UK ENERGY RESEARCH CENTRE

Response to the Treasury consultation on Carbon Capture and Storage

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Treasury consultation on CCS:
Response by the UK Energy Research Centre

Background

The Chancellor has stated (writing in the Independent 21 April 2006) that "*The environmental challenge must be moved to the centre of policy*". The UK has domestic targets for CO_2 reduction of 20% by 2010, and 60% by 2050. In contrast to these aspirations, CO_2 emissions have fallen by 15%, but are now increasing (DEFRA 2006). Private car fuel costs, with CO_2 emissions, have barely changed since 1985 (85p then to 95p/litre now), and air travel is rising.

If the UK is serious about reducing CO_2 emissions in the short or medium term, then it is clear that existing policies are either not working or are too slow to act.

Electricity generation comprises about one third of UK CO_2 emissions, and so must be seriously considered as a target for large scale emission reductions. The benefits of this are large single-site reductions, compared to wind generation or to efficiency savings. To illustrate the size of this opportunity for CO_2 emissions reduction the BP-Peterhead proposition, for 350MW low carbon electricity with CCS, can be calculated to avoid as much CO_2 as all wind generation active in the UK during 2005

As with any new technology, it is probable that a gradual takeup will occur. This means the construction of full-scale pilot projects is necessary, as a learning process to enable cheaper routine construction. This is the step to be considered now, NOT full-scale routine CCS.

The question could be framed as: "Is now a good enough time to deploy one or several full-scale pilots in the UK?" *A full analysis, published 2006, is contained in the House of Commons Science and Technology Committee Report 578i, and the Government reply 1036.*

The key advantages of commencing CCS full-scale pilot projects are to gain experience using the 8GW of plant which needs to be built in the UK before 2015 to replace LCPD coal opt-out. <u>This can create an option for full-scale CCS deployment, and deep cuts in CO_2 emissions from 2015</u>, when a further 20-30GW of coal plant needs to be replaced. This alternative can be considered a valuable option in the context of a portfolio of CO_2 reducing technologies.

Full-scale projects of CO_2 injection exist offshore in Norway at Sleipner and at Snøhvit, using CO_2 associated with hydrocarbon production, rather than CO_2 capture pre- or post-combustion. The CASTOR project in Denmark is gaining experience in reducing the cost of post-combustion CO_2 capture, at industrial scale, from coal combustion.

Additional CO_2 capture and injection pilots exist around the world. This shows that the <u>risks of capture and subsurface injection are constrained</u> adequately enough to enable large companies to propose full-scale operations.

Several propositions have emerged around the North Sea during 2005 and 2006, in mid-Norway (Tjeldbjergodden – Shell, Draugen & Heidrun oilfields), and in the UK (Peterhead-BP, Miller oilfield; Lincolnshire-E.ON; Tilbury-RWE; Tees-side -Progressive Energy). This shows that, even within the UK there are sufficient diversity of opportunities that <u>different CCS technologies are appropriate for different niches including retrofit applications, advanced coal combustion (gasification combined cycle or oxy-firing), or natural gas.</u>

There is no obvious winner now. Even in 10 or 20 years, existing assessments suggest that multiple CCS technologies will co-exist. Therefore several full-scale integrated demonstrator pilot projects would be appropriate now, to gain experience in the diversity of technologies applicable to the UK, eg coal retrofit, pre-combustion capture on gas, post-combustion capture on supercritical coal, post-combustion on gas, and coal IGCC.

In terms of the Treasury Questions:

Potential carbon reductions

CCS can reduce CO_2 emissions from fossil fuel power stations by 85 -90%. There is an efficiency penalty with the capture process, currently about 23%. This can be ameliorated by building new coal plant, which will improve from current UK plant efficiency of 32% to new supercritical coal plant efficiency of 46%, ie overall 35% with CCS.

If co-firing of 5-20% biomass occurs with coal, and CO_2 is captured from that biomass, then the system becomes carbon-neutral in the power station context. We are not aware of any full-life-cycle evaluations which include the growing, harvesting and transport of biomass and the transport and storage of CO_2. Estimates have been made by applying known evaluations for standard coal-fired and for biomass generation.

These imply that CCS fitted on conventional supercritical coal plant will have an overall emission of 50 - 90 gCO_2/kWh electricity (compared to 950 g CO_2/kWh without CCS); gas would be about 400 gCO_2/kWh without CCS. Comparable full-life-cycle evaluations, using the same analytical system, for wind are 25 $gCO_2$2/kWh, photovoltaic 110 gCO_2/kWh, and nuclear 30 -120 gCO_2/kWh (depending on ore grade, and excludes waste storage). For the UK, if 30GW of coal and gas fuelled plant needs to be replaced from 2015, the CCS option can reduce CO_2 emissions by 120 Mt/yr (out of 580 Mt/yr for all UK).

Technology

The conventional options available are 1) post-combustion capture (well proven, and working in Dakota-Weyburn and numerous oilfields – eg In Salah onshore Algeria), 2) pre-combustion conversion of gas or coal to H_2, and separation of CO_2 (long-established in oil refineries and town gas generation), 3) oxyfuel or IGCC (large experimental plants operating). Several analyses show all these options to be comparable in price. In the 10 - 20 year timescale, the IGCC is expected to improve most.

Engineering

The benefits of early adoption for the UK are to create an option to continue use of fossil fuels for electricity within the EU regulations, which has created the EU-ETS to increase the market price of carbon, and has the objective of near-to-zero fossil fuel generation to reduce CO_2 emissions as a key objective within FP7. Investing in CCS creates an option, at a known price for a power generator or oil company, to store CO_2 emissions, which can be viewed as 'insurance' against the anticipated price increases within the EU-ETS, as 'caps' become tighter. The UK has skills advantages compared to other nations – particularly in the ability to evaluate and use geological storage sites nationally. The gaps do not appear to be in skills, but in establishing business relationships between companies that have not previously interacted with each other. The risk is that the UK discovers the costs are greater than expected – so a funding system is needed which leaves an appropriate level of risk with industry.

Regulation

It is well understood that storage offshore is legal in association with Enhanced Oil Recovery. By contrast, storage in the larger volumes of saline aquifers requires legal assurance by changes to OSPAR and London Convention Annexes.

The DTI appears confident that the UK is leading negotiations, with the help of several international partners, and that these assurances can be delivered, possibly within 2 years. The existing UK legal framework for licensing, monitoring, and verifying, of offshore oil extraction can be adapted for the specifics of CO_2 storage – which uses geologically similar processes.

It is very clear that the Government has to take responsibility for storage sites when injection has finished. If the initial licensing is robust and comprehensive, then, as with abandoned oilfields, few problems should occur. Onshore regulation needs clarification, as there is potential for lower cost, locally based, CCS as part of CHP energy schemes, to prevent carbon lock-in.

Cost

The costs presented in Table 1 of the Treasury consultation appear higher than anticipated by the power industries involved, which for CCS run to 3.0-3.5p/kWh for coal, up to 4.8p/kWh for high price gas. In particular the international Carbon Capture Project anticipates cost reductions of 50% of the total – predominantly by reducing the cost of capture which comprises two thirds of the total.

The use of EOR as an adjunct to CCS could provide the UK with 5- 15% extra oil production from existing fields. Estimates by DTI and by the Norwegian Petroleum Directorate both suggest an additional 1,500M barrels recoverable on each side of the North Sea. This can act as a lifetime extension for North Sea skills, and assist security and diversity of supply for the UK. EOR is used after secondary water drive of oil production, so is entirely appropriate at this stage of the North Sea. However EOR has not been undertaken offshore on this scale.

Problems may include longer response times because of wider borehole spacing, and high maintenance costs for production platforms. An aspect of EOR not appreciated is that a different engineering of injection, from the top down of an oilfield instead of laterally, could result in 90% of the total oil being produced (instead of the current 45%) – the whole North Sea income could be achieved again. The disadvantage is that this requires much longer timescales – of 30 - 60 years, instead of 15. EOR will never be the cheapest oil internationally, compared to cheap production from Middle East. It is also worth noting that North Sea oil has never been the cheapest oil to produce, but this has not prevented creation of a value chain for its exploitation. The main use of EOR to a company involved in CCS, is to circumvent the OSPAR and London Convention legal requirements.

But if the UK ignores EOR, then the opportunity will disappear and the remaining oil will be stranded when infrastructure is removed. If saline aquifer storage of CO_2 becomes legal, then that will be much cheaper to inject than EOR, as a large complex offshore platform need not be maintained. Thus EOR is more valuable to the UK than to a company.

The BP proposition at Miller-Peterhead provides an instructive example. The advantage of this project is to demonstrate and learn technology. It is expensive because it is first of a kind, because it uses EOR with an expensive platform, and <u>because the capacity of the pipeline and platform are greatly under-utilised by a factor of 10</u>. *Expenditure*, simplistically, is $600M for generation and storage equipment, at 10% interest over 20 years; plus 20 years of operating an offshore platform typically at $110M/yr = $3,400M. *Income* from EOR is 40M barrels at $50 projected price = $2,000M. However this oil is taxed at 70%, leaving the company with only $600M. The $2,800M shortfall has to be covered by a price for CO_2, which has to be a minimum of 1.3Mt/yr x 20yr = 26Mt, implying a price of $ 108 /ton CO_2 (£58), which is significantly above the highest EU-ETS price of €30/ton CO_2.

BP stands to make an uncertain profit, and much less than a comparable investment in conventional oil exploration – and that risks shareholder disapproval. If the costs were shared by sending ten times more CO_2 through the pipeline, at full capacity, then the price required becomes much less (potentially as low as $11 /ton CO_2). In geological terms, the Miller area is part of a much larger complex of 10 oilfields, all of which are rich in natural CO_2 and can be considered as candidates for EOR.

Using Miller as a pilot could then unlock tax income for the Treasury of $1,400M from Miller over 20 years, and perhaps 5 times that from adjacent oilfields. If EOR is not undertaken as a by-product of CCS, then this income will never exist. In summary, if the consumer pays the cost of CO_2, the Treasury receives a type of stealth tax from the EOR, the UK gains in employment, and in diversity and security of supply.

Policy Incentives

If the UK provides no incentives then CCS will not occur until the EU-ETS price of CO_2 rises to a stable €30/ton CO_2 or more – and even then industry will have to gamble on a long term price minimum, and undertake pilots, before building cheaper routine technology.

This is unlikely to occur before end 2015, so that the UK will be committed to CO_2 emissions from fossil power stations built to maintain electricity supply in the "gap" period before new nuclear can be guaranteed to be available, and after then the UK will be forced to greatly increase (not just maintain) its nuclear electricity percentage, to meet CO_2 emission reductions.

If nuclear remains a Government favoured option, then investment could well be deterred in CCS and renewables, to wait for the electricity baseload to be met by the Government 'favoured' technology. Nuclear costs (of £70B decommissioning) will also either have to be met by increases on electricity bills (estimated at 25% increase during a 20 year decommissioning period), or be met from general taxation.

A financial method is needed which tunnels the CCS cost to the electricity consumer. This has been achieved by ROC with wind power, and the consumer is happy. The method must be able to apply to oil companies and to power generators, and to diverse types of low-carbon energy supply.

The ROC analogue is attractive, and could be applied to all low carbon energy. But it will be potentially difficult to ensure diversity if one single ROC is applied to onshore wind, offshore wind, CCS, nuclear. This is because the "wind experience" suggests that the lowest price near-to-market technology (onshore wind) becomes overwhelmingly favoured in a marketplace, to the exclusion of higher priced variants (eg offshore wind). Calculations show that the ROC equivalent for CCS would be about the same price as wind ROC (£50/MWh) initially. Then, as described in the BP-Miller example above, CCS technology improvement and optimised sharing of facilities would reduce costs so that the CCS ROC would need to be only half of the wind ROC. Public opinion has also persistently shown that CCS is favoured only if it is not perceived to remove funding from renewables.

A win-win strategy then becomes to operate multiple types of certificates, which can be adjusted independently, at no risk to the Treasury. For CCS these would apply only to the first full-scale pilot projects, which could also be designated as 'research' in terms of EU rules. ROC funding for renewables can continue as now (or grow). After the first phase of full-scale integrated CCS pilot projects, then substantial 'learning by doing' will have been gained. The ROC (or other) regime can be modified if necessary (as was done with UK-ETS).

When the EU-ETS reaches a stable high price then this enables funding of all technologies for CO_2 avoidance, and no new UK ROC are required for technologies which have reached the levels of development to compete equally on price. As a potentially even better alternative, a similar destination could also be reached by means of yearly auctions of low carbon electricity supply, as proposed for Carbon Contracts by Dieter Helm. This has the key attribute that intervention can occur throughout a project life, so that there is continuing pressure on industry to optimise efficiency and share facilities to reduce capex and opex. This would only work well if all technology prices for low carbon electricity had converged.

Conclusion

To create an option to use CCS as a fossil fuel CO_2 mitigation measure, it is necessary to act now to encourage several UK full-scale demonstrations. Then the UK is positioned by 2010 to 2012, to decide if it wishes to undertake routine building of CCS facilities to become operational before end 2015, when the LCPD reduces fossil fuel electricity generation, and existing generation plant starts retirals.

If no action is taken to enable CCS pilot projects, then nuclear fission and renewables are left as the only options for electricity. CCS combined with EOR can earn tax income for the Treasury, by enhancing long-term UK oil production. But this will only occur if CO_2 is given a value by means of ROC or low-carbon auctions, so that costs of low CO_2 electricity are met by consumers.