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Developing a Supply Curve for CO_2 Capture, Sequestration and EOR in the UKCS: an Optimised Least-Cost Analytical Framework

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Research in North Sea Economics has been conducted in the Economics Department since 1973. The present and likely future effects of oil and gas developments on the Scottish economy formed the subject of a long term study undertaken for the Scottish Office. The final report of this study, The Economic Impact of North Sea Oil on Scotland, was published by HMSO in 1978. In more recent years further work has been done on the impact of oil on local economies and on the barriers to entry and characteristics of the supply companies in the offshore oil industry.

The second and longer lasting theme of research has been an analysis of licensing and fiscal regimes applied to petroleum exploitation. Work in this field was initially financed by a major firm of accountants, by British Petroleum, and subsequently by the Shell Grants Committee. Much of this work has involved analysis of fiscal systems in other oil producing countries including Australia, Canada, the United States, Indonesia, Egypt, Nigeria and Malaysia. Because of the continuing interest in the UK fiscal system many papers have been produced on the effects of this regime.

From 1985 to 1987 the Economic and Social Science Research Council financed research on the relationship between oil companies and Governments in the UK, Norway, Denmark and The Netherlands. A main part of this work involved the construction of Monte Carlo simulation models which have been employed to measure the extents to which fiscal systems share in exploration and development risks.

Over the last few years the research has examined the many evolving economic issues generally relating to petroleum investment and related fiscal and regulatory matters. Subjects researched include the economics of incremental investments in mature oil fields, the impact of the Gas Levy on incremental investments in mature gas fields, economic aspects of the CRINE initiative, economics of gas developments and contracts in the new market situation, economic and tax aspects of tariffing, economics of infrastructure cost sharing, the effects of comparative petroleum fiscal systems on incentives to develop fields and undertake new exploration, the oil price responsiveness of the UK petroleum tax system, and the economics of decommissioning, mothballing and re-use of facilities. This work has been financed by a group of oil companies and Scottish Enterprise, Energy Group.

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1. Introduction

Carbon capture and storage (CCS) is a sequential combination of processes involving the separation or capture of carbon dioxide (CO_2) from combustion sources such as boilers, turbines and heaters; its transportation in pipelines or tankers, injection and storage in geological formations.

Most of the technologies involved at the different stages are mature at least in some applications but not in the UKCS. Both in industrial and petroleum processing, CO_2 has routinely been separated from other industrial and hydrocarbon gases to purify the gas stream. The separation is normally carried out by physical or chemical means. Similarly, the petroleum industry has a long history of transporting natural, compressed and uncompressed gases. To date, however, there is little experience worldwide, including the UKCS, with the integrated CCS chain.

Viewed as a series of linked processes, CCS has three main cost centres corresponding to the links in the chain. Each cost centre has its own investment and operating costs as well as revenue-earning potential. The present study seeks to establish an appropriate framework for determining the least-cost option for each stage of the CCS value chain.

2. The CO_2 Capture Stage and Costs

CO_2 capture refers to the production of a

> *"concentrated stream of CO_2 at high pressure that can be readily transported to a storage site" (IPCC, 2005).*

There are diverse sources of CO_2 emissions and potential capture, but it is generally agreed that the most economic capture sources in the UK are the large stationary plants or point sources, emitting roughly a minimum of 0.5 $MtCO_2$ per annum[1]. Typically, these point sources include electricity-generating plants, refineries, iron and steel plants, ammonia and cement factories. The present study concentrates on fossil-fuel-fired power plants[2] in the UK and installations in the UKCS.

CO_2 separation can be undertaken with either of 2 established technologies namely, post-combustion amine scrubbing or pre-combustion decarbonisation of hydrogen. The third alternative technology – oxyfuel combustion- is still at the demonstration stage. The processes have their relative cost advantages, depending on the operating environment.

There are many power plants in the UK, with most of them currently ageing. It is expected that, given the UK's commitment to reducing CO_2 emissions as agreed under the Kyoto Protocols and the EU Burden

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[1] There are 57 sites in the UK with emissions in excess of 1 $MtCO_2$ per annum, with the largest source being the Drax power plant on Humberside emitting 16.4 $MtCO_2$ per year.

[2] The fossil fuel-fired plants generate about 140 Mt CO_2/year (AEA Technology, 2005)

Sharing Agreement, the new power plants to replace or augment the ageing power plants will be designed to be either "capture-ready", or at least, having "with capture" facilities[3]. In the meantime, any existing power plants undertaking CO_2 capture will have to retrofit[4] their boilers to perform the additional task of CO_2 capture. Retrofits and new builds differ in their costs, construction phase duration, and, project life. However, whether retrofitted or new-build, the investment in a CO_2 capture system is an extra investment undertaken by an emission-regulated[5] power plant that has to decide whether or not to meet any reductions in its annual CO_2 emission allowance[6] via carbon capture[7]. That decision is based principally on a comparison of the cost of emission reduction with the cost of emission compliance. The power plant owners must determine the cost curve of its emission reduction project by itself in order to make the comparison. The route to determining the firm's cost curve lies in first solving the complex problem of determining the least-cost combination of inputs. Conventionally, the power plant obtains the least-cost combination of inputs by minimising its production costs subject to a number of constraints, dictated by its operational and regulatory environment.

[3] Indeed, there are already at least 4 new generation "CCS-friendly" power plants being planned to go on stream in the near future. These include the proposed RWE's 100MW clean coal power plant at Tilbury, Essex; E.ON's 450MW coal-fired plant with CCS on the Lincolnshire coast; the Progressive Energy's 1000MW IGCC plant on the Teesside; and, BP'S 350MW NGCC plant at Peterhead.

[4] It is noted, "some studies suggest that retrofitting an amine sembler to an existing plant results in greater efficiency loss and higher costs. A more cost-effective option is to combine a capture system retrofit with re-building the boiler and turbine to increase plant efficiency and output" (Spalding, 2005).

[5] Regulated under the UK's Statutory Instrument 2003 No. 3311 (or The Greenhouse Gas Emissions Trading Scheme Regulations 2003). Schedule One operators under the Regulations are penalised for "excess emissions"(33)(1)(2)(3). The current "excess emission penalty" is 40 Euro per tonne.

[6] One emission allowance confers the right to emit one tonne of CO_2 (EU ETS, 2005)

[7] With the ETS (emission trading scheme) starting in the 25 EU Member States as from January 1, 2005, the firm could alternatively have chosen to meet the required reduction in emission through either output reduction or carbon trading.

An important element of the operational environment is the structure of the market in which the CCS value chain is realised. It is possible to have a market structure that is predominantly vertically integrated, or one that is predominantly non-integrated, with several autarkic operators. In the parlance of the UK ETS[8] (2005), the latter market structure is said to be dominated by Single or Direct Participants while Group Participants dominate the former. There is, also, the special case of Direct Participants who being fully integrated vertically have management control over CO_2 capture, transport and storage processes. Both market structures and operator types will be modelled in the present study, starting with the Direct Participants market.

3. Non-Integrated (Direct Participants-Dominated) Market

In the autarkic market scenario, it is assumed that different firms, operating independently of each other engage in the capture, transportation and storage of CO_2. In the present study, the typical Direct Participant firm engaged in CO_2 capture is assumed to be an electricity power plant. At the other end of the CCS chain, an oil and gas producing company is assumed to be the typical CO_2 end-user deploying CO_2 for EOR. Linking together the two sets (i.e. CO_2 producer and end-users respectively) of Direct Participants are one or more "Trading Participants", who are engaged in CO_2 shipment and/or trading.

[8] The national ETS "competent" authority in the UK under Article 18 of Directive 2003/87/EC establishing the EU ETS.

3.1 Electricity and CO_2 production

The objective function:

An implicit production function is assumed to exist establishing the technical relationships between the inputs and outputs of electricity generation and CO_2 capture. Multiplying the inputs by their respective prices yield the production costs which are the main focus of the present study. An important cost component in the universally emerging carbon abatement regime is the costs of compliance with CO_2 emission caps and/or emission reduction.

Being a Schedule One operator under the GHG ETS Regulations 2003 the emission-regulated owner of a CO_2 point source (such as an electricity-generating power plant), is assumed to have the corporate goal of minimising its emission compliance cost by engaging in and minimising the cost of CO_2 capture. The objective of minimising the present value of the firm's total cost can be stated more formally as:

$$\textbf{Minimise: } \sum_{t=1}^{T} \delta_t \left[Z_{ct} \right] \qquad (1)$$

where:

δ_t *= the discount factor =* $1/(1+r)^t$ *(%)*

r *= is the discount rate (%)*

Z_{ct} *= the total cost of electricity production and* CO_2 *capture (£million)*

The formulation in equation (1) includes a discount factor to underscore straightaway the fact that the present study is interested in the long-term costs and revenues of the CCS value chain. As such, it should be understood henceforth that even when the time subscript is dropped for convenience, the study is concerned with the present value and not the undiscounted values of the model variables.

The objective function will be minimised given the firm's operating environment under the assumptions discussed below.

The underlying assumptions

The following assumptions are made about the operating environment of the capture plant.

(i) **Emission:** The power plant emits substantial amounts of CO_2. The emissions are related to the carbon content of the fuel used, and, therefore, easily calculable as[9]:

$$CO_2 \text{ emission} = \text{Activity rate } \times \text{ emission factor}$$

(ii) **Technology:** The CO_2 is captured with either pre- or post-combustion technology[10].

(iii) **2-product firm:** Commercialising the captured CO_2 adds value to the gaseous by-product of electricity production, making the power plant a 2-product firm. Compared with a power plant without a CO_2 capture system, the "with-capture" plant stands to benefit from scope economies on account of its multi-product status.

(iv) **Common, joint and unique costs:** Common, joint and unique costs of electricity and CO_2 production are incurred in the capture process. The common costs would include the capital cost of the production infrastructure. The joint costs are the

[9] See (AEA Technology (2005)

[10] The decarbonised hydrogen produced in the pre-combustion process is not treated as an end product but as an input in electricity generation. It is noted that decarbonised hydrogen has several uses including being used as fuel and feedstock in ammonia and fertilizer production.

costs of raw materials and other variable inputs[11]. Joint costs are incurred only up to the "split-off" point in the production process[12]. Beyond the split-off point, unique additional costs are incurred in finishing and/or getting each product ready for the market. In the case of carbon capture, these costs would include the costs of the solvents etc used in separating CO_2 from the rest of the gas stream.

(v) **Effects of Learning by doing:** Historically, any first-of-its-kind plant usually turned out to be the most expensive. Conventional wisdom holds that learning-by-doing and experience lower costs. CO_2 capture on the envisaged scale is new in the UK. However, it is hoped that through "learning-by-doing" capital and operating costs will be reduced over time. Indeed, according to the IPCC (2005),

> *"...the literature suggests that, provided R and D efforts are sustained, improvements to commercial technologies can reduce current CO_2 capture costs by at least 20 – 30 % over approximately the next ten years, while new technologies under development could achieve more substantial cost reductions".*

(vi) **Primary fuels:** Coal, gas, and petroleum coke could be used as the primary fuel in generating electricity and CO_2. The fuel type and fuel costs are significant cost elements.

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[11] This view is consistent with Hawkins (1969) who described joint costs as "those costs incurred when the production of one product simultaneously and necessarily involves the production of one or more other products………… common costs are incurred when products can be separately produced with the same or part of the same facilities, but need not be produced together."

[12] For example, in pre-combustion capture, the "split-off" point occurs at the point where the CO_2 is separated from hydrogen, which is then used to generate electricity, and/or for other purposes (see Fig. 1).

(vii) **A market for CO_2:** Both national and international markets are assumed to exist for the CO_2 captured in the UK. At least some of the captured CO_2 will be delivered for use in such value-added applications as EOR[13] (enhanced oil recovery), EGR (enhanced gas recovery), or pressure support[14] in the producing oil and gas fields of the UKCS. The depleted oil and gas fields of the UKCS can also be used for the permanent storage of CO_2, which may not be traded nationally and internationally under the UK/EU ETS. The conventional wisdom is that the vibrancy of the CO_2 market would depend on the stringency of carbon abatement rules.

(viii) **Price effects and competition:** The quantities of electricity and CO_2 produced and sold are functions of their costs and prices. It is recognised that in CO_2 EOR deployment, CO_2 may face competition from alternative technologies.

The model

The cost components of a power plant producing electricity and CO_2 comprise:

(a) A common capital cost for infrastructure, plant and machinery.

(b) Joint variable costs of electricity and CO_2 production.

(c) Unique variable cost of electricity production.

(d) Unique variable cost of CO_2 production. And,

(e) The cost of non-delivered emission allowance (NDEA)[15]

[13] UKCS reservoirs have been screened by the DTI for their suitability for CO_2 for EOR (Riley, 2005).

[14] Releasing or substituting for natural gas which, having a burn-value can be traded.

[15] where NDEA is defined as:

NDEA = Annual emission ***less*** annual emission allowance

The common cost

The common cost is the fixed or capital cost of procuring the infrastructure, plant and machinery required to produce electricity and CO_2. There are different types and sub-types of fossil fuel-based power plants, each distinguished by the particular fuel used, level of operational efficiency, optimum operating size, expected life expectancy, and the steam and pressure conditions (i.e. sub- or supercritical boilers). The differences translate to significantly different project costs.

As such, the common capital cost of electricity and CO_2 production may be described as being dependent on the plant type, plant size, efficiency, location[16], the cost of financing capital and the load and scale factors. In symbols,

$$K_c = k_c\ (Q_{X1}, l, i, v, e, g)^{17} \qquad (1)$$

where:

K_c = *CAPEX of the power plant (£million)*
Q_{X1} = *the notional plant size for electricity production (in MW)*
l = *the load factor (% of Q_{X1})*
i = *the rate of interest (%)*
v = *the scale factor*
e = *the efficiency factor*
g = *other indirect factor cost*

[16] That is, inland or near-shore. Power plants requiring seawater for flue gas desulphurization are better located near-shore.
[17] All the variables are flows measured per unit of time.

The joint variable raw materials and other costs:

The variable costs (or OPEX) are typically expended on the procurement of raw materials and other expenses. Some of the costs can be attributed uniquely to either electricity or CO_2 while others are allocated jointly to the two products. The expenditure on fuel represents the most important joint cost, since any fuel (coal, gas or oil) used at this stage of the CCS value chain can produce two saleable products namely, electricity and CO_2. The total and joint fuel costs can be derived as:

Total fuel cost $= F = {}_f\,(Q_X) = F_1 + F_2$

$F_j = f_j\,(Q_{Xi}) \qquad j = i \ \ (i = 1,2)$ (2)

where in addition to previous definitions:

F = *the total cost of fuel for electricity and* CO_2 *production*

F_j = *the cost of fuel for producing the jth product*

Q_{X2} = *the amount of* CO_2 *captured (Mt* CO_2*/annum)*

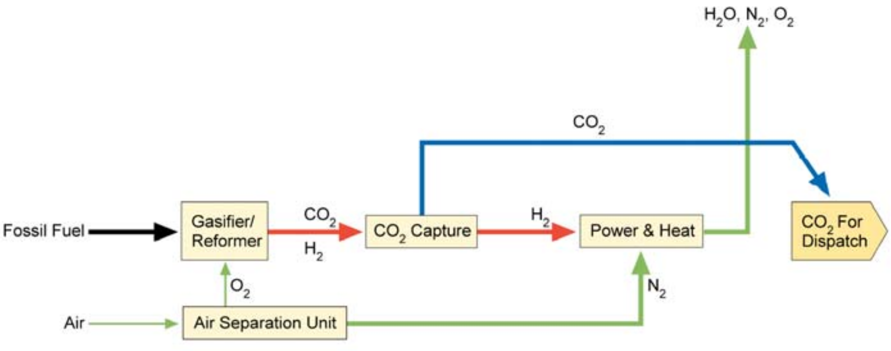
j = *index of joint cost (1 =electricity; 2 =* CO_2*)*

In other words, the total fuel cost is the sum of the respective share of the fuel cost of producing electricity and CO_2. The fuel costs are functions of the respective outputs to which they contribute in producing.

The unique variable costs

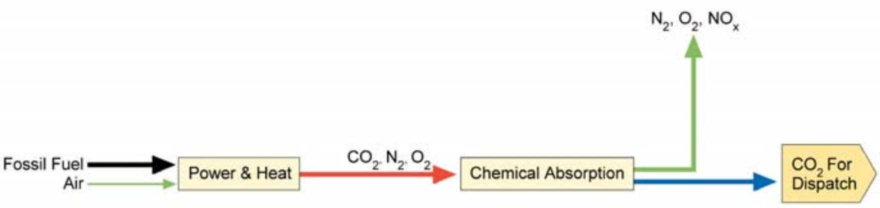
The unique costs are the costs incurred at and beyond the "split-off" point to produce electricity and CO_2 respectively. Figs 1 and 2 below respectively describe the pre- and post-combustion technologies for CO_2 capture, pinpointing the "split-off" points in CO_2, electricity and hydrogen production. The unique costs of CO_2 will include the costs of solvents, membranes or solid sorbents (e.g. limestone) used in separating CO_2 from the rest of the gas stream.

Fig. 1: Capture – Pre Combustion



Source: Marsh (2005), Carbon capture and Storage (CCS) – Drivers and Technologies

Fig. 2: Capture – Post Combustion



Source: As Fig. 1

The unique costs (U_1 and U_2) are functions of the respective output of the product to which they refer. That is,

Total unique cost is $= U = U_1 + U_2$ (3)
where:
$U_1 = u_1 (Q_{X1})$ = *the cost of electricity production beyond the split-off point.*
$U_2 = u_2 (Q_{X2})$ = *carbon-related costs beyond the production split-off point*

U_2 is the endogenously determined cost of emission reduction and is an important decision variable. It is the cost that has to be compared with the cost of compliance with emission caps in order for CO_2 capture to be undertaken or dropped. The rational power plant will engage in CO_2 capture only if the cost of capture is less than the cost of compliance. In symbols, the investment criterion can be derived as:

$U_2 < Y$ (4)
where:
Y = *the penalty for non-delivered emission allowance*

The emission penalty or, the compliance cost *Y,* is the product of the market price of emission allowance and *E*, the non-delivered emission allowance. Hence,

$Y = y(P_e, E)$ (5)
where:
P_e = *the market price of emission allowance*
E = *excess emission or NDEA*

As an entry in the total cost equation, the significance of expression (4) is that both U_2 and Y must appear together as a net quantity. The inclusion of only the gross values of U_2 or Y is misleading. However, the manner of entry of the net variable into the cost function is of paramount importance. There are 2 possibilities. Terminologically, the cost function of an emission-regulated firm would include either a *net emission penalty* or, a *net emission reduction* cost component. That is, the emission-related component of the cost function would be either,

$$\text{Net cost of emission penalty} = Y - U_2 \tag{6}$$

or,

$$\text{Net cost of emission reduction} = U_2 - Y \tag{7}$$

A positive equation (6) implies that Y (the compliance cost) is greater than U_2 (the cost of emission reduction). Therefore, it pays to engage in carbon capture. But, a positive equation (6) would ***add*** to the total cost function of electricity generation and carbon capture, while a negatively signed equation (6) will ***reduce*** it but is inadmissible[18]. Besides, a positive equation (6) in the long-run is counterintuitive, if, as is hoped, the cost of CO_2 capture (U_2) *reduces* over time (i.e. $U_2 \rightarrow 0$ *as* $t \rightarrow \infty$) and that of Y *increases* over time, as should happen, if increasingly stringent emission allowances are imposed to effectively discourage CO_2 emissions.

By contrast equation (7) is admissible only if it is negative (i.e. compliance cost exceeds capture cost). The negative sign is consistent with the expected long-term trends of the cost of compliance and CO_2 capture cost. Therefore, inserting the equation in the total cost function

[18] No rational investor would engage in carbon capture if the capture cost exceeded the penalty.

will ***reduce*** the short- and long-term cost of electricity generation and CO_2 capture.

It is worth emphasising, therefore, that in a carbon abatement regime, the appropriate emission-related cost to consider and include in the total cost function is the net cost of emission reduction. A simple numerical example can be used to demonstrate this point. Assume two time periods, Period 1 and Period 2. The firm's total cost can be split broadly into emission-related and other costs. The other costs and the amount of CO_2 captured are constant in both periods at £100 and 1 tCO_2 respectively. Further, assume that in Period 1, the values of Y and U_2 are respectively £20/tCO_2 and £10/tCO_2. In Period 2, the values of Y and U_2 are doubled and halved respectively, assuming the simultaneous occurrence of a stricter emission regulation regime and R&D-induced cost-reductions. The emission-related costs in the two periods are summarised as follows:

Period	**Total cost with Net emission penalty cost ($Y–U_2$)**	**Total cost with Net emission reduction cost (U_2-Y)**
1	110	90
2	135	65

The example clearly shows that using the net emission reduction cost is more accurate.

In summary, the OPEX (i.e. operating expenditures) of the electricity-generating and CO_2 capture plant can be written as:

$$V_c = v_c\ (F\ (Q_{X1},\ +\ Q_{X2},),\ u1\ (Q_{X1}),\ N\ (Q_{X2},\ P_{X2})) \qquad (8)$$

where,
V_c = the OPEX of the electricity-generating and CO2 capture plant £m)
N = the net cost of emission reduction

Piecing together the various total cost components identified thus far, and, dropping the time subscript for convenience, the firm's aggregate cost function can be written as:

$$Z_c = z_c\ (K_c,\ V_c) \qquad (9)$$

Thus, the cost function in equation (9) states that the CO_2-capturing power plant's total cost is determined by the firm's:

(i) fixed capital cost
(ii) joint fuel cost
(iii) unique cost of electricity production
(iv) net cost of emission reduction[19]

It is noteworthy that equation (8) refers only to the cost of electricity generation and CO_2 capture at the plant boundary site. The costs of delivery to end-users are not included.

Furthermore, equation (8) is a generalised cost function to the extent that it can be applied to a new or an existing power plant that is retrofitted with a new or upgraded boiler. In the modelling, retrofitting will be a

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[19] An alternative measure that could have been used is the cost of CO_2 avoided, where the amount of CO_2 avoided is defined as:
CO_2 avoided = quantity of CO_2 captured ***less*** the extra quantity of CO_2 emitted in the capture process
Using the cost of CO_2 avoided is appropriate where the focus is on a comparison of the relative costs of alternative carbon abatement technologies. The focus of the present study, being to develop an appropriate analytical framework for a successful CCS value chain, is different. Hence the use of the net cost of emission reduction.

special case of the equation, focusing only on the ***incremental*** capital and operating expenditures. This implies that some of the cost elements in the equation will be zero, leaving the cost of the capture plant as the main incremental capital outlay.

When optimised with the appropriate constraints (see below) equation (8) would simultaneously yield the optimal production and cost allocation schedules of the joint products (electricity and CO_2).

By partially differentiating equation (8) with respect to Q_{X1} (electricity generation) and Q_{X2} (CO_2), the respective marginal costs of electricity generation and carbon capture can be obtained. Dividing the equation by Q_{X1} and Q_{X2} will yield the average costs of CO_2 capture.

On the revenue side, the power plant will be selling two products – electricity and CO_2. The quantity sold of either product is assumed to be a function of its price. That is,

$$Q_{X1}=q_1\ (P_{X1});\ QX2 = q_2\ (P_{X2}) \qquad (10)$$

where:
P_{X1} = *the price of electricity*
P_{X2} = *the price of* CO_2

And, the individual revenues from the sale of electricity and CO_2 respectively are:

$$TR_1 = Q_{X1}\ x\ P_{X1}\ ;\ TR_2 = Q_{X2}\ xP_{X2}$$

Therefore, the power plant's pre-tax profit can be described as:

$$\pi_c = [TR_c\ (TR_1 + TR_2) - Zc)] \qquad (11)$$

In maximising profit (equation (11)) or minimising cost (equation (9)) a number of factors and/or constraints, including the following must be borne in mind:

(1) **Minimum outputs**: There would be the need to produce minimum outputs of electricity and CO_2 to meet anticipated demands as and when required.

(2) **Demand constraints:** Firstly, the demand for CO_2 in the UKCS will arise from its use in EOR, EGR, ECBM, and for pressure support in producing oil and gas fields. Since the demand is "derived", it would be contingent on the performance of the oil and gas markets and reservoirs. Secondly, the "demand" for CO_2 may arise for deployment in permanent storage to meet corporate and/or national obligations under the Kyoto Protocol or the UK/EU CO_2 emission-related Directives. Demand for CO2 for permanent storage may be constrained, therefore, by the performance of the overall economy or the economic growth rate.

(3) **Technical/technological constraints:** Electricity generation and CO_2 capture could be constrained by the choice of technology, determining issues such as the performance and size of the optimum plant as well as the duration of the project's development phase.

3.2 CO_2 Transportation

The divergence in the locations of CO_2 capture and its deployment for EOR or permanent storage naturally necessitates its transportation. In general, there will be *m* sources of CO_2 and *n* destinations each requiring the commodity. Several modes of CO_2 transportation have been identified in the literature. These include pipelines, sea-going tankers, and rail and road tankers.

The investor is assumed to be interested in adding value to the captured CO_2 by gathering the gas from the *m* capture plants and delivering either to permanent storage or EOR end users at the *n* different locations. The investor may act as a shipper or a trader in CO_2. Whichever way he acts, the investor will enter the UK/EU ETS as a Trading Participant.

As a rational service provider the Trading Participant will seek to minimise the PV (present value) of his operational costs. Therefore, the transport cost minimisation problem can be stated in general terms as:

$$Minimise: \sum_{t=1}^{T} \delta_t \left[\sum_{i=1}^{m} \sum_{j=1}^{n} z_{ij_t} Q_{X2ij_t} \right] \qquad (12)$$

where in addition to previous definitions:

z_{ij} = *the cost of transporting 1 unit of CO_2 from the ith source to the jth destination.*

Q_{X2ij} = *the quantity of CO_2 shipped from the ith source to the jth destination.*

To carry on his business, the investor incurs capital and operating expenditures while deriving revenue from the shipment or sale of CO_2. Essentially, the investor's capital cost would be the cost of providing the necessary transport infrastructure, the core of which is expected to be a network of pipelines. Rail and road tankers may be used to transport the CO_2 from a power plant to a terminal, when it may not be commercially viable to extend a pipeline to directly gather the CO_2 from the power plant. The overall cost of CO_2 transportation is influenced by the adopted mode or modes of transportation.

CO_2 may be transported either in existing pipelines (including the re-use of pipelines of the fields no longer in production), or new-build pipelines. The existing pipelines, typically made of carbon-manganese steels, are more suited to transport dry CO_2, which is not corrosive. More expensive pipelines made from corrosion-resistant steel alloys would be required to transport the highly corrosive moisture-laden CO_2.

For a new-build pipeline network the capital cost of a pipeline will depend on the distance to the oil field, the terrain, the capacity of the pipeline, the material or type of steel and corrosion protection used, the pipe-laying cost. The capital cost of the pipeline infrastructure and ancillary equipment may be represented as:

$$K_p = k_p\,(D, C, T, G, L) \qquad (13)$$

where in addition to previous definitions:

K_p = *the capital cost of the pipeline infrastructure (£ million)*
D = *distance (km)*
C = *capacity (mass flow rate) of the pipeline (MtCO_2/year)*
T = *pipeline material cost/ price of steel (£million)*
G = *cost of compressors (£million)*
L = *pipe-laying cost (£million)*

The total cost of CO_2 transportation (Z_s) is obtained by adding the variable cost to equation (13). The variable cost specifics depend on the exact nature of the business. The Trading Participant may engage itself principally either as merchant or a shipper. Either way, the operator's variable cost will largely be determined by the amount of CO_2 it handles. As a merchant, it would buy CO_2 from the capture plant and re-sell to end-users for either EOR or permanent storage. The pipeline OPEX in this case would include the cost of the CO_2, energy (γ) or fuel used in the transportation and other administration charges (β) process.

$$V_{p1} = v_{p1}\ (\gamma,\ \beta,\ (Q_{X2}\ xP_{X2})) \tag{14a}$$

As a shipper, on the other hand, while fuel costs (γ) would still be included in the OPEX, the cost of the CO_2 transported would not. That is,

$$V_{p2} = v_{p1}\ (\gamma,\ \beta)) \tag{14b}$$

Accordingly, in transporting CO_2 from *m* capture points to *n* destinations, the total cost of the CO_2 trader and shipper are described respectively as:

$$Z_{s1} = z_{s1}\ (K_p,\ V_{p1}) \tag{15a}$$
$$Z_{s2} = z_{s2}\ (K_p,\ V_{p2}\gamma) \tag{15b}$$

In other words, the cost of CO_2 transport is assumed to be a function of:

(a) the fixed capital cost
(b) the cost of energy used in transportation
(c) the cost of CO_2
(d) the administration charges

Equation (15b) is easily seen as a special case of equation (15a) where: $(\mathbf{Q}_{X2}\ \mathbf{xP}_{X2}) = 0$

Also, it is easily seen that the trader's total CO_2 cost or payments are the total revenues of the CO_2 capture plant.

The Trading Participant may earn his income in either of two ways, as a CO_2 shipper or trader. In the former case, its revenue will be the pipeline tariffs paid by the CO_2 end users for delivering their orders from the capture plant. As a trader, the investor will earn his revenue through the sale of CO_2 to the end users. In either case, the operational revenue depends on the amount of CO_2 sold or shipped. The firm's profit as a trader is described as

$$\pi_{s1} = Q_{X2} \times P^{p}_{X2} - Z_{s1} \qquad (16a)$$
$$\pi_{s2} = Q_{X2} \times R_{X2} - Z_{s2} \qquad (16b)$$

where in addition to previous definitions:
P^{p}_{X2} = delivered price of CO_2, (P_{X1} + margin)
R_{X2} = the pipeline tariff for shipping CO_2

The profit function in equation (16) or the transport cost in equation (12) will be optimised subject to a number of constraints including the following:

Transport constraints:

(a) Total CO_2 required at the *n* destinations must equal the total supply from the *m* capture points.

(b) Also, there may be limits on the state of the CO_2 to be transported (i.e. moisture-laden or dry) and the strength of material (e.g. expensive corrosion-resistant alloys or the cheaper carbon manganese steel for pipelines

3.3 CO_2 Injection and EOR Costs

It is assumed that the investor or Direct Participant at this stage of the CCS chain is an end user of CO_2, interested in using the gas to enhance oil and/or gas production.

The first step in the EOR process is CO_2 injection. CO_2 must be injected under pressure through an injection well into a rock formation. Usually, the injection will be to a depth exceeding 800 metres (IPCC, 2005). Existing wells may be re-used as injectors but new ones may have to be drilled, where re-use is not a viable option. The amount injected will depend on the storage capacity of the reservoir and the rate and duration of injection. That is,

$$A = a\ (V, I, I_d) \qquad (17)$$

where:
A = *the amount of* CO_2 *injected* ($MtCO_2$*/year)*
V = *storage capacity of the reservoir*
I = *the rate of injection*
I_d = *the duration of injection*

The cost of injection will depend largely on the amount of CO_2 injected and other factors. Accordingly, the injection cost function may be written as:

$$O_e = o_e\ (H, W, A) \qquad (18)$$

where, in addition to previous definitions:
O_e = *the injection cost*
H = *the reservoir depth*
W = *the water depth*

Constraints to injection cost minimisation

As with the rest of the CCS chain, it is assumed that the corporate goal is to minimise the cost of CO_2 injection subject to a number of constraints. Two of the constraints impacting on injection and storage costs are worthy of mention. Firstly, there is the problem of the availability of suitable storage sites. Several issues pertaining to the suitability of geological formation for permanent CO_2 storage have been raised in the literature. A particular requirement is that the geological formation must have a well-sealed cap rock that would ensure the permanent entrapment of the injected CO_2 underground for centuries.

Secondly, there is the problem of adequacy of the storage potential. There are considerable uncertainties regarding the amount of CO_2 that would need to be stored under the Kyoto Protocol and EU Burden Sharing Agreement and the potential geological storage capacity. However, the results of several site characterisation surveys carried out to date indicate that the UKCS potentially has ample geological storage capacity.

Table 1[20]: Potential CO2 Storage Capacity Under North Sea (BGS project

Theoretical Capacity Gt CO_2					
Country	**Gas**	**Oil**	**Confined Aquifers**	**Open Aquifers**	**Totals**
Denmark	0.46	0.13			
Netherlands	0.82	0			
Norway	7.19	3.1	10.85	476	497.14
UK	4.88	2.62	8.56	240	256.06
TOTALS	**13.35**	**5.85**	**19.41**	**716**	**754.61**

Source: Riley, 2004

Table 1 shows the estimated potential geological storage capacity of the UKCS. The capacity can be compared with the UK emissions in 2001, which were estimated to be 0.55Gt CO_2 of which roughly 36% (or about 0.2Gt CO2) was emitted by the country's power plants (Riley, 2004).

EOR

In deploying CO_2 for EOR two possible technologies have been identified in the literature. The technologies are the WAG (Water Alternating Gas) and the GSGI (Gravity Stabilising Gas Injection). Both differ in their

[20] According to Riley "More detailed mapping since 1995 suggests that UK confined aquifer storage theoretical capacity is in excess of 70Gt CO2

costs, project duration, and, the amount of CO_2 injected per barrel of incremental oil output[21]. Cost-wise, it is generally agreed that WAG is cheaper than the GSGI and is, therefore, likely to be adopted first in the UKCS. However, whichever technology is assumed, modifications may need to be made to the existing installations, including topside facilities before CO_2 for EOR can commence.

$$K_e = k_e\,(O_e, M_d) \qquad (19)$$

where, in addition to previous definitions
K_e = *the expected incremental CAPEX (£million)*
M_d = *platform modification costs (£million)*

The cost of the platform modification and ancillary equipment, such as separation facilities for produced oil, water, and CO_2, will constitute the incremental capital cost.

The level of the incremental OPEX will be determined by the cost of the delivered CO_2 and other costs outlined below.

$$V_e = v_e\,(D_e, \alpha) \qquad (20)$$

where in addition to previous definitions
V_e = *the expected incremental field OPEX (£million)*
D_e = *the delivered* CO_2 *cost,* $P^p_{X2} \times Q_{X2e}$ *(£million)*
α = *non-CO2-related OPEX (£million)*

Accordingly, the cost of CO_2 for EOR at the platform can be summarised as:

$$Z_e = z_e\,(K_e, V_e,) \qquad (21)$$

where in addition to previous definitions:
Z_e = *the cost of* CO_2 *for EOR (£million)*

[21] Tzimas **et. al.** (2005) identified Miscible and Immiscible CO_2 EOR operations and pointed out that "immiscible displacement projects would generally require a higher amount of injected CO_2 per increment barrel of oil produced, typically two to three times more". (p. 58)

Equation (21) incorporates the theory that the CO_2 injection cost, the levels of the incremental capital expenditure, expected incremental OPEX and delivered cost of CO_2 together determine the overall cost of CO_2 at the platform. The major component of the incremental capital cost is the cost of platform modification and ancillary equipment. While the bulk of the incremental field OPEX would consist of non-CO_2-related expenditures on the wages bill, maintenance, insurance and (non-CO_2) fuels, the delivered cost of CO_2 is a significant component of the incremental field OPEX (Tzimas **et al.**, 2005). However, since the level of operations determines the magnitudes of the various cost components, it follows that ultimately,

$$V_e = v_e (Q_{X3}, Q_{X2e}) \tag{22}$$

where in addition to previous definitions
Q_{X3} *= the incremental oil output (mmboe)*
Q_{x2e} *= the quantity of CO_2 deployed in EOR ($MtCO_2$/year)*

That is, the incremental OPEX is largely determined by the level of the incremental oil production and the amount of CO_2 deployed in EOR. The delivered cost of CO_2, is the product of the delivered carbon price and the required amount of CO_2 (i.e. $P^p{}_{x2}$ x Q_{X2e}). The presence of Q_{X2e} in the expression naturally leads to demand side considerations.

On the demand side, the quantity demanded of CO_2 for EOR can be described as:

$$Q_{x2e} = f\,(RFL, RRR, P^p{}_{X2}, P_a, P_{eo}, Q_{X3}, W) \tag{23}$$

with the conditions that:

$$d\,(Q_{X2e})/d\,(RFL) < 0 \quad d(Q_{X2e})/d(P^p{}_{X2}) < 0$$

$$d\,(Q_{X2e})/d\,(P_a) > 0 \quad d(Q_{X2e})/d(P_{eo}) > 0$$

where in addition to previous definitions:
RFL = B = the remaining field life[22] *(years)*
RRR =R = the remaining recoverable reserves (mmboe)
P_a *= the price of alternative technology/fuel for EOR (£)*
P_{eo} *= the expected oil price (£)*
Q_{X3} *= the incremental oil output (OOIP x recovery factor) (mmboe)*
W = the injection-production time lag (years)

Equation (23) states that the quantity of CO_2 demanded for EOR is determined by the perceived EOR potential (i.e. RFL and RRR), the expected price of oil, the price of alternative technology, the incremental oil output and the injection-production time lag.

The EOR potential has one volume and two time dimensions. The time dimensions are driven by geology and technology. The geology-driven time dimension is captured by *RFL* or *B* (remaining field life or time-to-the decommissioning date). *W* or the injection-to-production time lag, captures the technology-driven time dimension in the equation. Not being instantaneous, the choice of technology influences the duration of the time lag between the commencement of injection and the production of the first incremental oil. Thus, for instance, the WAG injection technology has a shorter time lag than GSGI[23].

The quantity dimension of the EOR potential is captured by RRR (remaining recoverable reserves), which is defined as:

RRR = R = OOIP – cumulative oil production

[22] The remaining field life is the time from the time date of analysis to the decommissioning date.
[23] Also, Tzimas **et. al** (2005) demonstrated that miscible CO_2 injection technology has a shorter time lag than immiscible injection technology.

However, the influence of the EOR potential on the amount of CO_2 deployed for EOR is bi-directional. That is, the amount of CO_2 deployed influences the EOR potential as well. So that,

$$B = b(Q_{X2e});\ d(B)/d(Q_{X2e}) > 0$$
$$R = r(Q_{X2e});\ d(R)/d(Q_{X2e}) > 0$$

Thus, CO_2 EOR potentially extends the remaining field life of oil and gas assets and the amount of remaining recoverable reserves. Extending the remaining field life is tantamount to prolonging the field decommissioning date. The extensions or postponement of the decommissioning date are very beneficial as revenues are earned from the sale of the incremental oil and gas. Clearly, the postponement of the decommissioning date can be extremely valuable to the operator and the Exchequer. However, there are geological and technological limitations to the improvement to recovery rates and field life extension or the postponement of the decommissioning date achievable through CO_2 EOR. But, until those limits are reached, more CO_2 EOR will postpone the decommission date and improve the recovery factor[24].

In addition to the physical EOR potential, the demand for CO_2 for EOR is determined by three prices – that is, the delivered price of CO_2 (P^p_{X2}), the price of the alternative technology (P_a) and the expected oil price (P_{eo}).

[24] Several authors estimate enhanced recovery factors of between 4 and 12 percent (see, for example, Tzimas **et. al.**

The demand for CO_2 for EOR is determined by the amount of anticipated incremental oil output. Two important points must be borne in mind concerning the technical input-output relationship of the incremental oil and CO_2. Firstly, estimates vary as to how much incremental oil can be obtained per tonne of CO_2 injected[25].

Secondly, the relationship is not linear. The amount of CO_2 injected to enhance oil recovery varies over the field life, especially as the CO_2 can increasingly be split between "fresh" and "recycled". Specifically, the amount of CO_2 required for EOR declines over time as succinctly described in Bellona (2005),

> *"After a period of CO_2 injection, and CO_2 "breakthrough" occur (when the CO_2 start coming back to the surface with oil and gas production), the oil and gas will contain CO_2 (i.e. the produced well stream will contain increasing amounts of CO_2). The produced CO_2 in the oil/gas is separated and thereafter reinjected in the field. The result is that the field's need to purchase fresh CO_2 may be gradually reduced as more and more of the CO_2 injected is actually produced from the oil reservoir itself. This is a technical decision that would be based on production increases from the field…"*

[25] Timms (2005) and Bellona (2005), for example, cited 1 tCO_2 yields up to 3 extra barrel of oil equivalent.

Using the CO_2 EOR function (equation (23)) in equation (21) shows that the generalised CO_2 for EOR cost function, can be written as:

$$Z_e = z_e\ (K_e,\ V_e\ (Q_{X3},\ Q_{X2e})) \qquad (24)$$

In summary, according to equation (24) the cost of EOR is determined by several factors including:

(a) the injection cost
(b) the expected incremental CAPEX
(c) the expected incremental field OPEX
(d) the EOR potential *(B, R, W)*
(e) the delivered price of CO_2
(f) the price or unit cost of the alternative technology
(g) the expected price of oil
(h) the incremental oil output

The dependence of the cost of EOR on the levels of incremental CAPEX and OPEX are straightforward. It is noteworthy that the incremental OPEX would include an on-going monitoring cost to monitor the injection rate, well pressure, seismic surveys[26] and CO_2 leakages (IPCC, 2005)[27].

Naturally, the delivered price of CO_2 (P^p_{X2}) and the unit price of the alternative technology also determine the cost of EOR. Higher CO_2 prices will increase the cost of EOR while lower prices of the alternative technology in competition with CO_2 will reduce it.

Lastly, the expected incremental oil revenue also influences the cost of CO_2 at the platform. The direction of the relationship may be positive. That is, the higher the expected revenue, the higher the cost of EOR.

[26] For tracking the underground migration of CO_2.
[27] The issue of monitoring costs is very important and somewhat complex as it will continue well after the COP (cessation of production). The study will address the issue of who pays the monitoring costs in the post-cessation period.

The profit of the firm may be described as:

$$\pi_e = P_{eo} x Q_{X3} - Z_e - Z_D \qquad (25)$$

where in addition to previous definitions
Z_D = the decommissioning cost (£million)

Equation (25) defines the operator's profit as its total revenue less its costs, which include the expected incremental CAPEX, OPEX, and the cost of decommissioning. Equation (25) or (24) will be optimised to derive the supply cost curve of CO_2-based enhanced oil production. The analysis is consistent with the economic cut-off according to which, EOR activities will continue as long as:

EOR revenues $\geq$ EOR costs

EOR activities will cease at the economic cut-off point when,

EOR revenues = EOR costs

3.4 Permanent Storage

While the scope for using CO_2 for EOR is hopefully substantial, there are still considerable uncertainties about the supply of CO_2 and its demand for EOR. It is likely that, at any point in time, the supply of CO_2 may outstrip its demand for EOR. The excess supply of CO_2 will have to be stored in permanent storage.

No private investor will undertake the permanent storage of CO_2 except where there are positive returns to the investment. There are two possible ways to make the investment in permanent CO_2 storage worthwhile. First, the government may grant incentive payments similar to that implemented under the UK ETS[28], to cover a part or all of the excess CO_2. The payments may be justified as a stakeholder's contribution

[28] The UK ETS was started in 2002 as a forerunner to the EU ETS and covered all the greenhouse gases. Zeroing in on CO_2, the incentive payment in any commitment year was equal to the product of the CO_2 "clearing price" and the recipient's annual target CO_2 emission reduction for the year. For more details of the scheme, see HMSO (2002).

towards meeting the UK's obligations under the Kyoto Protocol and the EU Burden Sharing Agreement. Alternatively, it is possible that a stringent emission allowance regime will be imposed. In a stringent emission allowance regime, emitters will find it relatively difficult to maximally operate within their emission limits, resulting in recourse to the carbon market to buy emission allowances.

Since the market conditions and/or operating environment are assumed to be the same, whether the final destination of the captured and transported CO_2 is in permanent storage or EOR, there would be no need to over flog the underlying reasoning behind the input-output relationships already espoused above in this section of the study.

The capital cost of the permanent storage of CO_2 will include, if appropriate (a) the cost of acquiring the depleted oil and gas reservoir in which the CO_2 will be stored, (b) the injection cost and (c) the cost of the monitoring and remediation equipment. That is,

$$K_{ps} = CAPEX_p = k_{ps}\ (\tau,\ O_p,\ Mp) \qquad (26)$$

where:

K_{ps} = *the capital cost of* CO_2 *permanent storage (£million)*
τ = *the cost of depleted oil reservoir acquisition (£million)*
O_p = *injection cost (permanent storage) (£million)*
M_p = *platform modification costs (£million)*
M_p = *the cost of monitoring and remediation equipment (£million)*

It is assumed that as in the case of CO_2 EOR the variable cost will comprise (a) the expected incremental OPEX, $M_{p,}$ and (b) the cost of the CO_2 injected. That is,

$V_{eps} = v_e\ (D_{ep},\ \alpha_p)$ *(27)*

where in addition to previous definitions

V_{eps} *= the expected incremental field OPEX (permanent storage) (£million)*

D_{ep} *= the delivered* CO_2 *cost,* $P^p{}_{X2} \times Q_{X2e}$ *(£million)*

α_p *= non-CO2-related OPEX (permanent storage) (£million)*

At first, it may seem that, unlike the case of CO_2 EOR, the amount injected into permanent storage does not depend on the oil price, at least, not directly. Nevertheless, it is plausible to postulate that, assuming a common supplier, the CO_2 price will be the same in EOR deployment and permanent storage. Otherwise, it will pay the supplier to shift CO_2 from the lower to the higher marginal revenue market. However, there are some important differences. When CO_2 is destined for permanent storage the influence of factors such as the EOR potential and the level of oil production activities are ignored.

Accordingly, the total cost of CO_2 permanent storage is:

$Z_{ps} = z_p\ (K_{ps},\ V_{ps}\ (Q_{X2eps}))$ *(28)*

where in addition to previous definitions

Z_{ps} *= the total cost of deploying* CO_2 *in permanent storage (£million)*

Q_{X2ps} *= the amount of* CO_2 *injected into permanent storage (MtCO2/year)*

The firm's profit can be described as:

$\pi_{ps} = P^p{}_{X2} \times Q_{X2ps} - Z_{ps}$ *(29)*

Either the cost function (equation (28)) or the profit function (equation (29)) will be optimized subject to the necessary constraints in order to derive the supply curve for CO_2 permanent storage.

***Storage limitations**:*

There will be physical storage limitations in individual reservoirs. The physical constraints impacting on storage costs will include the type (depleted or producing oil and gas reservoir, or deep saline formations) and characteristics of the geological formation (formation thickness, permeability etc), reservoir depth, rock volume and whether offshore or onshore. The costs incurred would relate to (i) the total planned amount of CO_2 to be stored (ii) storage location (iii) the planned rate of injection and, (iv) the commencement date of injection.

3.5 The Total Cost of CCS Chain

It is recognized that, because the products handled in the CCS value chain are differentiated, it is impossible to have one supply curve for the value chain. Nevertheless, for expositional purposes it is possible to crudely add up the separate costs of the different stages of the CCS chain to have an idea of the overall cost of the chain.

The foregoing analysis has revealed that the total cost of the CCS value chain depends on several factors including the final destination of the CO_2 – that is, in EOR applications and/or permanent storage and, the role and market power of the Trading Participants. Thus, the total cost of the CCS value chain would, ***ceteris paribus***, be lower if the CCS chain terminated in permanent storage than in EOR because of the expected lower operational costs in the former case. But, of course, revenues occur directly from the EOR reducing the net cost. Also, where trading confers a higher market power on the Trading Participant, the overall costs would likely be higher because the trader is able to charge higher CO_2 delivered prices to the end-users.

Narrowing down the options to the case in which the Trading Participant acts only as CO_2 shipper, the total cost of the CCS value chain respectively deployed in EOR and permanent storage can be written as:

$$Z_{nv1} = Z_c + Z_{s2} + Z_e \qquad (30)$$

and,

$$Z_{nv2} = Z_c + Z_{s2} + Z_{ps} \qquad (31)$$

where in addition to previous definitions,

Z_{nv1} = *the total cost of the non-integrated CCS value chain with EOR applications*

Z_{nv2} = *the total cost of the non-integrated CCS value chain with permanent storage*

Conceivably, $Z_{nv1} > Z_{nv2}$ since $Z_e > Z_p$ *(by assumption)*

4. Non-Integrated (Group Participants-Dominated) Market

As mentioned above, the market structure of the CCS value chain may be dominated either by one or more individual firms at each stage acting independently to maximize their profits or, by firms that are integrated in varying degrees and direction. The analysis thus far has focused on the former market arrangement.

Conceivably, loosely vertically- or horizontally-integrated companies engaging in the CCS value chain would be admitted as Group Participants in the UK/EU ETS. The opportunity to pool emission allowances is a strong motivating factor in joining a Group. Group Participants are allowed to pool their emission allowances under conditions specified in Article 28 of the EU ETS. In particular, Article 28(3) states that:

> *"Operators wishing to form a pool shall nominate a trustee:*
> *(a) to be issued with the total quantity of allowances calculated by installation of the operators, by way of derogation from Article 11;*
> *(b) to be responsible for surrendering allowances equal to the total emissions from installations in the pool, by way of derogation from Articles 6(2)(e) and 12(3); and*
> *(c) to be restricted from making further transfers in the event that an operator's report has not been verified as satisfactory in accordance with the second paragraph of Article 15."*

Thus, Group Participation is advantageous to the extent that the arrangement permits risk sharing. The integrated CCS value chain is at the experimental stage in the UKCS, with considerable market and technological uncertainties. Pooling together the know-how and financial resources of the individual members of the Group reduce the riskiness of the novel business of carbon capture, transportation and storage.

In terms of modelling, the economics of the CCS value chain in a market dominated by Group Participants is basically the same as that dominated by individual Direct Participants, since the rules and determinants of the cost and revenue streams are the same. The crucial difference lies in resource pricing, arising from the fact that the market and technology risks borne exclusively by the individual Direct Participant are somehow spread among the several members of a Group.

Depending on the Group composition and the feedstock used, the difference in resource pricing will be manifest in Group Participants having:

(a) lower fuel costs in electricity generation and CO_2 capture;
(b) lower delivered price of CO_2 for EOR deployment.

These two costs are central to the profitability or otherwise of the CCS value chain.

5. Vertically Integrated Market

Thus far, the study has considered the two cases in which the emission-regulated firms participate in the UK/EU ETS either as (a) Direct Participants typically situated in a particular sector and engaged in one or the other stage of the CCS value chain; or (b) Group Participants who are loosely integrated vertically or horizontally.

A third possibility is a special case of Direct Participants, in which the operator simultaneously engages in and combines the CO_2 capture, transport and storage processes into one integrated project. Feasible integrated CCS projects make economic sense to the extent that the investor can better spread the inherent market and technological risks among the 3 cost-revenue centres in the CCS value chain. Indeed, arguably, risk spreading is the raison d'etre of fully vertically integrated CCS investments. This is because even in its short history, the market price of the CO_2 allowances under the EU ETS, since the scheme started in January 2005, has been quite volatile and this may be expected to continue. A vertically integrated operation in these circumstances reduces the risks compared to a non-integrated one.

As with the non-integrated Direct Participant, the study assumes that the overarching goal of the integrated Direct Participant is to minimise the total cost of the CCS value chain. Accordingly, the firm's objective function can be stated as:

$$Minimise \quad : \sum_{t=1}^{T} \delta_t \left[Z_{vt} \right] \qquad (32)$$

where, in addition to previous definitions,
Z_{vt} = *the integrated cost of CO_2 capture, transportation, EOR and storage*

The next step is (dropping the time subscript) to derive the total integrated cost Z_{vi} as was done for the non-integrated Z_{nvi} (equations 30 and 31) case. However, since it is assumed that the market and regulatory conditions are the same for the integrated and non-integrated producers, there is no need for another full-blown derivation of the former. However, while the reasoning behind the derivation of Zvi and Z_{nvi} are basically the same, there are no theoretical grounds to expect the magnitudes of the two overall costs to be equal. Specifically, it is arguable that

$$Z_{nvi} > Z_{vi} \qquad (33)$$

That is, the overall non-integrated project cost is likely to be higher than that of the integrated project.

Theoretically, there are, at least, two reasons why the direction of the relationship in equation (33) is likely to be correct. The first is the effect of a project's riskiness on the associated prices. In general, riskier projects engender higher product prices, and producers increase their required rate of return on investments and use higher prices to compensate for risk. In an emerging market such as the CCS value chain, with considerable market and technological uncertainties, standalone projects without the opportunity to recoup losses in one stage of the chain from gains in another will be riskier and, therefore charge higher product prices or service fees will be sought. Adding the higher costs at each stage of the non-integrated CCS value chain together produces a higher overall total cost than that of the integrated CCS value chain which, by definition, are less risky, on account of their ability to spread the project risks among the three cost-revenue centres.

Secondly, even if the integrated and non-integrated CCS value chains were equally risky, the latter would still be costlier because the delivered cost of CO_2, a major component of the overall cost, is higher under this regime. The non-integrated end-users of CO_2 in EOR applications and/or permanent storage, would, at some point rely on the pipeline network of the integrated producers for the delivery of their required CO_2. Because such shipping demand can only be met out of any ullage in the pipeline network, and, on the payment of pipeline tariffs, the arrangement would most likely be more expensive to the non-integrators, raising their overall CCS cost in the medium- to long-term.

6. Conclusions

Both globally and in the UK, there is growing concern about the deleterious effects of global warming caused largely by the emission of greenhouse gases, including CO_2, into the atmosphere. A number of carbon abatement programmes and legislation have either been implemented or are actively being considered, including the CCS value chain. This paper has examined the CCS value chain from an economic perspective and proposed an appropriate analytical framework to determine the least-cost arrangements within the chain.

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