ADDRESSING INERTIA IN CLIMATE CHANGE POLICY: THE POWER GENERATION SECTOR

A response on behalf of the BIEE Climate Change Policy Group to the Committee on Climate Change October 2009 Progress Report, and reiteration of our support for the notion of a government purchasing agency.

10 February 2010

Prepared by John Rhys, Mike Parker and Tony White on behalf of the Group[1].

The group generally welcomes the Committee on Climate Change (CCC) approach, which is wholly consistent with a number of the ideas we have advanced in the last two years. In particular we welcome the recognition, evident both in this report and in earlier reports from the CCC, of:

- the central role of electricity and the power sector.
- the limitations of markets in delivering a low carbon economy.
- the urgency of action to reduce emissions.
- use of "sectoral pathways" to define specific steps more closely.
- an emphasis on timetables to drive and monitor progress.

In this position paper we shall:

- comment further on policy inertia
- consider the CCC report as an opportunity to promote a strategy that could help to address and remedy the problem of inertia
- reiterate and expand our proposal for a purchasing agency as a component part of such a strategy.

The significance of this discussion is advanced further by the publication last week of the conclusions of OFGEM's Project Discovery report[2] which also highlights issues of market failure or inadequacy, and alternative options for reform in relation to supply security and environmental policy.

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[1] The authors take sole responsibility for any opinions expressed in this position paper.
[2] OFGEM. *Project Discovery. Options for delivering secure and sustainable energy supplies*. Feb. 2010.

CAUSES OF INERTIA

Real economic factors contributing to inertia in policy to reduce power sector emissions include the lock-in to an existing stock of long-lived fossil plant, the high capital cost and long lead times for low carbon investment, and investor reluctance to undertake large long term investments under conditions of regulatory uncertainty. There is also the reality of multiple and differing objectives for consumers, governments and investors.

In this context, inertia in dealing with climate issues also represents a market failure. There is usually an expectation that market responses to changing circumstances will be rapid, substantial and dynamic. However simple reliance on markets to deal with the range of issues driven by climate change, or rather by global policy objectives to limit human contributions to it, is invalidated, among other factors, by the difficulties in internalising the external effects of emissions - their true "costs" - in market prices. In consequence there is no reliable price signal to which the market can respond either in terms of demand or supply, nor is there a certainty in the regulatory framework that would make major investment easier to finance.

The consequences can be summarised by an annoying but incontrovertible truth of economic theory, and one of the most elementary propositions of welfare economics. "If damaging externalities are not internalised in prices, there is no basis to assume that economic liberalisation and free trade – ie markets - will ultimately improve human welfare."[3]

Given the scale of the potential externalities associated with climate change, the policy relevance of how the price mechanism operates in relation to emissions policy follows a fortiori. On the one hand, policy intervention to induce significantly higher prices, consistent with the high cost consequences of climate change, is a hard sell. On the other, without policy intervention to substantially internalise the costs of emissions, the continued operation of unconstrained markets may do serious harm by promoting more technically efficient, and hence lower cost and higher volume, use of dysfunctional, high carbon content, products and processes. "Market forces", unadjusted for large externalities, will almost certainly cause serious damage.

Policy makers have been reluctant to grasp this particular nettle for two main reasons:

First, objective analysis of the true "cost" remains a controversial process; it has been dependent on impossibly complex global modelling; it has been dependent on hypotheses, themselves open to challenge, about how global economies might develop under mitigation or "business as usual" scenarios; and it is open to unresolved debates over conceptual issues of trying to apply welfare economics principles on a global and inter-generational scale. The alternative approach, to fix a target or set of emissions targets, and to estimate what prices or taxes would be necessary to ensure their

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[3] This particular formulation is attributed to Michael Grubb, and is a quote from his recent presentation to the BIEE Parker seminar.

achievement, is a more realistic goal, but leads immediately to complex consideration and analysis of how to rank, cost and evaluate the various policy options across sectors.

Second, there are very real fears that raising prices or taxes, and hence costs to consumers or to particular interest groups, will undermine the degree of consensus so far attained on the need for effective action. Substantial lobbies consistently argue against actions that might impact on prices as they affect particular interests or sections of society, be it in relation to fuel poverty, energy intensive manufacturing, road haulage or air travel. Quota or trading schemes, one means of delivering prices that reflect the costs of meeting required emissions targets, may be constrained when they appear to have a major impact on prices. (We note for example the very limited achievements of the first phase of the EU ETS, and its comparatively small effect on the price of CO2 emissions.)

The outcome is that, even though policy makers, since Stern, have been clearly convinced that the cost of not seeking to mitigate the degree of climate change is high or very high, there has been a failure to establish a carbon price that reflects adequately the costs either of the externalities themselves or of measures of mitigation. The EU ETS, which can be seen as a partial application of this alternative approach, has not so far, even within the subset of total emissions it covers, delivered a carbon price sufficiently high, certain and long-lived to create a strong general low carbon incentive relative to fossil fuels. Fossil fuel prices are themselves inherently uncertain and volatile and this adds to the risk associated with low carbon investment.

Given this market failure in terms of the ability to reflect costs through into carbon prices, the alternative to simple reliance on market solutions is intervention by government, whether by regulation, by limited market interventions in the form of quotas and trading arrangements, or through various forms of direct intervention in investment or technology choice. In this context there will always be a high risk of further inertia as a result of multiple objectives within government and competing financial and administrative or legislative priorities.

The core problem is that inducing private investment in this environment, where the owners of low carbon generation plant may be exposed both to fossil fuel price and carbon price uncertainties, requires much greater assurance to investors in the form of some combination of contractual and regulatory certainties, and confidence in the level and stability of carbon prices. It certainly requires much more regulatory certainty in respect of the future carbon price than is currently available.

CONSIDERATION OF THE CCC ANALYSIS

We therefore share the CCC concern that the forces of inertia will prejudice the momentum of the transition to a decarbonised future. We believe that the problem is so important and difficult that only radical remedies will suffice. The CCC's first progress report represents a great opportunity to address this issue.

First, the excellent CCC analysis has the potential to promote momentum for low carbon generation: first by setting out the main elements of a "technology choice"(rather than simply assuming a product of market forces), thereby curtailing the delays involved in continuing debate on alternative scenarios, and second by identifying a clear sequence of time critical decisions. Moreover the summary of power sector indicators in Table 4.3 of the report is in effect an indicative framework that should guide strategic decisions. It will not be sufficient to regard these indicators solely as a means of monitoring progress (important though this is). Rather ways must be found to enhance the status of the CCC analysis as a strategic framework endorsed by government. This would minimise strategic uncertainty for investors and emphasise priority actions within government.

Second, given that the CCC recognises (p.136) that external price risk should be irrelevant in project appraisal for low carbon projects in a society committed to power sector decarbonisation, the removal of these risks would provide a strong incentive to investors in low carbon plant with very low marginal costs. Market structures therefore need amendment to allow long term contracts, with commodity price risk absorbed by the buyer, to be signed on the basis of competitive tendering.

Third the BIEE group proposal for an agency, acting as a single buyer, would have the great merit of creating direct links between the timing of key decisions in the indicative framework and the actual roll-out of lower risk investment projects, thereby reinforcing the required rate of progress of decarbonisation. It is thus essential that this particular institutional change is considered in the CCC's review of potential market interventions (Table 4.15, p.144). In the next sections we consider some of the alternative options suggested by the CCC report and we develop and reiterate our ideas for a purchasing agency.

COMPARISON OF ALTERNATIVES AND AGENCY PROPOSAL

It is clear that the options open to the government for direct intervention to deal with inertia and urgency in the critically important power sector are easier to define and more clear cut than in other sectors, notably in transport and in the heating of buildings. This reflects a number of factors: the inherently centralised nature of the power sector, at least as constituted under current technologies, the fact that power sector policies can be applied to a large degree within a purely UK context, and the comparatively small number of participants and concentrated nature of existing vested interests.

For this reason we have proposed the concept of an agency to promote decarbonisation of the power sector, and to shape and manage investment in the sector. This may not be the only plausible approach, but in the absence of ability to use the instruments of prices or taxes to full effect, we should at least consider an alternative means to address the key issue of power sector decarbonisation.

The CCC outlines a number of alternatives including the agency proposal, built around making markets work towards policy objectives, by *strengthening the carbon price* *signal, other means to provide confidence over the price received by low-carbon generation, and other forms of intervention to ensure investment in low-carbon capacity.*[4] These include our own proposal of a single purchasing agency. The options, not necessarily mutually exclusive, are examined in turn below, and the alternatives compared with our own preferred proposal of a purchasing agency.

Strengthening the carbon price signal

The CCC report suggests three main options for strengthening the carbon price signal:

- extend exemption from the Climate Change Levy (CCL) to all new low-carbon generators

- a carbon price underpin, eg by setting an auction reserve price at the EU level or using a carbon tax or contracts for difference to set a minimum UK carbon price

- feed-in tariffs for low-carbon technologies

The Climate Change Levy. Extending exemption is in our view an entirely logical measure within the current framework, since it would have a significant effect in "levelling the playing field" in respect of nuclear and CCS in comparison with renewables. The main issue is whether, at the current level of the levy, the effect on the economics of these first two low carbon alternatives would be sufficient to induce the additional investment required.

Carbon price underpin. This approach, in its alternative forms, is superficially attractive as a means of "fixing" the market to ensure sufficient low carbon generation. It carries two opposing risks. The first is that, since it will inevitably feed through into consumer prices, political pressures will prevent it from being set at a level that actually induces sufficient investment. In that case it could both incur significant costs (to consumers) and yet be ineffective, discrediting UK climate change policy in general. The second risk is that the price would be set unnecessarily high, generating windfall profits for new nuclear and CCS plants, and possibly also for some renewables. At EU level the underpin approach could also involve protracted negotiations within the EU.

Feed-in tariffs. These would guarantee a price for a fixed period for electricity generated by new low-carbon generators. In principle this suffers from similar disadvantages to those associated with fixing the carbon price. However in its practical application it has some advantages in that it could be calibrated and controlled with much more precision than the blunt instrument of a carbon price or tax. It could for example be banded for different sources; it might be confined to plant below a certain MW in size; and it might be a very suitable means of encouraging smaller scale decentralised generation. It might therefore be complementary to the use of other forms of intervention (central agency or

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[4] CCC Report, October 2009.

supplier obligation) to drive the large scale transformation required of the power sector as a whole.

Other forms of regulatory intervention

Emissions performance standards. Turning to regulatory interventions, one of the options included by the CCC to ensure investment in low-carbon capacity is to set emissions performance standards. These would entail regulation to specify a maximum emissions intensity (g/kWh) of generation, introduced at firm or installation level.

We believe there may be occasions when a regulatory prescription of this type is required, and it is difficult to evaluate this option except in the context of specific proposals as to scope and definition. However in general there are a number of potentially serious objections to this approach; essentially that it is too blunt an instrument, and that it risks introducing sub-optimalities into a complex generation mix. For example if CCS has a better economic potential and a bigger future role when applied to coal rather than oil or gas plant, then a badly designed regulation on emissions could inhibit a superior economic choice. Moreover this approach would be at its most unwieldy and potentially dysfunctional in the short and medium term, when we are still dealing with a large existing stock of, and possibly some new, fossil plant.

If applied at firm rather than installation level, it would need to recognise distinctions between generators specialising in peak or base load plant. If applied even more widely, to suppliers, it could avoid most of these difficulties but would then more closely resemble the low carbon obligation on suppliers, which is discussed below.

Low-carbon Obligation on Suppliers or tenders for low-carbon capacity

The CCC report suggests two further options:

An obligation could be placed on UK suppliers to source an increasing proportion of their electricity from low-carbon sources to ensure the required investment in low-carbon generation is undertaken. It could also be set to up to require that generators have sufficient installed capacity to meet the peak load of the customers they serve, plus a reserve margin. **or**

An agency could competitively tender for investment in low-carbon capacity, offering successful bidders long-term contracts free of commodity price risks.

The second of these is our preferred proposal. However the proposals have significant similarities. The first proposal would essentially transfer responsibility for planning a low carbon power sector to the (indeterminate) number of entities engaged in the supply business. It is highly probable that these supply businesses would seek to band together in order to manage the process; they would then either jointly plan or, at the very least, make arrangements to trade low carbon capacity and energy. Under the second proposal responsibility would be given immediately to the "central agency".

The first proposition is attractive in principle as a more decentralized and theoretically more “market oriented” version of the second. However there are in our view also some practical and general considerations that militate against it.

First and foremost it is becoming increasingly apparent that a very low carbon power sector will require very careful consideration of how to balance the potential contributions of intermittent renewable sources, nuclear (to some extent restricted for operational or economic reasons to baseload operation), CCS plant (possibly clustered to minimise costs of collecting and disposing of waste CO_2) and some decentralised power sources. Uncoordinated responses to a set of individual low-carbon obligations may produce sub-optimal or infeasible outcomes, implying either failure to meet targets or extra investment to remedy the situation. This approach may therefore raise competition issues by requiring degrees of coordination that are not really compatible with real competition in supply.

Second the requirement for a coordinated approach to supply will almost certainly extend to transmission and/or distribution planning and operation, which will further complicate the division of the low carbon responsibility between multiple agencies.

Third the degree of expertise needed to meet the responsibility of the low carbon obligation requires supply companies of sufficient size and sector experience to manage a very complex requirement. This would discriminate against smaller supply organizations lacking that institutional capability, and certainly hinder new entry into supply competition. By extending the scope of activities required of supply companies it could inhibit competition in the supply business.

Fourth, dividing the responsibility in this way would seem to require the development of some new market mechanisms (for inter-supplier trading of low carbon capacity) in order to be effective, and is a more complex solution, in institutional terms, than that of a single agency. The time lag to implementation could therefore be longer.

These objections can be overcome, but primarily or most naturally by allowing the separate obligations to mutate into a single collective obligation delivered by a single agency acting on behalf of all suppliers. We would propose moving immediately to such an agency rather than assuming it might evolve satisfactorily from the alternative proposal of low carbon obligations placed on multiple suppliers.

We have in earlier papers addressed some of the questions associated with building such an agency, but it is worth summarising the main features and issues here. There are clearly numerous options and variants to such an agency, and many of its detailed regulatory and statutory features would need to be determined as the idea was developed in conjunction with the key actors in the sector.

PROPOSAL FOR A LOW-CARBON PURCHASING AGENCY

Our proposal for an agency aims at an incremental approach to changing market structure, but is underpinned by the need for a policy instrument that "drives" investment in low carbon. It also seeks to retain the maximum of market and competitive features consistent with this objective.

Basic function of the agency

The basic function of the new "agency" would be to facilitate investment by:

- inviting competitive tenders to build low carbon generating plant with quantum and timing consistent with carbon budgets and the advice of the CCC on time critical pathways or timelines.

- offering successful bidders long term contracts free of energy commodity and carbon price risks in the form of power purchase agreements (PPAs), incorporating capacity payments.

This could be set in the context of action taken on behalf of suppliers, in order to meet their collective obligation, or the agency could act as principal, buying power from generating businesses and selling it to suppliers either under contract or, in certain circumstances, under a bulk supply tariff. We have set out in an annex a short note covering some of the principles likely to govern the negotiation of contracts with generators, set in a UK post privatisation context.

How contracts and competitive bidding would determine investor revenues and wholesale prices?

The proposed agency would issue invitations to tender for a given GW of low carbon generation over given numbers of years for each of a range of technologies.

It is also possible to envisage circumstances where some existing owners of fossil generation assets, or investors meeting very short term needs for additional fossil capacity, would also wish to secure contracts with the new agency, particularly if it was perceived as creating market uncertainties under current market structures. It is possible that this would result in a more rapid expansion of the agency's role.

Some general principles and issues influencing power contracts are set out in an annex. The agency would pay generators according to the terms of the contract. We would expect these to include:

(i) a regular capacity payment, fixed or indexed, over a contract life sufficiently long to remunerate the capital investment for capital intensive projects with low marginal cost (wind, marine, nuclear); this payment would form the major part of revenues for many types of generation

(ii) payments per kWh of output for marginal fuel or other variable costs (CCS, biomass), typically based on a fuel price index
(iii) incentive payments to reward availability and efficiency, structured to reflect the need for, or the market value of, any additional output; these payments would reward operational performance and penalise failure, and be linked directly to availability, or to output, allowing a market element linked to an SRMC-based wholesale market price
(iv) other detailed and technology specific rules governing scheduling and dispatch arrangements, which would be specific to the type of plant or even to the individual plant

Special arrangements could be included to avoid discrimination against small scale decentralised low carbon generation. For example small scale generation might form one of the tender categories, with its own procedures, or might be treated in the planning process as a negative demand.

The agency would sell its contracted power on a regular basis into wholesale markets with any imbalance between costs incurred and revenues received being cleared annually through network charges or a levy on all consumers. Such a levy may only be necessary if "market" prices are allowed to persist at levels below the "social cost" level that justifies agency intervention. Arguably, with fully priced emissions, the agency would generate a profit.

At some point the quantity of agency contracted wholesale generation would approach or exceed that of remaining non-agency existing plant so that it might be necessary or preferable to establish a bulk supply tariff.

What would be the interface with existing market arrangements and with nuclear and CCS plant?

<u>BETTA and the wholesale market</u>. This would continue to operate while the quantity of existing fossil fuel plant (without agency contracts) remained significant. The interaction between current arrangements for the scheduling and dispatch of plant, and the operation of plant under agency contracts, would need to be considered carefully. However there are a number of ways in which this issue could be tackled.

We should also note that the possibility of significant changes to the wholesale market has now been raised as an issue by OFGEM, particularly in relation to the issue of capacity payments and supply security but also in relation to low carbon investment. Insofar as the latter relates to perceived defects in the existing arrangements, the solutions need to be considered in close conjunction with the modifications that would arise out of an agency proposal.

The wholesale market, whether in the form of a pool or the BETTA arrangements, has as a prime function the organisation of adjustments of output (and demand), and the scheduling and dispatch of plant, to accommodate variations in demand and the availability/ performance of different generating plant. This feature would continue, certainly while there remained significant volumes of fossil plant, with the main fossil generators continuing to, in effect, bid into the market on the basis of their fuel costs, including any costs linked to the carbon price under a continuing EU ETS.

One possible scenario would have the generators under contractual supply obligations to supply, but trading with each other in a "generators' pool" in order to avoid penalties under the terms of their contracts with the agency, or to reduce costs by "buying in" from a cheaper source of supply. This retains the important feature of a competitive market in maintaining continuing pressures for efficient operation.

EU ETS. Existing generators, and any generators with CO_2 emissions, would continue to include CO_2 costs under ETS arrangements when bidding into wholesale markets.
If they entered into contracts with the agency they would need to take these costs, and their uncertainties, into account. Their contracts would probably specify prices for kWh output with a CO_2 cost pass through, passing the market price risk to the agency.

Renewables obligation. Existing contracts under RO rules would continue to apply but new renewable generation contracted by the agency would not receive ROCs and would not be included in the RO target for each year or the accredited generation.

Note. These observations reflect the inherently incremental nature of our agency proposal. We believe that, in the interests of urgency, there is a strong case for its introduction as soon as possible for all new projects qualifying as low-carbon generation. But as the rate of implementation would reflect the number of projects coming forward there can be an orderly transition, with existing arrangements continuing to apply to a declining stock of existing generation assets.

How would intermittent, nuclear and CCS plant be handled? All plant would be subject to scheduling and dispatch arrangements determined under the terms of the contract with the agency, which may allow for bidding into a generators' pool. Intermittent plant might normally be scheduled and dispatched by the agency/ system operator in such a way as to optimise its deployment taking into account its technical characteristics for intermittency and uncertain output parameters. Similar considerations would apply to any relatively inflexible nuclear plant.

CCS retrofits would be an outcome of competitive tender, in one of the main categories to provide low carbon capacity, and would be competing in this category with new-build CCS. Subject to its technical characteristics of operation being a reasonable approximation to conventional fossil plant, CCS plant would operate in any wholesale or pooling arrangements in the same way as ordinary fossil plant.

The wider context

We regard our proposal as progressive, seeking to retain the most important features of competitive markets consistent with a policy based on the need to deal with fundamental issues of market failure. We have advocated open contestable competition in the bidding for contracts and would propose to maintain in competition in supply, albeit this might de facto be confined to the supply functions such as metering and billing. We would envisage that the agency would seek bids based on carbon reduction targets, and then exercise choices over supplier and technology. In its tendering decisions the agency would reflect the outline created by the indicative framework that we have suggested above. In practice this is an inevitable requirement to make progress, in the light of existing policies on renewables, CCS and nuclear. The agency proposal is designed to make these policies effective.

We also believe that the existing market arrangements will in the longer term require very substantial modifications in order to accommodate very high percentages of plant that does not enjoy the conventional operating characteristics of fossil plant. Low carbon power generation cannot be handled efficiently within a market model that reflects first and foremost the needs of fossil plant operation, and does not deal well with the intermittency and inflexibility characteristics of much nuclear and renewable plant.

Our thinking is designed to be compatible with the most feasible rapid evolution of the electricity industry to full decarbonisation. While, as we have indicated above, the agency could continue to co-exist within the present market framework for some time, nevertheless the increasing importance of coordination issues arising from the cost and output profiles of low carbon technologies, the management of intermittency and storage, and changes in associated infrastructure, will raise, with increasing force, the question of the relationship between the agency and the system operator, and of both with the government and the CCC/ OFGEM.

Legal and Institutional Questions

We have hitherto been less specific on the legal and institutional framework for creation of a new agency, but there are clearly many possible options. The choice might need to reflect both political and presentational preferences. We should not be unduly constrained by existing regulatory structures and assumptions; internationally these are not the only ones that work well. The two main variants are

- the “EDF solution” with a nationalised industry taking charge of the power sector and integrating policy responses across the board. The EDF equivalent, even if it did not own transmission and distribution, would exercise substantial control over tariff structures and transmission as well as over capacity procurement.

- the variant we would favour; a more limited agency with specific remit and terms of reference, carrying out specific policy initiatives set out by the government on CCC advice; the agency would exercise substantial powers and authority but be subject to regulation.

Timetable and transitional issues

We recall how privatisation went from White Paper in 1988 to full implementation in April 1990, ie just two years. The creation of the 1990 market arrangements required a vastly more complex set-up of new market structures (the pool), completely new designs of regulation, and a massive legal structure of law, licences, codes and contracts. Our proposal by contrast requires far less in the way of new designs and is compatible with a more incremental approach, the most complex task being that of adjustments to an existing market process.

CONCLUSIONS

We are therefore proposing two complementary ideas to address the issue of inertia and inject momentum into the decarbonisation of the power sector.

The first is to enhance the status of the CCC analysis, and in particular Table 4.3 of the report, to that of a government endorsed indicative framework for the sector. The intention is to minimize strategic uncertainty for investors, and to identify and highlight priority actions within government.

The second is to create an agency, acting as a single buyer, one of whose main functions would be to invite competitive tenders for long term contracts that were free of commodity price risk and would incorporate capacity payments. Invitations to tender could be linked directly to the timing of key decisions in the indicative framework endorsed by government. This would both reduce regulatory uncertainty for investors and reinforce the rate of progress necessary to achieve long term targets. This proposal would incidentally address many of the market issues associated with security of supply concerns and identified in the recent OFGEM report.

The other proposals set out by the CCC, and the alternatives listed in the OFGEM announcements along with their own recognition of a central agency[5] as one option for consideration, are in our view less effective in reducing price risk for investors, and in providing a clear link to the time-critical decisions and coordination issues set out in the CCC analysis.

[5] Described as a central energy buyer in the OFGEM consultation, with a wider role encompassing gas as well as electricity.

ANNEX 1:
BASIC PRINCIPLES FOR GENERATION PLANT[6] CONTRACTS

Note by John Rhys. 20 July 2009.

Generation assets are typically **long lived, highly specific, and non-mobile**. The owner is therefore effectively committed to the particular market or even the particular buyer for the economic life of the plant. Reliance on a "market" which may to a greater or lesser extent be dominated by a local monopoly buyer or a powerful group of buyers means that generators who have committed to investment are always potentially at the mercy of decisions on new plant requirements made by their main customers, as well as changes in regulatory or market structure.

This all helps to explain why, historically, utilities were generally vertically integrated under some form of cost-plus or rate of return (RoR) regulation (eg in the US) or state ownership (eg UK and France). It also explains why, outside of a vertically integrated structure, or in a market, one would expect investors to prefer long term contracts. By their nature long term contracts tend to be quite complex, to contain arrangements for indexing costs, and protocols for dealing with significant changes in circumstances long after the contract is signed .

Why not long term contracts at privatisation?

Of course the UK 1990 privatisation did not result in long term contract structures, and a number of factors and consequences can be noted:

- There was a belief (whether justified or not) that this would contravene EU competition rules and be prohibited in Brussels (even though nowhere else in Europe had anything remotely approaching a competitive market structure).

- The system at that time still had significant excess capacity. This meant very low short term "spot" prices, hence without long term contracts much of the stock of generation assets would be sold for a fraction of its book value. However this was not important in the context of the time, when the owner of the assets was the government. The effect on public finances ("family silver") was not considered an overriding factor, and a smaller asset base would help depress prices.

- There was a political benefit to showing new entry, which long term contracts might have inhibited, even if this might appear to be wasteful, since it would show that competition was working. In fact the combination of new technology (CCGT) and cheap gas meant that there was a natural economic case for new entry anyway. The distribution companies were also keen to break their historic dependence on the CEGB and hence to break with its successor companies.

[6] The emphasis is on experience of fossil fuel based generation plant, although many of the basic principles will carry across to other high capital cost technologies.

- There was always an implicit desire to reduce the role of expensive UK coal. Long term contracts, beyond the three year initial protected arrangements, would have given rise to political pressures to continue protection of the coal industry.

- It was probably not widely understood that long term contracting, not "merchant plant", was in many ways the natural condition of the electricity sector.

- There were early and substantial movements to try to re-establish the vertical integration of the industry through mergers and acquisitions. Nevertheless in spite of this, and the "dash for gas" investments that characterised the 1990s, increasing concerns have been voiced that the market will not necessarily deliver adequate capacity and security. BETTA has in the views of many people (eg Dieter Helm) compounded the problem by abandoning the main mechanism of the 1990 pool that was put in place specifically to deal with the generation security issue of adequate capacity.

<u>Contracting principles</u>.

The relevant economic principles for contract formation can be very simply stated:

- The division of risk should be such that each risk rests with the party best able to "manage" or control that risk; the party concerned then has the incentive to manage it effectively; these incentives may be implicit in the transaction or they may be the subject of explicit incentive arrangements within the contract.

- The payment structure should be consistent with encouraging the most efficient use of resources. In particular, from the perspective of a central agency, it means that the contract should be consistent with the agency being able to "call the contract" or economically dispatch the plant in merit order.

- Performance incentives and penalties should not be incidental by-products of contract negotiation, but should be geared to the market price or economic value of any incremental output gained or lost.

These principles have to be applied to the actual cost structures and technical characteristics of generation plant. ***In the case of fossil plant*** this can usually be stated, in simplified form, as a large fixed capital cost component associated with construction, often expressed as a value per GW, MW or kW of capacity and a large fuel cost which varies directly with output and is expressed as a value per GWh, MWh or kWh.

Efficient operation of fossil fuel based systems is built around scheduling and dispatching plant in ascending order of incremental fuel cost, (SRMC), with the SRMC of the last plant to be called upon constituting the system marginal cost (SMC), and representing the economic value of incremental output.

Finally the contract and/or licensing arrangements need to deal with the relationship between the individual plant and the system operator, and with the implications of any particular technical features of the plant.

NB. Conceptions of system marginal cost may need to change quite radically in a future where there is no simple calculation of optimal short term scheduling and dispatch through a simple merit order ranking. It is not just that there is likely to be plant with zero or negative incremental costs. Optimisation of systems with hydro storage for example may only be possible through algorithms that work over much longer seasonal periods

Consequences for the form of contract to be expected as outcome of negotiations

Capacity or MW payment. The owner/investor, and its financial backers, will want a high degree of certainty about the long term basis of their revenue stream under the contract. So a contract under which the investor builds, owns, operates and sells the output of a plant, as opposed to merely building (with immediate transfer of ownership to a buyer), will normally include a large payment element intended to cover capital costs, including financing. One would expect this to be spread over the life of the contract, since the generator is delivering capacity over a long period, and to be expressed as a price per MW. The risks associated with construction are born by the investor, since the buyer can do little to influence or control construction costs.

The investor's risk bearing will normally extend to plant availability, since the buyer will not want to pay for capacity that is not available, and availability risk should properly be managed and controlled by the plant operator, and may also be determined in part by the quality of the initial construction. The MW component of the contract payment is therefore likely to be subject to achievement of a target availability, typically measured either by output, for baseload plant, or availability testing, for peakload plant.

However the generator will not carry demand risk, since this would normally be deemed to be more capable of management by the buyer, who will be responsible for forecasting demand and anticipating market conditions, and may build or enter into contracts for additional plant, which would automatically reduce the need for actual output under the contract with which we are concerned. So subject to satisfactory availability performance, the generator will get paid the MW payment regardless of how many hours it is actually called upon to generate.

Energy or MWh payment. In addition there will need to be a payment for actual MWh generated to cover the variable fuel costs of the generator. However if the contract payment exceeds the actual variable costs, then the buyer, eg a central purchasing agency, will no longer have accurate information on what plant to use first, and this will result in seriously inefficient operations and major departures from least cost. So the MWh payment under the contract will not normally attempt to build in any of the reward to the initial capital expenditure; nor should it contain elements other than those linked to short run operating costs.

The actual definition of the MWh contract price will however need to be specified in a form that allows for movement in actual fuel prices, eg through an index for the fuel type on which the plant runs. This means that fuel price risk is born by the buyer. It is possible to argue that neither party can control fuel price risks. However the buyer under the contract will be dealing in a wholesale market in which the overall level of prices will tend to reflect fuel price changes, and also has an opportunity to pass on fuel costs to consumers, the real ultimate repository of fuel price risk.

However the actual costs of generation depend not only on fuel prices but on the thermal efficiency of the plant, which depends inter alia on maintenance and is managed by the seller. Under this arrangement the seller continues to bear/ gain the risk/ reward associated with operating efficiency that differs from what is anticipated in the contract.

A good example of the problems that arise with a single part tariff for electricity contracts arose in the 1908s and 1990s with the sale of power from central generating boards of the federal Government of India (GoI) to the state electricity boards (SEBs). This was under a one part price per MWh tariff, with the result that the SEBs dispatched their own inefficient plant in preference to the more efficient GoI plant.

Incentive structures. To some extent this type of contract already has a number of broadly correct incentive properties for the plant operator – to meet availability targets, to improve on contracted thermal efficiency and hence lower its fuel costs (since it will get paid the contracted rate).

However if we assume that there is still a spot market associated with dispatch, whether a conventional pool with demand side participation or a "generators' pool", then we can see how the incentives can be set up to be directly related to the market price as it manifests itself in system marginal cost or SMC. Generators can be rewarded for extra output, or penalised for failure to meet contractual targets at SMC, if they are allowed to sell into this market any output surplus to their contractual commitments / targets and to meet their contractual targets by "buying in" amounts to cover any deficits. This means they have a direct incentive to improve operational performance at the margin which is driven by current market conditions rather than complex incentive structures set up in a contract.

If for example a generator has contracted to supply 1000 MW over a particular period, but has temporarily reduced availability or fuel efficiency, it may be more efficient to meet that target by buying in power from other generators rather than advancing maintenance expenditure.

Summary. Overall this kind of contract structure, with a pool or wholesale market linked to dispatch, results in the correct allocation of risks, each risk to the party best fitted to carry it, and also retains the "market" disciplines to maximise operational efficiency in meeting daily demands for energy at the lowest possible cost. It meets the need for the purchasing agency to be able to call on plant in merit order.

ANNEX 2: Remit and Membership of BIEE Climate Change Policy Group

The Climate Change Policy Group originated from the BIEE Parker Seminars, in order to reflect and articulate some of the ideas that were emerging from discussions in that group. This remains the basis of its association with the BIEE. It does not claim to represent the views of the BIEE as a body, or of the BIEE membership as a whole. Any views expressed here are solely the responsibility of the members of the group, or of the named authors or contributors.

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