed peaking behaviour [7]. Total annual generation is slightly greater in the model because it uses discrete hourly electricity demand instead of actual cumulative demand. Total CO₂ emissions in ERCOT are slightly underestimated primarily due to the discrepancy in natural gas-based CO₂. Gas-based emissions are underestimated while generation is overestimated because the first-order dispatch model utilizes inefficient peaking facilities less often is required in a fully constrained grid.

Generation and CO₂ emissions by plant type are available for the entire UK but not the GB market, so the 6% underestimate of total generation and CO₂ is predominantly attributed to the exclusion of facilities in Northern Ireland and the Scottish Isles. Coal-based generation and emissions are predicted within 5%. Cumulative generation from all gas-fired facilities is underestimated by nearly 10%, but much

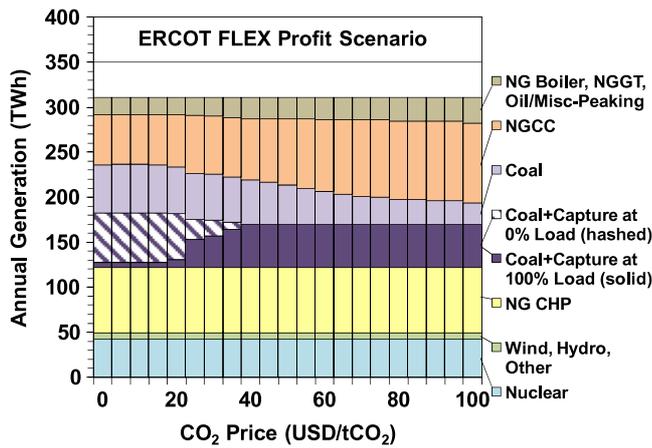


Figure 6. Coal-fired facilities with flexible CO₂ capture are always base load in ERCOT.

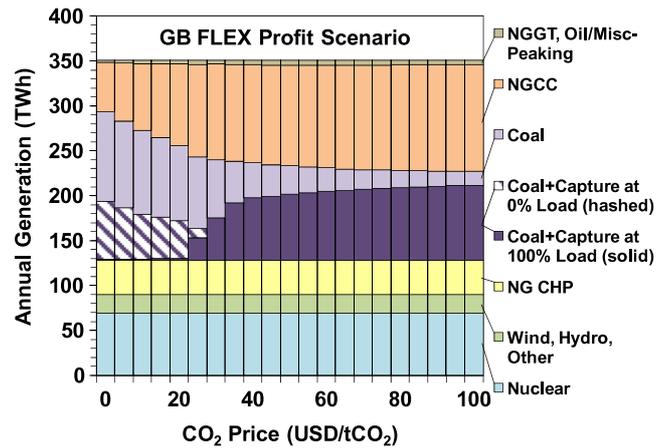


Figure 7. Coal-fired facilities with flexible CO₂ capture are more often intermediate load in GB at lower CO₂ prices.

of the discrepancy is embodied in calculations for gas-fired facilities providing intermediate and peaking load. NGCC generation is predicted within 5% and is a more reliable indication that the model is accurately reproducing seasonal fuel-switching. Confidence is improved by the prediction of generation-weighted efficiencies of NGCC and coal-fired plants within 3%. The discrepancy in accuracy between gas-based generation and CO₂ emissions results from limitations of the first-order dispatch model, difficulty estimating actual plant performance, and the exclusion of facilities that are in the UK but external to the GB market.

6.2. Comparative analysis

Figures 6 and 7 display annual generation by plant type in the FLEX Profit flexible capture scenario for each CO₂ price in the ERCOT (figure 6) and GB (figure 7) grids. These figures are repeated with analogous plots for other scenarios in the appendix. Lighter shaded sections marked ‘coal’ represent output at facilities that do not have CO₂ capture available. The hatched and darker shaded sections designated as ‘coal + capture’ represent output at facilities with CO₂ capture systems; the hatched area denotes output when capture systems are at 0% load, and the solid area indicates output when capture systems are at 100% load.

Nuclear, gas-fired CHP, wind, hydroelectric, and other less common facilities are utilized to meet base load in both grids at all CO₂ prices. In ERCOT, coal-fired facilities with CO₂ capture supply base load at all CO₂ prices, but total output drops from 60 to 48 TWh between 20 USD/tCO₂ and 40 USD/tCO₂ as CO₂ capture operation becomes economical and net output decreases due to the energy requirement of CO₂ capture. The threshold CO₂ price to justify CO₂ capture operation is far below that required to justify building the CO₂ capture systems because electricity dispatch is based primarily on operating costs and does not generally reflect capital costs [6]. ERCOT coal-fired facilities without CO₂ capture become significantly more expensive to operate as CO₂ prices increase, so their output falls with CO₂ price as they are

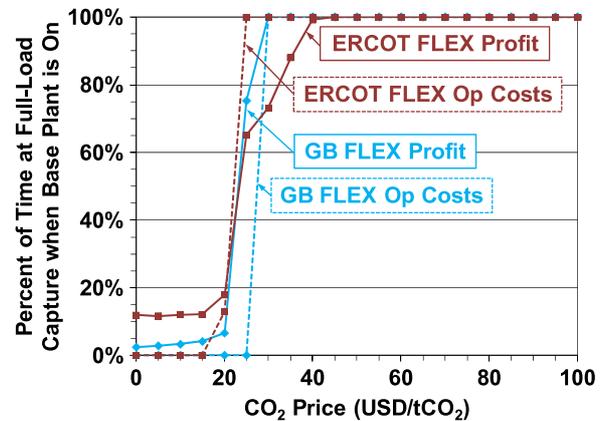


Figure 8. A higher CO₂ price is required for marginal generation costs to be lower with full-load CO₂ capture in GB, because higher coal prices increase the incremental costs of CO₂ capture. These results indicate that flexibility to improve profits would be utilized more frequently in ERCOT.

displaced in the dispatch order by NGCC facilities and coal-fired plants with CO₂ capture.

In GB, coal is more expensive, gas-fired facilities are more efficient on average, and there is more coal-based capacity to compete with, so coal-fired facilities with CO₂ capture are comparably later in the dispatch order than their ERCOT counterparts. As a result, these facilities are often used as intermediate load at low CO₂ prices, so their calculated annual output is far less than the maximum possible. CO₂ capture operation then becomes economical above 20 USD/tCO₂, and annual output approaches 85.6 TWh at high CO₂ prices, the maximum possible with continuous full-load CO₂ capture. Being later in the dispatch order also allows greater displacement of coal-fired facilities without CO₂ capture by NGCC facilities and coal-based plants with capture, especially at moderate to high CO₂ prices.

Figure 8 demonstrates how CO₂ capture utilization changes with CO₂ price by plotting the per cent of time facilities with CO₂ capture operate at full load when the base

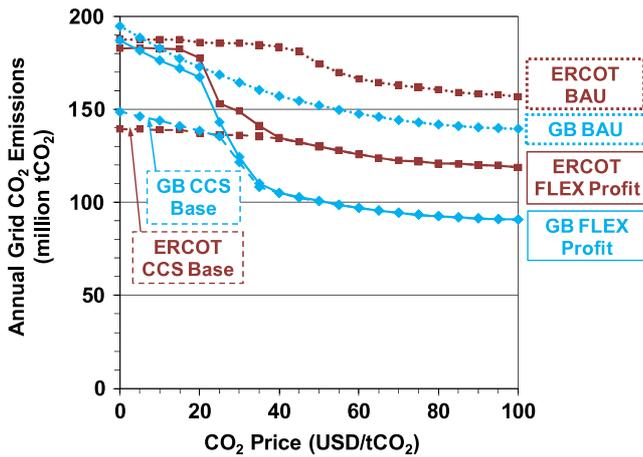


Figure 9. CO₂ emissions are greater in GB with no CO₂ price, but emissions reductions are greater in GB due to more CO₂ capture capacity and fuel-switching from coal to natural gas.

plant is dispatched. The dashed FLEX Op Costs curves show that in ERCOT, 20–25 USD/tCO₂ is required for marginal generation costs to be lower with full-load CO₂ capture. A slightly higher 30 USD/tCO₂ price is required for GB facilities before emissions cost savings offset the higher energy cost of CO₂ capture brought about by higher coal prices.

In the FLEX Profit scenario for ERCOT, facilities use full-load CO₂ capture 12% of the time below 20 USD/tCO₂ because there are times when withholding 1.8 GW output to operate CO₂ capture actually raises electricity prices enough to offset the costs of operating CO₂ capture. Though this practise might seem manipulative, CO₂ emissions are lower than if capture operation were based on operating costs alone. At 25–40 USD/tCO₂, ERCOT facilities in the FLEX Profit scenario also find times when additional electricity sales at zero-load CO₂ capture offset increased CO₂ emissions costs.

There are far fewer times when GB facilities in FLEX Profit use full-load CO₂ capture to raise electricity prices at 20 USD/tCO₂ or below, but at 25 USD/tCO₂, they do so 75% of the time they operate. Above 25 USD/tCO₂, GB facilities in FLEX Profit never use zero-load CO₂ capture to temporarily increase power output, implying that there might be less opportunity in GB to increase power output while venting additional CO₂. However, the first-order modelling methodology does not reproduce extreme peak prices that can far exceed marginal costs, and these prices can be important for flexible capture in both ERCOT and GB.

Though these results imply that flexible operation is unimportant at CO₂ prices high enough to justify investing in CO₂ capture equipment, data still reveal conditions when flexible systems could improve profits in a market with significant electricity and CO₂ price volatility. The EU-ETS market has certainly been volatile in the past [25]. In addition, other modes of flexible operation that allow a temporary increase in power output without increased CO₂ emissions could be valuable across a broader range of CO₂ prices, but analysing these configurations is beyond the scope of this work [34, 35]. Understanding the value of flexible operation

is also important for implementing any additional incentives designed to encourage the use of CCS when prevailing CO₂ prices are not sufficient to justify its use.

Total grid CO₂ emissions at each CO₂ price are shown in figure 9 for the BAU, CCS Base, and FLEX Profit scenarios. Even without CO₂ capture (BAU), emissions decrease with CO₂ price as coal-fired facilities are displaced by gas-fired plants. At 100 USD/tCO₂, fuel-switching from coal-to-gas reduces CO₂ emissions by 16% in ERCOT and 28% in GB relative to the 0 USD/tCO₂ case. Fuel-switching is more prevalent in GB than ERCOT because coal-based facilities appear later in the dispatch order than they would in ERCOT for a given CO₂ price.

Inflexible CO₂ capture (CCS Base), where all flue gas must be treated at plants where CCS has been installed, substantially reduces CO₂ emissions at any CO₂ price. For a given CO₂ price, CO₂ emissions relative to BAU are 24–35% lower in GB and 24–27% lower in ERCOT; however, GB emissions reductions at low CO₂ prices are primarily because coal-fired facilities with inflexible CO₂ capture are not dispatched. Though GB’s greater coal-based capacity results in higher BAU emissions at 0 USD/tCO₂, CO₂ capture achieves much greater emissions reductions at high CO₂ prices because CO₂ capture is retrofitted to about 6 GW more coal-fired capacity than ERCOT.

CO₂ emissions in FLEX Profit are only slightly lower than BAU at low CO₂ prices when facilities sometimes use full-load CO₂ capture to withhold output and raise electricity prices. CO₂ emissions then approach the CCS Base curve at 30–40 USD/tCO₂ when full-load CO₂ capture becomes economical. CO₂ emissions are greater with flexible CO₂ capture at low CO₂ prices, but substantial emissions reductions occur at any CO₂ price high enough for marginal generating costs to be lower with full-load CO₂ capture.

Plotting average annual electricity price versus each CO₂ price (figure 10) indicates the relative frequency that electricity prices are set by gas- or coal-based facilities without CO₂ capture. The slope of the curve represents the average CO₂ emissions rate of price-setting facilities, so a slope near 0.5 (USD/MWh)/(USD/tCO₂) indicates that gas-fired plants most commonly set electricity prices, and a slope nearer to 1 (USD/MWh)/(USD/tCO₂) signifies more frequent price setting by coal-based facilities.

In ERCOT, predominance of natural gas means that the ability to capture CO₂ has a small effect on electricity prices for a given CO₂ price. However, CO₂ capture has a larger influence on prices in GB because GB coal-fired facilities more frequently set electricity prices than their ERCOT counterparts. Prices in flexible capture scenarios always fall at or between the BAU and CCS Base curves for a given grid. Electricity prices are higher for CCS Base at low CO₂ prices when the output reduction from CO₂ capture requires the use of more expensive facilities to meet electricity demand. However, prices are lower with CO₂ capture (CCS Base) than without (BAU) at high CO₂ prices because high emitting coal-based plants without capture set electricity prices more frequently in the BAU case. Electricity prices are lower in GB for a given CO₂ price because gas-fired facilities are more efficient on average

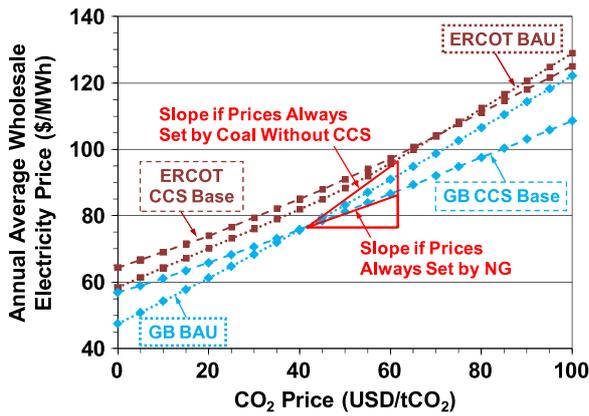


Figure 10. Wholesale electricity prices are similar across CO₂ capture scenarios, but prices are generally lower in GB.

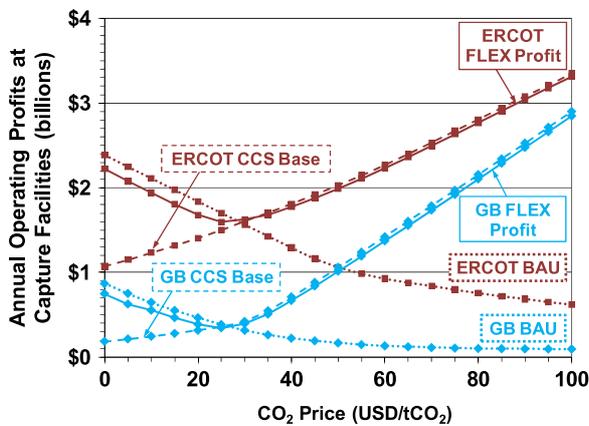


Figure 11. Profits at facilities considered for CO₂ capture are lower in GB due to lower electricity prices and less frequent dispatch at lower CO₂ prices. Assumed maintenance costs of flexibility negate the benefits of flexibility below 35 USD/tCO₂.

than their ERCOT counterparts. Though actual average 2006 electricity prices were 6.5 USD MWh⁻¹ higher in GB than ERCOT, GB had a significant CO₂ price from its participation in the EU-ETS, so lower electricity prices in GB than ERCOT are expected for an equivalent CO₂ price [25, 36, 37].

The profit implications of inflexible (CCS Base) and flexible (FLEX Profit) CO₂ capture are compared to the no-capture scenario (BAU) in figure 11, which plots annual before-tax operating profits for the facilities considered for CO₂ capture. Despite greater output capacity of the GB plants, profits are always lower in GB because calculated electricity prices are lower. Electricity prices and profits may be more comparable if realistic electricity price volatility and extreme peak prices were included, but the first-order model does not reproduce such behaviour. In addition, operating profits are lower for GB facilities due to a number of factors. They are dispatched less often than their ERCOT counterparts due to higher coal prices and because on average, GB gas-fired facilities have higher efficiency than similar ERCOT facilities. A further consideration is that UK capture retrofits were selected by storage proximity rather than base plant

efficiency, so the selected UK plants have lower average base plant efficiency than the retrofitted plants in ERCOT. However, these results only address dispatch economics, and retrofit selection in both ERCOT and GB will be a more complex investment decision. The slope of a profit curve depends on the plants' emissions rates relative to those of the average price-setting facilities, so BAU profits fall monotonically and CCS Base profits rise monotonically as CO₂ price increases. Curves begin to level off for BAU at high CO₂ prices because coal-fired facilities are setting prices more often. Profits with flexible CO₂ capture are lower than BAU at low prices and lower than CCS Base at high prices due to the assumed 4–5 USD MWh⁻¹ maintenance cost of flexibility; profits are highest in FLEX Profit only in ERCOT at 30 USD/tCO₂. Absent this maintenance cost penalty, profits would be highest with flexible CO₂ capture below 40 USD/tCO₂, but the added maintenance costs are enough to offset any potential benefits. Any operating cost penalty of flexibility should be minimized, but these results do not discount the value of flexible CO₂ capture in either grid. The first-order electricity market model does not reproduce realistic electricity price volatility and short-lived high electricity price spikes that could be very profitable for flexible capture systems. These effects are addressed in other work and will be studied more in the future [34, 38].

7. Conclusions

A first-order electricity market model formerly used exclusively for the ERCOT electric grid has been successfully adapted to study CO₂ capture in GB. After input data calibration, results are within 6.5% of historical generation and CO₂ emissions for power plant types used primarily to meet base and intermediate electricity demand.

If half of coal-based capacity in each grid is retrofitted with CO₂ capture (8 GW in ERCOT and 14 GW in GB), the model estimates that coal-fired facilities with CO₂ capture would serve primarily base load for 0–100 USD/tCO₂ prices in ERCOT but would be intermediate load in GB below 40 USD/tCO₂. In GB, there is greater parity between coal- and gas-fired facilities because coal is more expensive, gas-fired facilities are more efficient on average, and coal-based facilities make up a greater fraction of total capacity. As a result, coal-fired facilities with CO₂ capture appear later in the dispatch order at low CO₂ prices, and coal-fired facilities without CO₂ capture are displaced by NGCC and CO₂ capture facilities to a much greater extent than in ERCOT at high CO₂ prices. These market characteristics and the additional 6 GW of assumed CO₂ capture retrofits in GB allow for much greater CO₂ emissions reductions in GB than ERCOT from coal-to-gas fuel-switching and CO₂ capture operation. Fuel-switching at 100 USD/tCO₂ in the absence of CO₂ capture achieves a 16% grid CO₂ reduction in ERCOT and 28% in GB relative to the 0 USD/tCO₂ case, and reductions can be as great as 37% in ERCOT and 53% in GB with 100 USD/tCO₂ and half the coal-based capacity retrofitted with CO₂ capture.

Average wholesale electricity prices in both grids are influenced more by market CO₂ price than CO₂ capture operation, particularly for CO₂ prices where electricity prices are normally set by gas-fired power plants. CO₂ capture, therefore, has a greater effect in GB where coal-fired facilities more often set electricity prices. Electricity prices are higher when CO₂ capture operates at low CO₂ prices because the output reduction from CO₂ capture requires the use of more expensive generating facilities, assuming no new capacity is installed to offset the energy requirements of CO₂ capture. However, electricity prices are lower with CO₂ capture than without above 70 USD/tCO₂ in ERCOT and 40 USD/tCO₂ in GB when coal-based generators without CO₂ capture frequently set electricity prices. Electricity prices are generally lower in GB because gas-fired facilities are more efficient on average than their ERCOT counterparts. A number of factors including lower electricity prices and intermediate-load dispatch mean that the coal-fired plants considered for CO₂ capture earn lower operating profits in GB despite having greater overall capacity.

In ERCOT, marginal generation costs at coal-fired facilities are lower with full-load CO₂ capture above 20–25 USD/tCO₂. About 30 USD/tCO₂ is required in GB for CO₂ capture to provide emissions cost savings that offset incremental CO₂ capture costs at higher UK coal prices. In ERCOT, there is substantial opportunity for flexible capture to improve operating profits by using full-load CO₂ capture to withhold output and raise electricity prices below 20 USD/tCO₂ and zero-load CO₂ capture to increase output and emit additional CO₂ at 25–35 USD/tCO₂. However, operating profit improvements could be offset if flexibility adds 5 USD MWh⁻¹ to operating costs. CO₂ emissions might be greater with flexible CO₂ capture at low CO₂ prices, but substantial emissions reductions are achieved in both grids at any CO₂ price high enough for marginal generation costs to be lower with full-load CO₂ capture. The value of flexible CO₂ capture in response to demand-following electricity prices appears limited under the conditions studied, but a conclusive assessment must incorporate realistic electricity price volatility and the potential to earn payment for grid reliability services.

Acknowledgments

The authors gratefully acknowledge discussions with colleagues that have improved their understanding of the GB and ERCOT electricity systems, including Prof Jon Gibbins and Dr Gary Rochelle. SC also acknowledges support from the United States Environmental Protection Agency (EPA) Science to Achieve Results (STAR) Graduate Fellowship Program and the Luminant Carbon Management Program. Additionally, HC acknowledges financial support from the UK Energy Research Centre (www.ukerc.ac.uk) and the UK Foreign and Commonwealth Office Science and Innovation Network. The views expressed within this publication might not reflect the views of any sponsoring organizations.

Appendix. Generation by plant type for all scenarios

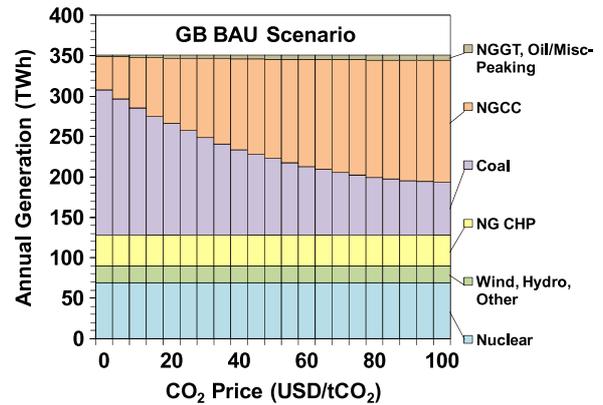


Figure A.1. Each column represents generation by plant type for Great Britain at a specified CO₂ price in the BAU scenario.

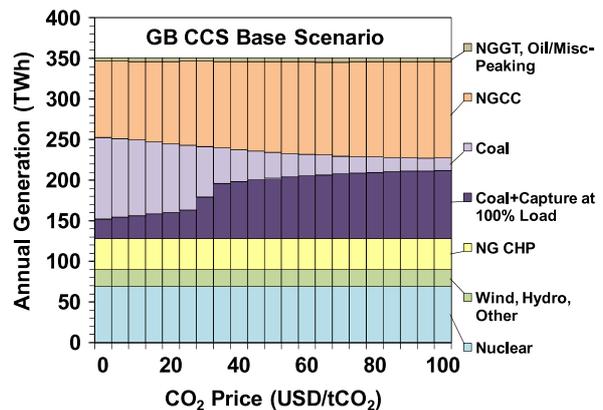


Figure A.2. Each column represents generation by plant type for Great Britain at a specified CO₂ price in the CCS Base scenario.

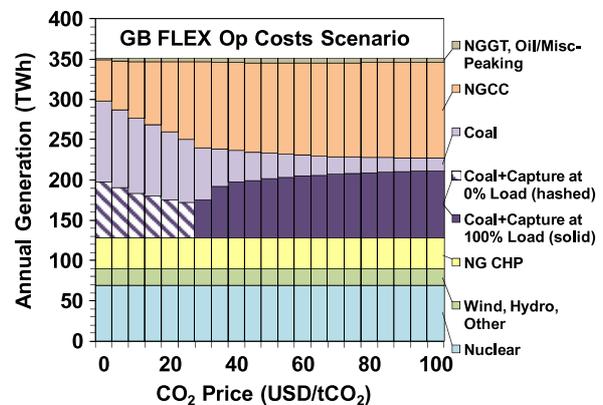


Figure A.3. Each column represents generation by plant type for Great Britain at a specified CO₂ price in the FLEX Op Costs scenario.

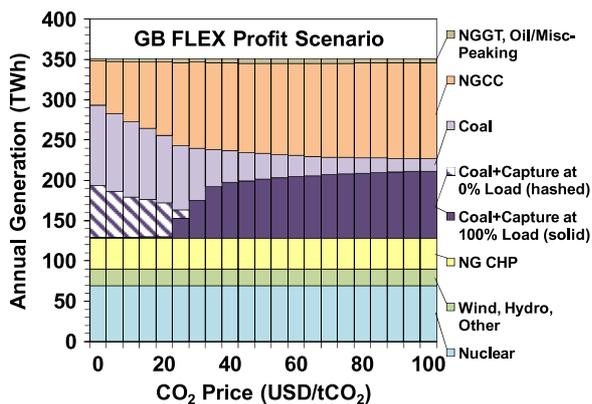


Figure A.4. Each column represents generation by plant type for Great Britain at a specified CO₂ price in the FLEX Profit scenario.

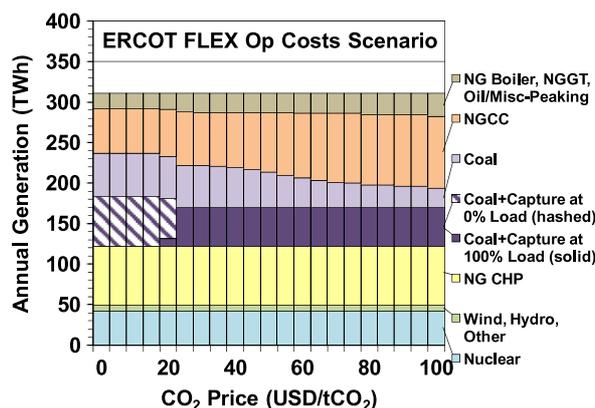


Figure A.7. Each column represents generation by plant type for ERCOT at a specified CO₂ price in the FLEX Op Costs scenario.

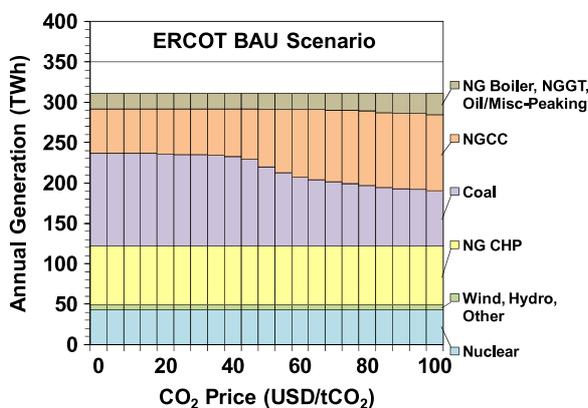


Figure A.5. Each column represents generation by plant type for ERCOT at a specified CO₂ price in the BAU scenario.

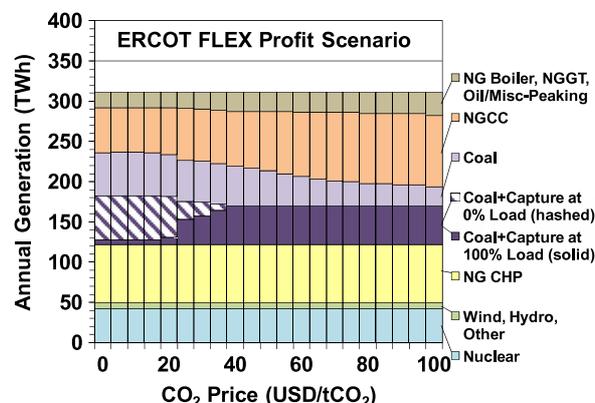


Figure A.8. Each column represents generation by plant type for ERCOT at a specified CO₂ price in the FLEX Profit scenario.

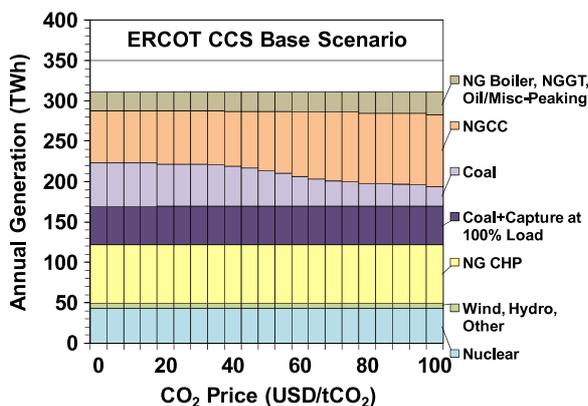


Figure A.6. Each column represents generation by plant type for ERCOT at a specified CO₂ price in the CCS Base scenario.

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