sustainable development commission

SDC discussion paper

Unlocking the power sector:
Proposal for long-term low-carbon electricity contracts

December 2006

Introduction

The Sustainable Development Commission (SDC) is concerned that current investment in the electricity generating sector (aside from investment in renewables mandated under the Renewables Obligation) is proceeding on a 'business as usual' trajectory, and is contrary to UK climate change policy. Of the 14GW of power plants awaiting consent, 60% of these are gas-fired CCGT, and are therefore carbon intensive. This trend will continue to lock the UK into high carbon electricity generation for the next 40 years, at exactly the time when we should be radically reducing carbon emissions. The cost to the UK of early retirement of this plant at some future date (i.e. before 2040), along with the carbon emissions accumulated in the interim, is likely to be more significant than the cost of supporting investments now in low carbon generating plant.

The SDC strongly supports Government moves to expand emissions trading schemes, and we remain committed to the EU Emissions Trading Scheme (EUETS), the largest such scheme in the world. However, we recognise that agreement on the design and allocation of allowances for Phase III of EUETS might not be reached until 2011. This is too late to provide a strong carbon price for long-term, capital-intensive investment decisions being made today.

We have therefore commissioned a short 'think-piece' on 'long-term low-carbon electricity contracts' by Paul Ekins and Nick Hughes at the Policy Studies Institute (PSI). We then convened a seminar to discuss this proposal with key UK Government officials and stakeholders from the business and NGO community, to discuss the paper in more detail. The key points from this seminar are summarised below. The PSI paper follows as an annex.

Our work in this area is intended to stimulate discussion about possible incentive mechanisms for ensuring sufficient quantities of new low carbon electricity generation over the next 10-20 years. It will also help to inform the SDC's advice to Government.

Long-term low-carbon electricity contracts

The proposal by Paul Ekins and Nick Hughes at the Policy Studies Institute is designed to help stimulate long-term investment in low carbon electricity generation up to 2030. This is in recognition of the special characteristics of this sector, such as the capital intensive nature of investments, long construction times, and the high cost of innovation, all of which act against investors opting for low carbon generating capacity, particularly when confronted by an uncertain carbon price going forward.

The key points from this work are summarised below:

- There is unlikely to be an agreement on the design and allocation of allowances under Phase III of EUETS until 2011
- In the absence of a serious, credible price for carbon post-2012, it is highly likely that the power sector will default to the fuel of choice (currently gas-fired CCGT plant) for the majority of the new capacity required after taking account of mandated[1] renewables
- This would lock the UK into large volumes of carbon-intensive, gas-based electricity generating capacity for the next 40 or so years, just when radical reductions in carbon emissions are required
- As a result, 'business as usual' has serious climate change, energy security, and electricity reliability implications

[1] Mandated under the Renewables Obligation.

- Between 60-150TWh of additional low carbon electricity output (over and above mandated renewables) needed by 2020 if dependence on gas is to be limited to 30% of total output; 116-160TWh by 2030
- This could be ensured by issuing 'long-term low-carbon electricity contracts' (LLECs) through a Government-backed auction process
- Electricity generators would bid in to supply specified quantities of output to come online at a future date – the LLEC would guarantee a minimum price for output, thus allowing investment to be secured
- Definition of low carbon electricity generation technologies and a clarification of the policy and regulatory process for planning, consent and (in some cases) decommissioning would be required prior to bids being received
- The liability for any payments under LLECs to electricity generators would be passed to consumers through an intermediary agency (such as the Non-Fossil Purchasing Agency), possibly through a levy on electricity bills (this could be achieved through the Fossil Fuel Levy, which still exists but is currently set at 0%)
- On maturity, any difference between the LLEC price and the wholesale price for electricity (including the price of carbon at the time) would be met by the agency responsible for handling this liability (see above)
- There would be penalties for non-delivery of contracted output by the generator
- The maximum cost of delivering 160TWh of output through LLECs (base on cost data from the DTI Energy Review 2006) might be £2.43bn if the future carbon price was zero, but would reduce to £450m with a carbon price of €25/tonne – this compares very well against the cost of the Renewables Obligation
- The proposal has the advantage of eliminating the need for Government to second-guess the price of low carbon electricity generation – developers would provide this information through their bids
- The proposal would be additional to the Renewables Obligation, with participation in one scheme ruling out participation in the other
- It would be possible to design the LLEC auction to stimulate investment in high cost low carbon technologies, such as marine renewables – this could be done by reserving a small proportion of the LLEC auction for specified technologies

Seminar summary

The SDC held a seminar on 29th November 2006 to discuss the LLEC proposal. This brought together around 30 key stakeholders from UK Government departments, along with business and NGO representatives. The following substantive issues were raised during a wide-ranging discussion:

- **Compatibility with the EUETS:** concerns were raised over how LLECs would fit with the EUETS, and whether introducing an additional scheme would send the wrong signal on the UK's commitment to the EUETS. However, others felt that there was a strong need for some sort of additional measure if climate change policy goals are to be met, and that LLECs are not incompatible with EUETS but could help support it.
- **Markets:** it was noted that some work would need to be done to look at how LLECs would fit into the existing electricity market, particularly to ensure against the creation of perverse incentives
- **Heat and CHP:** concerns were raised over the focus on electricity, although it was noted that the scheme could be designed to incentivise high quality CHP, and possibly other technologies such as solar thermal. For CHP, it was noted that this proposal was similar to the 'Whitehead Proposal' that was studied in some depth by Defra prior to the Energy

Review. Also, work would be required to determine how the heat output from CHP should be treated, although EU-approved baselines now exist.

- Capacity vs. output: there were suggestions that LLECs could apply to capacity rather than output, as this might be simpler to incentivise. However, others expressed concerns over this approach, which would force the consideration of relative capacity factors, and would not necessarily result in low carbon generating plant being efficiently used.
- Impact on demand-side measures: some participants questioned the impact of LLECs on demand-side measures, which could potentially reduce overall demand for electricity and render new output unnecessary. However, others felt that the interaction of LLECs with other policy measures (such as the proposal for a cap on energy suppliers post-2012) might improve certainty over future levels of demand – and that regardless, investors have to deal with these issues on a regular basis. Also, it was noted that suppressed demand would most likely lead to the early closure of older plant, which would help to reduce carbon emissions.

Conclusion

The SDC intends to use this work to help inform our advice to Government as we continue to develop our climate change and energy policy work programme. We believe that it is crucial to the success of UK climate change policy to ensure that all possible steps are taken now to ***prevent unnecessary lock-in to carbon intensive pathways***, whether this is in electricity generation, housing, transport, or any other sector.

There is strong evidence to suggest that the lack of uncertainty over EUETS in Phase III, along with the inherent characteristics of the electricity generating sector, means that future investment in power capacity outside that mandated by the Renewables Obligation, will go to carbon intensive plant – mainly gas-fired CCGT. This will lock the UK into a carbon intensive electricity mix at exactly the point when we should be radically reducing carbon emissions. Furthermore, we will fail to take advantage of the huge investments that will be required by the electricity sector over the next 10-20 years as the network infrastructure is renewed and old generating plants are retired.

The SDC will continue to push for an expansion of emissions trading schemes and for policies to reduce energy demand. However, we believe that additional measures to prevent unnecessary lock-in in the power sector demand urgent attention, and we recommend this proposal as one that deserves further consideration.

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Policy Studies Institute

LONG-TERM LOW-CARBON ELECTRICITY CONTRACTS FOR THE UK

A paper for the Sustainable Development Commission
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LONG-TERM LOW-CARBON ELECTRICITY CONTRACTS FOR THE UK

1. BACKGROUND AND PURPOSE OF THIS PAPER

Major issues facing European energy policy now include:

- Volatile and potentially high oil and gas prices
- Energy security, meaning the need to be able to import the fuels required by the UK
- Energy reliability, meaning having the necessary plant and infrastructure to produce and deliver energy in the required form to consumers, when and where they want it
- Climate change, requiring the progressive decarbonisation of UK energy use

The Sustainable Development Commission (SDC) has said that it is interested in the potential of incentive mechanisms for low carbon investment, particularly in the electricity sector, to help provide the long-term investment framework that is currently lacking with the EU Emissions Trading Scheme (EUETS). This paper comprises a concise 'think-piece' on the subject of **long-term low-carbon electricity contracts**, which will be the basis for a stakeholder seminar to discuss the idea in more detail.

2. RATIONALE FOR THE PAPER

Action to reduce carbon emissions requires a long-term economic framework to provide an incentive for low carbon innovation and investment, and behavioural change. The SDC believes that economy-wide emissions trading, based on scientifically credible absolute cuts in carbon emissions, should be the policy framework within which climate change mitigation takes place.

The EUETS is currently the most developed carbon emissions trading scheme in the world, and is responsible for delivering the majority of the emission reductions expected from the power and large industrial sectors. However, emissions caps in Phase II (2008-2011) remain too weak to deliver a strong carbon price with which to influence investment decisions, and a final decision on the design and allocation of allowances for Phase III of the EUETS (2012 onwards) is not expected until around 2011, a year before it is due to come into force.

This presents serious concerns for climate change policy generally, but for energy policy specifically; investment horizons in the electricity sector are long and capital investments are bulky. In the absence of a serious, credible price for carbon post-2012, it is highly likely that the power sector will default to the fuel of choice for the majority of the new capacity required after mandated renewables are accounted for. This fuel will be gas or coal, and the implications for the UK in terms of both carbon emissions and energy security are potentially serious. Further gas-based electricity capacity without carbon capture and storage will lock the UK into a carbon-intensive electricity sector for decades to come at exactly the point when the Government is committed to the UK making radical cuts in emissions. This would be even truer for further coal-based generation. There are also serious energy security concerns about high levels of gas-fired generation (currently around 40%), as the UK becomes more dependent on imports and competition for gas supplies becomes more pronounced in the future.

3. THE NEED AND OPTIONS FOR SECURE, LOW-CARBON ELECTRICITY GENERATION

Avoidance of excessive dependence on gas

There is some debate as to the extent to which markets will, without extra incentives, provide energy security and reliability in relation to both gas and electricity, with concerns about the former deriving from the concentration of available gas supplies in a few regions of the world, and about the latter from the need to replace a significant proportion of the UK's generating plant over the next two decades. Moreover, the replacement of retiring nuclear plant with fossil fuel generation, as seems likely under current market conditions, would, as noted above, significantly increase carbon emissions from power generation, as well as giving rise to further worries about energy security.

Table 3.1 presents the Department of Trade and Industry's projections of the electricity generation fuel mix through to 2020.

Electricity generation fuel mix (TWh)							
Central favourable to gas	**1990**	**1995**	**2000**	**2005**	**2010**	**2015**	**2020**
Coal	204	145	112	126	106	100	82
Oil	15	9	2	2	2	2	1
Gas	0	57	127	135	137	183	235
Nuclear	59	81	78	75	73	34	26
Renewables	5	6	10	17	33	53	53
Imports	12	16	14	11	11	11	11
Pumped storage	2	2	3	3	3	3	3
Total	**298**	**315**	**346**	**369**	**365**	**386**	**411**
Central favourable to coal	**1990**	**1995**	**2000**	**2005**	**2010**	**2015**	**2020**
Coal	204	145	112	126	119	116	94
Oil	15	9	2	2	3	2	2
Gas	0	57	127	135	122	164	219
Nuclear	59	81	78	75	73	34	26
Renewables	5	6	10	17	33	53	53
Imports	12	16	14	11	11	11	11
Pumped storage	2	2	3	3	3	3	3
Total	**298**	**315**	**346**	**369**	**362**	**383**	**407**

Table 3.1: Electricity Generation Fuel Mix
Source: DTI 2006, Table C3, p.203

Table 3.2 presents the latest projections for electricity generation from Cambridge Econometrics (CE 2006, p.4-10), including CHP and industrial and commercial generation (Table 3.1 from the DTI only includes major power producers plus renewables generators). Three extra rows have been added, which give the additional low-carbon generation that would be required if the use of natural gas in CHP and CCGTs were to be restricted (on the grounds of security of supply) to 40%, 35% and 30% of generation. It should be noted that the table's projections for renewables (RES in Table 3.2) assume that the Government's new target in the Renewables Obligation for renewables to provide 20% of generation by 2020 is met. The scope for renewables to supply much more than 20% of generation in this timescale is doubtful, though they could expand further thereafter. The column for 2030 assumes that both total and gas-fired generation grow at the same rate as 2010-20.

PLANT	1990[1]	2000	2010	2015	2020	2030
Capacity (GW)						
Coal (not FGD)		18.9	8.4	6.0	0.5	
Coal (FGD)		6.0	10.4	10.5	10.9	
CCGT (not CHP)		19.3	26.8	28.1	30.5	
Nuclear		12.5	8.7	4.6	2.4	
CHP (not RES)		4.6	9.2	10.6	12.9	
RES (inc. CHP)		2.4	7.0	11.5	14.3	
Other (oil, mixed)		14.8	10.8	8.3	5.0	
Net imports		2.0	4.6	4.6	4.6	
TOTAL		**80.4**	**85.8**	**84.2**	**81.0**	
Generation (TWh)						
Coal (not FGD)	204	67.3	13.6	8.9	0.0	
Coal (FGD)		34.2	11.5	17.0	21.7	
CCGT (not CHP)	0	117.4	185.7	205.0	205.5	227.5
Nuclear	59	85.1	64.1	28.0	9.9	
CHP (not RES)	na	26.1	49.6	65.7	81.5	81.5
RES (inc. CHP)	5	10.3	46.1	71.6	92.9	
Other (oil, mixed)	17	36.6	21.3	15.2	10.0	
Net imports	12	14.3	29.6	29.6	29.6	
TOTAL	**298**	**391.4**	**421.5**	**441.1**	**450.9**	**482.5**
Gas max.40%[2] CE DTI[3]			 66.7 0	 94.3 19.7	 106.6 63.4	 116
Gas max.35% CE DTI			 87.8 2.3	 116.3 38.9	 129.2 83.9	 140.1
Gas max.30% CE DTI			 108.9 20.5	 132.3 58.2	 151.7 104.3	 164.3

[1] From Table 3.1, for comparison. The difference between the CE and DTI total generation figures is that the CE figures include industrial and commercial generators (CHP and autogenerators), whereas the DTI figures only include the major power producers, plus renewable generators.
[2] Calculation: (CCGT+CHP (not RES)) – Total*0.4
[3] This and DTI rows below calculated from Table 3.1.
Source: CE 2006, p.4-10

Table 3.2 shows that, if it is desired to keep gas at a maximum of 40% of generation by major power producers (the DTI figures), then an extra 19.7 TWh of non-gas generation is required by 2015, rising to 63.4 TWh by 2020. This rises to 58.2 TWh and 104.3 TWh respectively if the desired maximum proportion is only 30%. If it is desired to keep total gas generation (the CE figures) to 40% of total generation, then the 2015, 2020 and 2030 figures are 94.3, 106.6 and 116 TWh respectively, rising to 132.3, 151.7 and 164.3 TWh for a 30% maximum limit.

There are obviously major uncertainties in connection with all these projections (plant life times may be extended, efficiency programmes may be more effective etc.), but this table gives a first estimate that the likely need for low-carbon generation by 2020 could be 60-150 TWh by 2020, and 116-160 TWh by 2030, if undue dependence on natural gas is to be avoided (the range depending on how ‘undue dependence’ is defined and, in the former case, also on which generation is included).

Possible options for low-carbon generation

One option for reducing the gas in power generation is to increase the use of coal, about which security of supply concerns are far less salient. However, coal is more carbon-intensive than gas, and there is a continuing need to reduce carbon emissions from power generation if the Government is to meet its target of putting the UK on a trajectory to achieve a 60% reduction in carbon emissions (from 1990’s level) by 2050. It is therefore necessary that the extra generation identified in Table 3.1 comes from low-carbon sources.

In an economy largely based on fossil fuels, all sources of power generation entail some carbon emissions over their lifetime (for example, from the manufacture of the necessary generation equipment). Table 3.3 identifies the lifetime carbon emissions that have been calculated for different sources.

Total Lifetime Releases From Selected Technologies	
Technology	**GC / kWh***
Lignite	228
Coal	206
Natural	105
Biomass	8-17
Wind	3-10
Nuclear	3-6

* Grams of Carbon per kilowatt hour of electricity produced

Table 3.3: Total Lifetime Releases from Selected Technologies
Source: DTI 2006, Table 5.3, p.116

Table 3.3 shows that there is an order of magnitude difference between the lifetime emissions of nuclear and selected renewables and of fossil fuel generation. Table 3.3 does not give carbon emissions from fossil fuel plant fitted with carbon capture and storage (CCS), but this can be roughly calculated on the basis that CCS “might reduce the carbon emissions from the combustion of fossil fuels … by 80-90% relative to the same plant without CCS” (DTI 2006, p.108). On the basis of the figures above, this would reduce the lifetime emissions of a natural gas plant from 105 to 11-21 GC/KWh, only slightly more than from biomass[1]. Emissions from a CCS coal plant, calculated on the same basis, are likely to be 23-46 GC/KWh. For the purposes of this paper, therefore, 'low-carbon generation' is defined as any source of electricity with less than 50 GC/KWh of generation (which might also include any heat generated through CHP) over its projected lifetime. This would rule out conventional fossil fuel stations, but allow the other technologies in Table 3.3, and CCS. It is not clear from Table 3.3 whether (non-CCS) gas-fired CHP would qualify as low-carbon under this definition. Clearly it would not qualify unless its component of heat use was included in the category of 'generation'. A decision would need to be taken as to whether its benefits of added efficiency overcame its disadvantages of increasing dependence on natural gas.

Clearly this definition is to some extent arbitrary, and the numbers are still uncertain. For example, Spath & Mann (2004, p.iii) give the lifecycle emissions from a coal plant with sequestration as 67 GC/kWh, and were a new electricity source to be developed with lifetime emissions in excess of 50 GC/kWh, but still well below those of conventional fossil fuel plant, the definition could be adjusted to include it. For the present, however, the definition serves the purpose of this paper in identifying the available low-carbon technologies (inc. high-efficiency gas-CHP) that could be fitted on an extensive scale. For the purposes of this discussion, these technologies can be grouped into a number of different categories:

1. Nuclear (large, centralised plant)
2. Fossil-fuel with CCS (large, centralised plant)
3. Large-scale renewables (large, centralised plant, e.g. offshore wind, wave)
4. Large-scale industrial gas-fired CHP (large, centralised plant)
5. Medium-scale gas-fired CHP (distributed generation)
6. Medium-scale biomass CHP (distributed generation)
7. Small-scale renewables (distributed generation, e.g. small, onshore wind)
8. Household-scale renewables (and perhaps CHP) (microgeneration)

This list is not meant to be definitive, and of course other technologies may be developed, but it shows that there already exists a range of low-carbon generation options, many of which could be implemented to produce a significant quantity of electricity (plus some heat with CHP).

4. POLICIES FOR LOW-CARBON GENERATION

This section discusses various mechanisms or policy instruments which might interact, or interfere, with the proposal for long-term electricity contracts which is to be presented, or from which lessons could be learned.

With respect to the decarbonisation of electricity supply, the major current policies are the Renewables Obligation (RO) and the EU Emissions Trading Scheme (ETS).

Renewables Obligation

[1] This is an underestimate because the lifetime emissions from natural gas include those from constructing the plant, which will not be reduced by CCS, and the CCS infrastructure (capture, transport, disposal) will have some emissions associated with its construction, which is also not included. However, the extent of the underestimate is likely to be relatively small.

The 2006 Energy Review announced reforms to the RO in response to concerns that it was turning out to be quite expensive, with the cheapest renewable technologies receiving above-normal profits, that more expensive technologies were not being adequately incentivised to be deployed, and that the buy-out fund provides an incentive to maintain a gap between the percentage obligation and the renewable power actually generated (Shell 2005). The reforms to the RO which the Energy Review either announced or which the Government will consult on are:

1. Increase of the RO to 20% of generation by 2020.
2. Amendment of RO to reduce the risk of over-supply of renewables (up to 20%).
3. Adapting the RO (perhaps introducing banding) to give support to less established technologies.

EU ETS

The EU ETS has been successfully established, although it seems that the free allocation of emission permits to participating sectors has resulted in windfall profits to sectors like power generation, which are able to raise their prices to consumers to reflect their opportunity cost of generation, and differences in the National Allocation Plans may have led to market distortions between EU Member States. However, the major cause for concern, as noted above, is that the current end of the timescale of Phase 2 (2012) is very soon in terms of the investments in low-carbon technologies that need to be made, and there is very little assurance of the price of carbon beyond that date. This price depends not only on the details of Phase 3 of EU ETS but on international developments, e.g. in relation to the post-Kyoto situation, which are even more uncertain. There is very little that the UK Government can do about these broader uncertainties, which cannot but discourage low-carbon investment in the UK.

UK Emissions Trading Scheme (UK ETS)

The UK ETS was launched in 2002. The Government made £215m available, and invited organisations to bid in carbon reductions for a certain price. 33 organisations now participate in the scheme, and have commitments to reduce their emissions by nearly 12m tonnes of CO2-equivalent over the lifetime of the scheme (2002-06)[2]. One of the difficulties in setting up the scheme was the agreement of the baseline against which the emissions reductions would be calculated.

Energy Performance Commitment

A further proposal in the 2006 Energy Review, which will be consulted on, was that there should be some kind of UK emissions trading scheme for large commercial and public sector organisations, which are not included in the EU ETS or Climate Change Agreements (CCAs). This could reduce emissions from this sector, but would do little to incentivise low-carbon power generation, unless the organisations were allowed to reduce their emissions by explicitly purchasing renewable or low-carbon electricity. This issue is discussed further below.

[2] See http://www.defra.gov.uk/Environment/climatechange/trading/uk/index.htm

Non-Fossil Fuel Obligation (NFFO)

The NFFO was a policy introduced in the 1990s to encourage non-fossil generation. It worked by inviting prospective generators to bid for non-fossil generation contracts for certain specified technologies (which changed over the five NFFO rounds in the years up to 1998, the date of the last round). While it succeeded in attracting bids, relatively few of these were converted into actual projects that generated power successfully. In fact, as at June 2005 less than half the contracted projects, comprising less than one third of the contracted capacity[3], were actually delivered. The main reasons for this seem to have been:

- There was intense price pressure on the bids. At the same time the process of submitting bids was not onerous, and there was no penalty for failing to deliver on contracts. This led to ambitious bids which on further analysis subsequent to the award of a contract proved to be unviable.
- The bids were made prior to obtaining planning permission for the project. This subsequently proved in some cases to be more difficult to obtain than anticipated.
- Bids that could not go ahead were not transferable to other sites or other developers who might have taken them forward.

5. LONG-TERM LOW-CARBON ELECTRICITY CONTRACTS

It can be seen from Table 3.2 that, even with 20% generation from centralised renewables by 2020, there is a risk that, without substantial further low-carbon generation, UK power supply will become excessively dependent on natural gas. It could also become excessively carbon-intensive (if the alternative to natural gas is coal without CCS, and even non-CHP gas has significant carbon emissions).

One response to such concerns, and to the long-term uncertainties related to the EU ETS, has been the proposal of long-term carbon contracts (Helm and Hepburn, 2005; Ofgem 2006, pp.26-27, 80-82). The major difference between the long-term electricity contracts that are proposed here and long-term carbon contracts is that the contract being entered into is for low-carbon electricity rather than for carbon reductions. One advantage of this is that it is a contract for a delivered good, rather than an avoided effect, which removes the need to consider baseline carbon emissions (which is necessary to calculate reductions, or the emissions that have been avoided). Another advantage is that it avoids further complexity in the carbon market, and removes the risk that carbon reductions may be delivered abroad (through one of various carbon trading mechanisms) rather than low-carbon generation (which is what is required) being delivered in the UK. What this proposal is intended to ensure is that low-carbon generation comes on stream at the time it is needed.

The basic proposal being put forward here is that the Government announces that it will issue fixed-price contracts (long-term low-carbon electricity contracts, LLECs) guaranteeing the price of tranches of low-carbon generation to come on stream on an annual basis from, say, 2016, over a period, perhaps up to 2030. As noted in Table 3.2 this might involve about 160 TWh, about 30% of UK generation, by 2030. It is

[3] See http://www.dti.gov.uk/files/file22449.pdf#search=%22NFFO%22

suggested that 'low-carbon' is defined as having lifetime emissions of below 50 GC/KWh, as discussed above.

The Government would ask for bids of prices (per MWh) at which generators would contract to supply a specified quantity of low-carbon power generation, and the period over which they would require those prices to be paid. The Government would accept the bids, and guarantee the prices, up to the level of low-carbon generation which it wished to incentivise. This quantity should be at least sufficient to reduce gas generation to the desired proportion, but it could be more than this if it was desired to make a further contribution to the 60% carbon reduction target by 2050. The quantity contracted would have to increase annually. The period of ten years or more (up to 2030) is important because the per MWh price of a technology may depend heavily on whether it is able to rely on economies of scale.

For LLEC bids to be made, the Government would need to carry out a programme of work to ensure that the major generic potential sources of low-carbon generation set out in Section 3 (nuclear, CCS, large-scale renewables, small-scale renewables, CHP and microgeneration) would be able to make informed bids. For nuclear, this would mean clarification of licensing and planning requirements, and the liabilities of decommissioning, nuclear waste disposal and accident insurance; for CCS this would mean clarification of issues of security of storage; for large-scale renewables this would mean clarification of the requirements for new transmission and for reserve generation to take account of intermittency, and, perhaps, obtaining planning permission prior to the bid; for distributed generation (including CHP and small-scale renewables) this would mean further clarification of the terms of connection into the distribution system (and carbon payments also to be paid for renewable heat as part of CHP); while microgeneration would need a whole range of clarifications from planning law to safety, as well as details of connection into the power distribution system and the nature of that system (and associated costs of achieving it) if it was to accommodate a great increase in microgeneration. It should be noted that a number of these issues were raised in the Energy Review (DTI 2006) and are now being followed up.

6. IMPLEMENTATION ISSUES

6.1 Lessons from Past Policy Initiatives

NFFO

NFFO provides a number of important lessons in respect of LLECs. First, it seems to be counterproductive to bear down too heavily on prices. This can result in unrealistic bids which cannot be delivered. Second, there would appear to need to be some kind of penalty mechanism in the event of non-delivery on contracts. Third, the public policy framework (including planning issues) would need to be transparent and the outcomes secure if firm bids, with penalties for non-delivery, were to be forthcoming.

Another NFFO lesson is the financing mechanism, the Fossil Fuel Levy (FFL). This was a percentage charge added to consumers' electricity bills. The FFL mechanism still exists, although it is currently set at zero. It could be reintroduced without the need for primary legislation (perhaps as a rising tariff, in order to reduce regressive effects) to finance LLECs.

UK ETS
The main lesson from the UKETS was the difficulty in specifying baselines against which the carbon reductions would be calculated. This is one of the main arguments against carbon contracts, but it does not apply to LLECs. The UK ETS is due to finish in 2006, so there are no issues of potential interaction between the policies.

6.2 Interactions with Present and Proposed Policy Initiatives

Renewables Obligation (RO)
There is unlikely to be much scope for renewables before 2020 beyond the 20% now envisaged by the RO. However, interactions with LLECs could be simplified by making the schemes mutually exclusive. Prospective renewables generators could bid for LLECs on the understanding that, if granted, they would not be eligible for Renewables Obligation Certificates (ROCs), and the prices at which they bid in would need to take this into account.

There will be consultation on how the RO can be banded for different technologies. This would not be necessary for LLECs, because generators can bid for LLECs with any low-carbon technology and specify a price which they think would be profitable. There would be no obligation on government to accept the lowest price bids, so it could choose any technology, at a given price, which it thought promising. In fact, LLECs might be a preferable way of bringing on emerging technologies to bands under the RO. With such bands, the Government will have to second guess the prices of the technologies, in order to gauge the level of support each band will require (as noted above, this was also one of the problems with NFFO, when Government drove the price down so hard that unrealistic bids were the result). With LLECs prospective generators can bid in realistic prices, which Government can then choose to accept or not (to stress again, there is therefore no presumption that with LLECs Government would be committed to choosing the least costly low-carbon option – it could choose to give LLECs on a range of criteria, including a desire to bring on emerging technologies).

EU ETS and the price of carbon
The coverage of EU ETS is currently large combustion installations, including those in the power generation sector. Phase 2 runs until 2012. Nothing has been decided about Phase 3, beyond the fact that there will be a Phase 3. It may be that by the time of Phase 3 the EU ETS contains both aviation and road transport.

For generation that emits no carbon (nuclear, renewables, CCS etc.) the only interaction between the EU ETS and LLECs will be through the price of carbon, as shown in Figure 6.1, in which P_C is the price of carbon, P_{F+C} is the price of fossil fuel generation, including the price of carbon (other things being equal this will be higher for coal-fired than gas-fired generation), P_F is the price of fossil fuel generation when P_C is zero, and P_L is the price of LLECs. The gap between P_L and P_{F+C} is the extent of the subsidy to low-carbon generation.

P_C is very uncertain and in the absence of international agreement post-2012 on carbon reduction targets may be zero or close to zero. This would obviously maximise the subsidy required by low-carbon generation. On the other hand, if P_C was high then

P_L might turn out to be below P_{F+C} (as with the case of nuclear in Table 6.1 below) in which case no subsidy for low-carbon generation would be required.

An advantage of the LLEC proposal is that its operation is unaffected by the uncertainties surrounding the price of carbon. Generators would make their bids according to the cost of low-carbon generation. The carbon price at the time of generation would affect the subsidy required, but not the bid. In accepting the bid, and having a view about the cost of fossil generation at the time the generation would be delivered, the Government would know the maximum potential subsidy (with P_C equalling zero), but this could be reduced with policies that increased P_C. The implications of this for the funding mechanism are discussed further below.

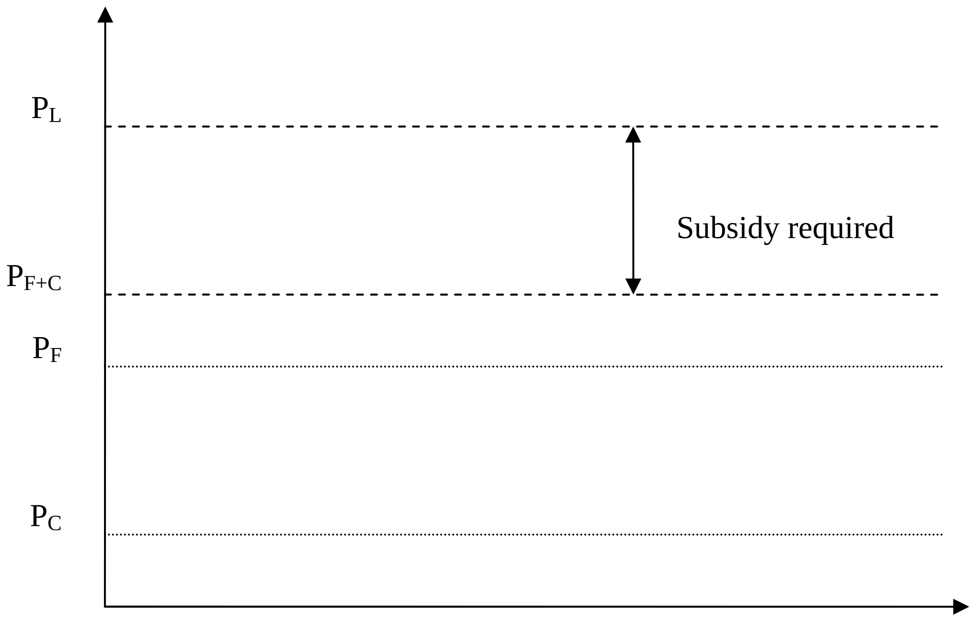

Figure 6.1: Interaction between the price of LLECs and of conventional generation

Energy Performance Commitment (EPC)
Assuming that the EPC will be denominated in carbon, then this will need to include the average carbon factor of the electricity, which will change depending on the number of LLECs. It also could be part of the design that organisations could meet part of the EPC by buying ROCs or the output of LLECs directly.

6.3 Other Implementation Issues

Awarding Contracts
The contracts could be awarded on the basis of auctions, very much as under NFFO, except that Government would not specify a price range or technology bands. Any low-carbon technology could be bid into the auctions, which could take place annually. The bid would specify the quantity of low-carbon generation to be delivered at a certain price by a certain date over a certain period using a certain technology.
Penalties for Non-Delivery

In order to ensure realistic bids, there would need to be penalties for non-delivery. However, it would obviously only be equitable for these penalties to be due when the failure to deliver was due to factors in principle under the developer's control. For example, failure to gain planning permission for a project should not result in penalties. This emphasises the importance of the Government clarifying the policy and planning framework for low-carbon generation to the greatest possible extent. The consultation on nuclear power and planning in the Energy Review (DTI 2006, Annex A, pp.161-181) gives some idea as to how the Government is now seeking to do this. The Statement of Need envisaged there need not only apply to nuclear power. It could apply to all low-carbon generation technologies, with the presumption that appropriately sited (according to the strategic siting assessment, also proposed in Annex A but also potentially applicable beyond nuclear power), such technologies would be given planning permission. That should ensure that failure to deliver on LLECs was not due to policy/planning failure.

As to the size of the penalty, this is a relative detail. It needs to be large enough to constitute a significant incentive to deliver on time, but not so large as to deter a bid in the first place. There is always some commercial risk in such bids. Penalising the downside too heavily could deter potentially viable bids from coming forward in the first place.

Prices and Liabilities
The Energy Review gives some indicative prices for different generation technologies, which are used in this paper for purely illustrative purposes as to the possible cost of LLECs. The ranges (rough, because they have been read off a graph in the Energy Review rather than coming from the underlying database) are shown in Table 6.1.

Generating Technology	Cost range, £/MWh, CP=0	Cost range, £/MWh, CP=€25	Liability wrt cheapest alternative, £/MWh		LLEC Liability (£m) of illustrative 150TWh mix, middle of cost range		
			CP=0	CP=€25	TWh	CP=0	CP=€25
New nuclear	30-44	30-44	3-17	(-10)-4	80	800	(-240)
Retrofit PF coal, with FGD and CCS	36-45	36-48	9-18	(-4)-8	30	405	60
New PF coal, with FGD and CCS	41-49	41-52	14-22	1-12	20	360	130
IGCC with CCS	45-51	45-53	18-24	5-13	20	420	180
Onshore wind	51-63	51-63	24-36	11-23	0	0	0
Offshore wind	55-89	55-89	28-62	15-49	10	450	320
CCGT	35	43	8	3	Na		
IGCC	29-31	43-45	2-4	3-5	Na		
PF coal with FGD	27	40	0	0	Na		
TOTAL					**160**	**2435**	**450**

Table 6.1: Cost Ranges and Potential Liability of Different LLECs, with different carbon prices (CP is carbon price, per tonne CO_2)
Source of cost data: DTI 2006, Charts B1, B2, pp.185-6

Table 6.1 shows that, on the DTI's figures, pulverised coal fuel (PF) with flue gas desulphurisation (FGD) is the cheapest generating technology (clearly this depends critically on assumptions about the relative price of coal and natural gas), at £27/MWh. With a carbon price of €25/tCO2 this rises to £40/MWh, and the difference between this and the other fossil fuel generating technologies (IGCC and CCGT) is then quite small.

New nuclear is the cheapest low-carbon generation technology in Table 6.1, with a cost range of £30-44/MWh. Most expensive is offshore wind, with a range of £55-89/MWh. Neither the nuclear nor wind prices are affected by the carbon price, because they are emission-free. The CCS technologies lie in between, and their prices are affected by the carbon price by £2-3/MWh, because CCS does not capture all emissions.

Taking the middle of these cost ranges, awarding LLECs for 160 TWh (the kind of amount that might be necessary by 2030, see Table 3.2) might cost around £2.4 billion per year if carbon was unpriced, but only £450 million per year if the price of carbon was €25/tCO2 (when nuclear power's mid-range cost is below that of the cheapest fossil alternative). This may be compared with a projected cost of around £1 billion per year by 2010 to support around 35 TWh p.a. of renewables generation through the Renewables Obligation. The mix of technologies shown for the 160 TWh assumes a new nuclear programme that by 2030 maintains nuclear generation at about the same level as in 2005 (80 TWh), a mix of CCS technologies, and 10 TWh of more expensive offshore wind (it is assumed that expansion of onshore wind and other renewables, and some offshore wind, is supported through the RO).

Clearly there is substantial uncertainty about all these cost numbers, because none of the technologies in the illustrative mix (assuming that the new nuclear is Generation III reactors) have actually been built in the UK, and the actual numbers and cost ranking of the technologies may turn out to be different from that shown. One of the advantages of the LLECs proposal is that it does not require the Government to second-guess electricity prices well into the future (one of the disadvantages of NFFO, as discussed above). Rather, would-be LLEC generators would bid into the scheme at the price which they thought viable according to their own calculations. However, uncertain though the numbers above are, the costs shown would have to be very significant underestimates for LLECs to turn out more expensive per MWh than the support given to renewables under the RO.

Where would the money come from?
Given the experience of NFFO and the RO, it seems most unlikely that funding for the LLECs would come from taxes. Rather it is likely that they would come either from a renewed Fossil Fuel Levy (FFL) or through an obligation on suppliers to purchase the power generated through LLECs. In both cases, the cost would fall on electricity consumers. If it was spread evenly over all consumers, then with an estimated generation in 2030 of 480 TWh (see Table 3.2), the maximum cost of the LLECs would be about 0.5p/kWh. It would be easy to calculate the cost of different illustrative mixes, with more or less of some technologies.

As Figure 6.1 and Table 6.1 both make clear, the subsidy required by LLECs will depend on both the basic cost of conventional fossil generation and the cost of carbon.

If the cost of LLECs was provided through the FFL, then generators would have to bid their generation into the wholesale electricity market (through NETA, the New Electricity Trading Arrangements, introduced in 2001) in the normal way. They would then be refunded from the FFL receipts the difference between the wholesale price they had received and the LLEC price they had bid.

If LLECs were the subject of a supplier obligation, there would still need to be an intermediary to pay LLEC generators the difference between the wholesale price of their power and their LLEC bids, and to average the cost of the LLEC subsidy over the different low-carbon technologies in order to calculate a single net LLEC price for the suppliers. The need for this (which differs from the operation of the RO because there is no buy-out price, which effectively fixes the price of the ROCs) means that funding LLECs through an FFL-type mechanism would probably be simpler than through an obligation. Once they had paid the average LLEC subsidy, suppliers would simply pass the extra cost on to their customers, as they currently do with the cost of ROCs.

Market and State Aid implications

The RO will already have reserved up to 20% of power generation for renewables by 2020. It might be thought that earmarking another 30% of generation for low-carbon generation through LLECs is undesirable in terms of maintaining the openness of the UK's liberalised electricity market.

However, if the market will not produce low-carbon electricity from diverse sources by itself, then there is actually little option, if these are important social objectives, but to constrain it to do so. LLECs have the advantage of allowing the market to come forward with proposals as to the actual technologies that would be used to satisfy the objectives.

The interaction of environmental protection with other European Community (EC) policies on state aid and market integration is a more complicated area, in which significant areas of uncertainty remain. This is in part due to a series of rulings by the European Court of Justice (ECJ) which according to some experts, have failed to clarify the precise conditions and circumstances under which principles of free trade and market integration can give way to priorities of environmental protection. For a detailed discussion of these cases and their implications, see Jacobs (2006).

In recent years the EEC Treaty has been amended to include environmental concerns amongst its guiding principles (Articles 2 and 6 EC). What has emerged from the recent case history described by Jacobs (2006) is that the ECJ has on several occasions viewed environmental protection as a goal of such importance that it has been prepared to move directly to citing such articles, even while circumscribing such usually fundamental principles as market discrimination and proportionality. Whilst Jacobs complains that this has created considerable uncertainty regarding how such principles should relate to environmental protection, one significant upshot is that the status of environmental principles in relation to those of free trade seems to be extremely high.

A key concern is whether LLECs would be classed as state aid. In *Preussen Elektra*, Article 87 EC, which offers a definition of state aid, was interpreted as meaning that for a measure to be classed as state aid it must involve the transfer of financial resources from the state to a beneficiary, whereas measures that involve the state affecting the market but at no financial cost to itself, would be outside of this definition (Jacobs 2000, 2006). If this interpretation holds, and given the expectation (above) that the costs of LLECs will be passed to the consumer, it is possible that LLECs may not be classed as state aid. However, a wider definition of state aid is possible within Article 87 EC, where 'any measure which confers economic advantages on specific undertakings, and which is the result of conduct attributable to the state' can constitute state aid (Jacobs 2000). Therefore state aid classification of LLECs remains a possibility. By comparison, the UK Renewables Obligation was classed as a state aid scheme by the EC specifically because of the role of the buy out fund in redistributing funds to holders of ROCs (EC 2006). In this example the involvement of the state in administering recycled money seems to have been enough to invoke state aid status.

If a long term electricity contract scheme was defined as state aid, it would nevertheless have a good prospect of being permitted on environmental grounds. The context provided by Articles 2 and 6 EC, and the more recent series of ECJ rulings described by Jacobs (2006) set a very favourable context for environmental measures. Moreover the Community Guidelines on State Aid for Environmental Protection (EC 2001) specifically state that 'where measures to promote renewable sources of energy and the combined production of electric power and heat constitute state aid, they are acceptable subject to certain conditions' [p.24]. Of these conditions the most prevalent is the concern that firms should not be overcompensated, which would remove the incentive to increase their competitiveness. The appropriate level of aid should 'cover the difference between the cost of producing energy from renewable sources and the market price of energy' [p.56]. Interestingly, a qualification that 'when studying cases, the Commission will take account of the competitive position of each form of energy involved' [p.56] appears to allow targeting of less mature technologies for increased support. However, it also seems clear that measures would have to be flexible enough to reduce the amount of aid given for a particular technology as it became more competitive in its own right, to avoid over compensation. An annual process of auctioning LLECs might meet this requirement, as presumably at each new auction generators would have an incentive to bid at as low a level as possible in order to increase their chances of success. However, the time lag between the agreement of the price and the delivering of the power might cause concerns if it was felt that during this period the technology could have increased its efficiency (although this could be taken into account at the time of the bid), and that therefore the generator could benefit from a higher than justified price when the electricity is actually delivered.

Another fundamental principle of EU free trade laws is that measures by national governments should not discriminate against products being imported from other countries. However, even this basic principle was thrown into some confusion by the *Preussen Elektra* case, in which the ECJ ruled that the nature of the electricity market, where once in the transmission system it is difficult to judge where the electricity has come from, meant that issues of discrimination did not apply. Nevertheless, Jacobs (2006) has again discussed the inconsistencies of this position, and because of this it would not seem to be one which could be relied on in the long term. At present the lack of interconnector capacity from the European mainland rules out electricity imports on the scale envisaged by LLECs, but this could change, and there is therefore an issue as to whether LLECs could be bid for by generators in Europe outside the UK. On non-discrimination grounds it might be difficult to prevent this, but the UK Government would need to decide whether such generation would satisfy its security of supply objectives.

In conclusion, this is an area in which some uncertainty remains, and which continues to evolve. Future developments in the ECJ and within the European Commission may alter the interpretation of some specific aspects, but in general the prospects for environmental protection measures within the EU market framework seem good. The aspects which are most likely to be of concern in enabling measures to fit in with EU free trade principles seem to be avoiding over-compensation, particularly given the time lag between making the contract and delivering the product, and allowing access to the mechanism from non-UK member states.

7. CONCLUSIONS

This brief paper has outlined some of the issues to be considered in thinking about securing low-carbon electricity generation in the UK through long-term, low-carbon electricity contracts (LLECs). Building on, and learning from, the experience of the NFFO, it seems that the idea is feasible, although its success depends critically on the Government clarifying the policy and planning framework within which LLECs would be implemented, as it now seems to be attempting following the Energy Review.

The cost of LLECs, using cost ranges in the Energy Review, does not seem likely to exceed 0.5p/kWh, and this would limit natural gas to 30% of the UK generation mix. It would also generate UK experience in a diverse range of low-carbon technologies (new nuclear, CCS, offshore wind, and possibly others) which might have export opportunities.

Doubtless many further details of this proposal would need to be elaborated before it could be taken forward, but on first analysis it seems to address all the energy challenges identified at the beginning of this note: of exposure to the price volatility of fossil fuels (their use would be reduced), of energy security (low-carbon generation tends to be more secure than fossil fuels for generation, although nuclear may give rise to different security concerns), energy reliability (it would ensure that plants were built and generating when they were needed), and carbon reduction (not least, to substitute for decommissioned nuclear plant). It would also do this by giving Government the choice of different low-carbon technologies for its LLECs, without having to second-guess their price, while ensuring that there were incentives for the least-cost technologies to be bid in the greatest quantities, thus enabling Government if it wished to minimise the cost of reducing carbon emissions.

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