CAN UK ELECTRICITY MARKETS DELIVER A LOW CARBON FUTURE? FINDING THE WAY FORWARD.

BIEE OXFORD CONFERENCE. SEPTEMBER 2010.

John Rhys. Senior Research Fellow, OIES

INTRODUCTION

The starting point for this analysis is two observations on the prospects for achieving a low carbon economy in the UK. The first is that the role of the electricity sector is absolutely central and is hugely important to almost any strategy for achieving this objective. The second is that there is now considerable scepticism about the efficacy of competitive markets, as currently constituted, in delivering a low carbon future - the consequence of a number of current and potential future sources of market failure.

The central role of electricity derives in turn from a number of very simple observations:

- the power sector currently accounts for some 35% of UK CO2 emissions, and the share would be higher without current nuclear and renewable contributions.
- the second largest and fastest growing source of emissions, accounting for another third, has been the transport sector, where the main technology alternatives, at least for road transport, are electric or hydrogen solutions, both dependent on a substitution of low carbon primary electricity for fossil fuel.
- electricity plays a significant current and potential substituting role in other sectors – heating of buildings and in industrial processes such as metal melting – conventionally assumed to be dominated by direct use of fossil fuel.
- electricity is often the only economic vector for non-fossil sources of primary energy.

This contradicts the traditional arguments sometimes presented on environmental grounds, but usually driven mainly by anti-nuclear sentiment, that electricity is a relatively unimportant component of the energy mix. However this central role will, to most serious analysts, now be seen as an incontrovertible fact.

On the second starting point, scepticism over the effectiveness of the current market structures for the UK energy sector has been a feature of several recent reports and consultations, including the recent OFGEM consultation on gas and electricity markets. This was seen as radical and controversial because, in a context of security and sustainability objectives, it questioned the efficacy of markets. In this it reached a very similar set of conclusions[1] to the Committee on Climate Change. Both analyses confront

[1] *Meeting Carbon Budgets. The Need for a Step Change.* Progress Report to Parliament from the Committee on Climate Change. October 2009.

the continued validity of a post 1990 paradigm in which competitive markets are expected to resolve all problems.

The UK has taken justifiable pride in its particular intellectual and technical contribution to international thinking on power sector issues and reform, in creating functioning electricity markets for predominantly fossil-fired plant. To retain intellectual leadership in this field it should now be considering how best to adapt both to a changing technical environment (post fossil) and a changing policy environment (the CO_2 externality).

Part One of this paper demonstrates that concerns on the efficacy of markets are in this context very well founded and that the central role of the power sector in achieving targets for reduced CO_2 emissions should imply a radical reappraisal of market arrangements. Part Two attempts to develop some ideas on how this might be addressed in order to retain the best features of competition while addressing some of the sources of market failure.

PART ONE. A CRITIQUE OF ELECTRICITY MARKETS IN RELATION TO LOW CARBON POLICY OBJECTIVES.

A first step is to examine more critically the sources of the benefits, in lower costs and prices, that have accrued under the post 1990 market regimes.[2]

POST 1990 EXPERIENCE. ASSESSING THE GAINS FROM REGULATION, COMPETITION AND OTHER FACTORS

It is the attribution of the efficiency gains and substantial cost and price reductions following the major market reforms and privatizations in 1990 that largely drives argument over the advantages of current market arrangements, and especially over particular features such as the forms of electricity trading or supply competition. Defenders of the status quo on markets implicitly attribute a substantial part of past gains to the current structure of trading arrangements rather than to the body of 1990 reforms as a whole; this conditions any assessment of the costs and benefits associated with more radical changes to current trading and market structures.

However a very high proportion of historical efficiency gains and falls in consumer prices post 1990 derived directly from factors which cannot legitimately be ascribed either to particular features of the market structure or even to the existence of a competitive market per se. In particular, and taking the whole period since 1990, the most important factors promoting lower costs and prices included:

- elimination of high cost UK coal, which disappeared as initial vesting contracts were phased out in the 1990s. This reflected abandonment of the policies of successive UK governments in forcing the electricity industry, the CEGB, to support the UK coal industry. Privatisation and competition may have provided a convenient cover for this policy change, but this gain would or could have occurred under any form of regulated or competitive industry.
- the simultaneous advent of relatively new technology in the form of combined cycle gas turbines (CCGT); since this was and is an international technology, the innovation and its development cannot be ascribed wholly or in part to UK market liberalisation.
- combination of this factor - CCGTs - with a period of low energy commodity prices, and cheap and plentiful gas.
- very substantial increases in efficiency, and cost reduction, in natural monopoly elements of the sector, especially distribution costs; these however were driven by a combination of regulatory and private sector incentives, not by market arrangements for generation and supply.
- with CEGB assets sold off at below book value, and significant capacity surpluses through much of this period, both the need and ability to earn a full return on the capital value of historic investment were largely removed.

[2] This part of the paper is developed largely from the author's response to the OFGEM consultation earlier this year and a short article prepared for Oxford Energy Forum in May 2010.

These factors should condition any assessment of the effectiveness of competition per se as the prime driver of efficiency and cost and price reduction.

There is nevertheless evidence, especially post 1990, of significant improvements in generation efficiency, most notably in power station operation and availability, driven partly by competitive market pressures and partly by disciplines arising from private ownership of the facilities. This was reinforced by reductions in concentration within the industry in the late 1990s, driven by post-1990 competition policy concerns.

However it is very hard to argue convincingly that even these gains resulted from *particular* characteristics of the competitive market structure and rules since 1990 or 2000, and certainly not from the particular feature of supply competition per se, the component of the competitive framework most directly affected by more radical reforms such as a supplier obligation or a central buyer. Indeed Green[3] has argued that retail competition can raise wholesale prices, corresponding to reduced efficiency and ultimately higher consumer prices, in comparison with a market based on long term contracts and a regulated supply business.

One further factor deserves mention – the 2001 NETA changes. Inter alia this removed the element of capacity payment, with an inevitable short term downward effect on prices. However failure to provide an alternative means to reward capacity contradicts the fundamental economics of the power sector, especially the link between market driven prices and investment. It is now widely held to be[4] a significant part of the security of supply issue.

We should not therefore assume that established advantages and benefits, accruing from a structure built around competition and private investment, would necessarily be compromised even in quite major modifications to the current structure.

CRITERIA FOR A WELL-FUNCTIONING MARKET

A well-functioning market for the future, and its associated regulatory framework, **must** inter alia:

- induce efficient behavior from participants, leading to optimal scheduling and dispatch.
- generate price signals for allocative efficiency in production **and** consumption
- internalize the costs of any continuing CO_2 emissions.
- deal adequately with the coordination requirements in transmission planning and system operation.
- above all, provide a secure basis for the large scale and long term investments required to move the power sector to near complete decarbonisation.

[3] *Retail Competition and Electricity Contracts,* Green , December 2003
[4] eg *Hot air, gas prices and energy policy,* Dieter Helm, December 2005.

These are the main criteria that should inform judgements about the efficacy of markets. With these in mind we can consider several particular issues for the operation of markets in the context of policies to promote low carbon electricity generation.

TECHNICAL REQUIREMENTS FOR TRADING AND SYSTEM OPERATIONS IN A LOW CARBON NON-FOSSIL FUTURE.

One of the great technical achievements of the radical market design for the 1990 privatisation was that it successfully replicated the operational optimisation embodied in the CEGB merit order structure into a market bidding arrangement. Without this feature the market would have been substantially and visibly less efficient at its inception, undermining claims for the virtues of competition and private sector disciplines in promoting efficiency. It was a pre-condition imposed on the market design.

It also demonstrates the link between the technology of power generation and market structure. Pre-1990, system operation was based on deployment of flexible fossil fuel plant that could respond to meet continuously changing demand for a non-storable commodity. Central control scheduled and dispatched the lowest marginal cost plant in ascending order of merit. Post 1990 this worked through a bidding process which, conceptually at least, encouraged players to bid at marginal cost, and corresponded exactly to the merit order ranking employed within the command and control system of the CEGB. Notwithstanding the NETA modifications to trading arrangements, this close connection remains.

However a future low carbon world is likely to have very different plant operating characteristics, dominated by relatively inflexible plant (nuclear), plant with intermittent and/or stochastic characteristics (renewables), and in the medium term much greater opportunities for positive/negative storage through different types of more flexible demand (eg to serve the transport sector). Faced with very different technical and economic characteristics, where a high proportion of plant may have zero marginal cost but technology specific limitations on flexible response to load changes, electricity markets and system operations will need to be defined very differently. Efficient system operation for example may depend on more complex forms of optimisation defined over weeks or months rather than hours or days.

Some issues associated with current arrangements have already been highlighted in the Poyry report[5], paradoxically the problems for viability of fossil-fired generation dependent on price spikes and infrequent operation, resulting from intermittent wind power. We should expect new problems as both the number of new non-fossil technologies and their contributions increase.

Optimising the operation of generation based largely on a variety of non-fossil or non-thermal technologies is inevitably a much more complex task than simply stacking the short-run marginal costs of generating plant in a one stage, one price, auction process. If

[5] *How Wind Variability Could Change the Shape of British and Irish Electricity Markets*, Poyry, July 2009

it is amenable to an auction process at all, it would probably be to a multi-stage auction with complex structures and no very clearly defined output of a single "price" for each period.

We cannot assume therefore that a market built around the notions of daily or half-hourly optimisation and pricing will remain "fit for purpose", or that the current structure is capable of incremental evolution to a new and more complex system of market "auctions", let alone any bilateral trading equivalents, that will still deliver short-term operational efficiency.

This emphasises the central importance of having market arrangements that are compatible with the predominant technologies of the day. If we are seeing an evolution towards a set of technologies with very different operating characteristics, both on the supply and demand side, then we shall need very different market structures. We cannot assume a natural incremental evolution from the rules that exist today, or even that a similar market structure will be possible or optimal.

PROBLEMS IN SECURING LOW CARBON INVESTMENT AND ADEQUATE CAPACITY UNDER CURRENT MARKET STRUCTURES

Both OFGEM and the CCC have correctly focused on the primary issue for market arrangements as being how to ensure high and unprecedented levels of investment, to meet both security and low carbon targets, all against a background of an aging plant stock. Several difficulties exist and are apparent in current market structures.

Perverse treatment of financial risks.[6] OFGEM correctly observe that "*investments with stable operating and fuel costs (such as nuclear and wind) could be viewed by … suppliers as more risky than investments whose costs vary with volatile global fuel costs*." Fossil fuel plant will continue to be at the margin for some time and hence to set price. So fossil plant gets a degree of protection (varying by type of fuel and efficiency) equivalent to partial pass through of fossil fuel price volatility. This intrinsically discriminates against non-fossil plant; a pass through of fuel costs for incumbent forms of generation creates a barrier to entry of new technologies.

Asymmetry in treatment of capacity risk. Another unsatisfactory feature of current arrangements is the fundamental asymmetry between the risks of under and over provision, and in particular the conflict this creates between market and social objectives for the power sector.

From a societal perspective, the net costs of over provision may be relatively small. There is a significant resource cost in over investment, but it is partially offset by earlier retirement of less efficient plant. Under provision on the other hand is commonly seen as near catastrophic. Inelastic demand is not choked off by prices, and the outcome is

[6] I am indebted to the late Dennis Anderson, among others, for this insight. See: *Electricity Generation Costs and Investment Decisions*, UKERC Working Paper, February 2007.

load disconnection and potentially widespread loss of output across all sectors of the economy. It is a “market failure” that cannot be ignored by governments.

However, from an individual investor perspective, and in the absence of long term contracts, it is over-provision that presents worse outcomes, through a collapse of prices. Restoring equilibrium by closing capacity invites regulatory intervention on competition grounds. Under provision, by contrast, implies higher prices and better returns.

This asymmetry was balanced in the1990 arrangements through market mechanisms established specifically to provide continuity[7] in security of supply - a penal incentive requirement on public suppliers to buy in the market up to a price intended to reflect the value placed by consumers on secure supply - the Value of Lost Load (VOLL). This feature was discontinued under NETA, abandoning a fundamental link between setting a security standard and explicit assumptions about the costs of system failure.

In the context of low carbon investment, this asymmetry is even more pronounced. Over-investment implies over achievement of sector carbon targets, and hence more carbon-efficient operation of the sector. Within a rationally administered framework of national targets this would in principle allow more carbon allowances to be “spent” in sectors such as aviation where consumers implicitly attach a much higher value to their use of fossil fuel and resulting emissions.[8] Given that current carbon emissions are typically valued or priced at well below most estimates[9] of their social cost, this would be a large offsetting social gain, albeit one whose incidence may be very diffuse.

Background of uncertainty. OFGEM suggests one problem is a heightened perception of risk and hence high costs of capital. However nominal interest rates are at an all time low, and according to most of the canons of modern finance theory, investment in well regulated utility industries, with risks that are not heavily market correlated, should be low risk and low beta. Anything else implies lack of confidence in the regulatory framework. The real difficulty therefore is in attracting high levels of investment against a backdrop of ***contractual*** or ***regulatory*** uncertainty.

The most obvious historical parallel for a high investment transformation of the power sector in a modern economy is the highly successful decarbonisation of the French power sector in the 1980s and 1990s, the scale of which was certainly comparable to the challenge facing the UK today, and which was accomplished primarily through the state sector (EDF).

A more convincing statement of the problem, therefore, is to consider ***how the necessary and very high levels of investment can be achieved through private investment and an appropriate balance of regulation and competition in electricity markets.***

---

[7] The old CEGB “three winters in a century” of insufficient capacity was deemed to correspond to a consumer valuation of £ X per kWh so that a penalty of the same value of £ X on suppliers’ failure would result in the same security outcome as under the CEGB regime.

[8] *Meeting the Aviation Target. Options for Reducing Emissions to 2050*. Report from the Committee on Climate Change, December 2009.

[9] The Stern review and other sources.

Carbon prices. Markets, essentially through the EU Emissions Trading Scheme (ETS) have so far failed to deliver carbon prices that are sufficiently high and stable to support necessary investments in low carbon generation technology. This may reflect unwillingness by governments to countenance adequately tight emission limits, and this has led to consideration of carbon price fixes as one possible solution.

Coordination. Finally, in parallel with the system operation issues posed by new technologies, there are analogous questions of coordination in relation to choice of investment: to determine what combinations and proportions of technologies in the generation capacity mix are technically feasible in meeting future load patterns. Coordination issues also include incorporation of decentralised options, along with their associated infrastructure requirements, choice of sites for wind power, to maximise diversity, and for CCS, to minimize new infrastructure costs for pumping and storage of captured CO_2. This suggests a possible need for an overall investment framework, in the form of additional powers and responsibilities for the National Grid, or for a new power purchasing agency with responsibility for ensuring adequate capacity and meeting sectoral emission targets.

PART TWO. FINDING THE RIGHT PATH TO EFFECTIVE REFORM.

Part I above identified the main problems in achieving essential investment as relating to

- carbon prices, and contractual or revenue certainty for investors,
- potential inadequacies in system operation and trading linkages, as the sector moves away from conventional fossil technologies,
- the coordination and timing of investments in capacity and infrastructure, and
- adequate incentives to ensure security of supply.

OFGEM and the CCC concentrate on the first and fourth of these problems, and propose alternative approaches to reform, on a spectrum from incremental changes to existing trading arrangements, including very significant measures such as a carbon floor price, to more radical institutional changes, such as additional supplier obligations or a central agency. However it can be argued that the essential strategic choice is a binary one, between reliance on a series of possible "fixes" to correct deficiencies in existing market structures, and introduction of formal obligations to provide adequate security and meet emissions targets.

The analysis above suggests that the first approach has several deficiencies: the general problem of trying to second guess markets, the potential proliferation of complex additional rules, schemes and instruments, and failure to address the implications for market structure of fundamental technology-driven change in the sector, all of which will add to investor uncertainty and carry significantly higher risks of not delivering on the objectives.

The more radical options, for a supplier obligation or central agency, are similar, in that the first might naturally evolve into the second with suppliers creating a jointly owned agency to meet obligations, and in that both tend to imply limitations on supply competition. Such an agency offers the most certain prospect not only of securing an adequate quantum of low carbon investment, as well as supply security, but also of securing a balance of different types of capacity and load management options compatible with secure and efficient system operation, and of coordinating that with the necessary infrastructure investments.

The agency would in effect become the major purchaser and wholesaler for the sector, inviting tenders for new capacity, and coordinating its programme with associated infrastructure investment by the National Grid. With properly designed and implemented tendering procedures and contracts, this would retain both competitive pressures in building new plant and incentives for efficiency in operation. Its obligations would encourage a diverse balance of capacity types technically compatible with maintaining supplies, and higher reserve margins to ensure adequate security.

Competition in retail supply could continue but would have to focus on competition in the true supply functions of providing a billing service, rather than exploiting consumer inertia or lack of information as to the true wholesale price of electricity as a commodity.

As a purchaser and wholesaler the agency would also provide a natural channel for support to innovative solutions in the sector, including economically viable decentralised generation capacity. It would also be able to contract for existing capacity, and this would help to encourage a natural transition from existing commercial arrangements.

This part of the paper is intended to articulate in more detail how a central agency[10] might operate and how it might interact with existing market structures. The concept is not new, has frequently been proposed in other administrations, and is particularly useful in electricity systems where a "fully competitive" wholesale market based model is ruled out either on practical grounds (eg small systems, stranded assets etc) or because full competition leaves governments with an inadequate set of alternative policy instruments. In the current context we can consider relevance to low carbon and generation security issues.

Simply in terms of market mechanics, it can be designed to have important features in common with the fully competitive model. Early versions of the 1990 England and Wales privatisation model, considered in the industry negotiations but discarded in order to enhance full supply competition, were in effect based on the notion of a single buyer function exercised jointly by the twelve distribution companies. Under this scheme the twelve would forecast their own requirements and make separate contracting choices before pooling their contracts for operational purposes. One proposed scheme, the distributors' pool, would then have had the National Grid dispatching generation plant under contract.

An alternative, close to the solution finally adopted, was based on a "generator's pool"; this was intended to allow generators to collectively meet their scheduling and dispatch arrangements by trading through an actual or bid based (as opposed to contractual) merit order so as to maximise efficiency. The latter was eventually modified in relatively minor ways to create the actual 1990 market structure, inter alia by formally ensuring the pool was open to a wider range of participants. In an interesting parallel with some of the issues and possible solutions now emerging in relation to electricity markets, the National Grid was initially established under the joint ownership of the twelve distribution companies.

The above demonstrates that the concepts of central purchasing and organisation have not been totally alien from, indeed have at times been accepted as integral to, the development of the UK model of a competitive industry structure. The remainder of Part Two of this paper describes some of the options for how a future central agency might

[10] We generally and deliberately avoid the term "single buyer" simply because it has acquired a huge emotional baggage of association with vertically integrated state monopolies such as the CEGB. As this note is intended to show there are a variety of ways in which this model can be developed or refined to allow more or fewer degrees of control to the agency itself.

work in a little more detail, considers the interface with existing systems, and attempts to answer some of the more common objections raised to the concept of coordination within a market structure.

OWNERSHIP AND REGULATION

Option A. Recreation of State Owned and Vertically Integrated Industry.

This would be a traditional nationalised industry model, a publicly owned and vertically integrated monopoly, strongly resembling the old CEGB or EDF model. As such Option A is unlikely to command much support, even though it can be argued that EdF in particular had an unequalled record in driving through massive, and low carbon, changes in the primary fuel composition of the French power sector, ie just what is now required in the UK . It would necessarily be a new body, and would have to be established by statute.

Option B. A Public Enterprise with a much more limited remit.

This would be similar to Option A, except that it would not as a general rule own or operate generating plant, or control transmission or distribution.

Option C. Joint ownership by suppliers

This would be a new body, with duties and regulatory oversight of it perhaps determined by statute and/or new regulations and licence conditions, but owned jointly by the largest suppliers, the Big 6. This would be akin to the ownership model for the National Grid, as implemented with privatisation in 1990. As such it has recent historical precedent.

This body could be created from scratch by statute, or it could be created as an initiative of major suppliers. In terms of financial viability, this might have some attractions, since it would be underpinned by the main players of the sector.

Option D. Owned by and fully integrated with the National Grid.

This is a proposal that has some obvious logic in simplifying the contractual issues necessary for a system operator to exercise "command and control" on technical matters and to optimise operations, and in coordinating infrastructure requirements, thus meeting Objectives Two and Three.

Option E. Stand alone, but in private ownership.

This has the advantage of clear independence from suppliers and government, but as a privately owned body, it might be seen as excessively exposed to financial risk, and not an attractive investment. However this would depend critically on the regulatory protection and safeguards that were put in place.

Option F. A Government Department.

Few people would normally suggest this as an option, but it is a possible default option. It could be useful as a "first step" in order to push forward with important and immediate initiatives pending a proper institutional reform.

SCOPE OF ACTIVITIES AS BUYER

Option A. Minimal responsibilities confined to dealing with power purchase agreements and bulk supply tariffs or other contractual means by which suppliers purchase power, only for new low carbon plant. Operating under guidelines from government, regulator or a committee of major suppliers who would individually retain responsibility for forecasting total requirements, which could be expressed through their capacity contracts.

Option B. Responsibility for new and existing plant contracts, both low carbon and fossil; some obligation to ensure sufficient capacity to meet security and low carbon objectives, but without any monopsony rights as a "single buyer".

Option C. Ultimately becoming the only body responsible for contracting for new capacity, with fewer or very limited exceptions, typically for large industrial consumers. Correspondingly, strongly worded duties to ensure sufficient capacity and meet carbon objectives.

OPTIONS FOR REGULATION.

This would need to reflect key concerns over performance. Rate of return issues would be relatively unimportant, since the agency itself would not "own" many assets, but the three key areas would be:

- strategic choices, eg as between nuclear, CCS, renewables and decentralised generation.
- adequate forecasting performance, although this would be less important if it operated simply by accepting contracts to provide capacity from suppliers.
- engaging in effective, transparent and non-discriminatory procurement, for example through use of competitive tendering.

Option A. Additional responsibility for OFGEM. This would be a natural extension of regulatory responsibilities for the sector.

Option B. Accountable to other parties with responsibility for delivering a low carbon outcome, eg the suppliers as joint owners, or to DECC.

Option C. Treatment simply as an arm of government. Supervision through the appropriate department – DECC, and reliance on a National Audit Office (or formerly on an Audit Commission).

CONTRACT FORMS FOR POWER PURCHASE AGREEMENTS

Contract forms are invariably subject to a great deal of detailed design and negotiation, and would vary significantly by type of plant, particularly as between intermittent plant, nuclear plant and residual fossil (with or without CCS) plant. Nevertheless there would be significant common features, such as some form of guaranteed capacity payment. There is a wealth of national and international experience in the writing and negotiation of such contracts.

We should expect the most significant negotiations to be around who bears which risks under the contract. This would follow the general principle of risk being assigned to the parties most responsible for, or best able to manage, those risks. Where market risks are concerned, it is quite unreasonable to assume that any investor in “merchant plant”, ie without a long term contract or tied customer base, will take price or volume risk when both price and volume can be affected directly by the decisions of either a single purchaser or a small group of purchasers. The purchaser or purchasers will inevitably accept this risk and place it with customers. The likely division of risks is along the following lines:

- Market price risks, ie mainly future fossil and CO_2 price risk - to the single buyer, but with a strong recommendation that incentive payments might reflect current market conditions as they developed throughout the life of the contract.
- Weather (for intermittent plant) - to the single buyer
- Construction cost risk - to the plant operator
- Availability and plant performance – to the plant operator
- Demand risk, ie of capacity surplus or deficit – mainly to the single buyer

We might expect to see the following as major features of the contract with the generators successful in the tender;

- Regular capacity payment, fixed or indexed, over a contract life sufficiently long to assure reasonable prospect of securing adequate return on investment.
- kWh payment per unit generated intended to cover fuel costs or marginal costs of generation, for the types of generation where this was appropriate.
- incentive payments to reward operational performance and penalise failure, either linked directly to availability, or to output, allowing a market element linked to an SRMC-based wholesale market price (when this can be determined).
- 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.

The contract could be written to allow the purchaser the means to allow the system operator to “call” for output as part of the operator’s responsibility for short term optimisation and system stability. In the medium term this would almost certainly be necessary to replace current spot market structures.

TENDERING PROCESS AND PROCEDURES

There is a wide variety of approaches to tendering and procurement, covering all aspects from tender specification through the bidding process rules, and on to award criteria and negotiation with the successful/ preferred bidder. Variants develop in at least two important respects: the extent to which particular tenders specify technology, and the process for selecting and negotiating very large contracts, particularly where there may be only a small number of firms capable of tendering.

On specification, issues include:

- whether all tenders are potentially open to all types of plant, or with quotas for different technologies, eg nuclear, renewable, CCS, or a combination, eg set minimum quotas plus an "open" category.
- whether tenders are banded by CO2 per kWh
- the basis on which quotas are decided.
- whether tender specifications remain the same for all categories, or whether they are differentiated by category

On process a few of the important questions are:

- use of prequalification to set minimum standards for technical competence and financial viability
- how far to pre-specify contract terms in the invitation to tender, and how far to encourage innovation in contract bidding
- management of situations with small number of bidders
- treatment of price/ quality trade-offs
- parameters for negotiations with final bidder

ONWARD SALE TO SUPPLIERS

There are two main options for this, closely linked to how the agency purchases power, ie on its own responsibility or in response to capacity and energy contracts placed by suppliers:

- Sales under a multi-part bulk supply tariff, where charges would reflect the costs of supply, probably differentiated over the day and over the year, and including due account of capacity requirements and the load factors of electricity purchased
- Sales under long term contractual provisions; this would oblige the supply companies to make forecasts of their own requirements and sign contracts accordingly – sometimes known as a "contracted capacity" approach.

ANSWERING COMMON QUESTIONS AND OBJECTIONS TO AN AGENCY PURCHASER MODEL

Q. This approach means that risk, which ends up as a cost, is transferred to and has to be born by consumers, rather than by investors in a market. Surely this is unacceptable?

The fundamental components of commercial risk in the sector do not go away because they are born by investors; the latter typically charge a risk premium, or require a higher rate of return on capital to cover the risks they face. So in the end the cost of irreducible intrinsic risk within the sector will end up with the consumer by one route or another, except in circumstances where some third party, such as government, is willing to cover them.

What is important is that the sector's structure, regulation and contracts should allow the risks to be managed as efficiently as possible. This means that where risks can be reduced and controlled by good management, this should be reflected in the incentive structures built into the commercial arrangements.

For the irreducible elements of risk which can be deemed to be outside the control of any of the actors (eg oil prices), either investors will charge a premium on cost of capital,, the cost of which will pass through to consumers, or a regulated pass through of costs will allow a lower cost of capital to be charged because the consumer. There is a strong case (in earlier notes we quoted Green) that the latter approach is more efficient and will result in lower prices.

Q. Surely this means that we are back into an era of centralised decision taking where strategic decisions are no longer left to the private sector and the competitive market?

It is possible to argue that centralised decision taking is a necessary outcome of some of the problems identified elsewhere, and that a complex non-fossil generation mix requires the imposition of constraints on what proportions of plant are technically compatible. However it is also possible to argue that most of the decisions, particularly on the quantity of plant to build, can be pushed back to the major electricity suppliers, who choose how much to contract from the central agency, under the "contracted capacity" approach.

One important purpose in proposing an agency model is to allow the introduction of *some* elements of central coordination into investment and operation – the third being to improve regulatory certainty for investors. However this remains consistent with incentives for innovation, and competitive market disciplines, across the main activities of proposing technical innovation in generation, choice and construction of plant, and maintenance and operations. The precise balance between a "low carbon policy" and a "market" approach can be debated, but it will need to be struck under any structure for the sector, including the current one.

Q. This could prejudice the market position of fossil plant, leading to its early closure and hence loss of security through inadequate medium term capacity?

As an assumption this makes presumptions about how markets would operate in a transitional period. However it is no different in principle from the risks already identified for fossil plant dependent on revenue earned in relatively short periods of operation and hence "price spikes".

This concern also assumes no responsibility is assumed by suppliers for capacity adequacy.

A simple solution however would be just to allow the agency to contract with existing plant. Existing fossil generators not covered by a vertically integrated structure would welcome the opportunity to secure such contracts. If the central agency were responsible for ensuring an adequate amount of capacity, it would have every incentive to contract medium term for fossil peaking plant. Such generators however might be in competition both with each other and with new alternatives.

Q. A central buyer would get tied in with well established technology options and this would have the effect of shutting down innovation and new technologies. It would also operate against the interests of decentralised options?

It could be argued that this a far greater danger within the existing structure, with the development of a potentially cosy oligopoly of the Big 6. By contrast a central agency would almost certainly have to demonstrate to its regulatory body or sponsoring ministry that it ***was*** exploring all the most economic options. The central agency would not own significant generation assets, so it would not have a direct vested interest, and prima facie its duties to secure the most efficient and economic means of meeting security and low carbon obligations should give it an incentive to welcome innovation.

An interesting question is what responsibility a central agency might have for promoting decentralised options. It would certainly have no remit to constrain them and at a minimum would have to take account of their impact on "system" demand and load factor. However there is no reason in principle why it should not encourage decentralised solutions when these can be shown to be cost effective.

There are also much wider questions of how the power sector would develop in order to accommodate a very large aggregate transport load, which might nevertheless manifest itself as a very large number of "decentralised" units engaged for example in battery charging. The central agency might need to play a major role in shaping load patterns, for example through tariffs.

In all these areas it is likely that the agency would need to take account of the advice emanating from DECC and the Committee on Climate Change.

Q. A Central Agency will undervalue the diversity of alternative sources of capacity?

The opposite is more likely to be true, given that the agency would necessarily have an important role in ensuring that the balance of capacity types is technically compatible with maintaining supply. Even if we just take wind as an example, it is widely recognised that the wind capacity contribution, or “wind load factor”, can only be optimised if there is adequate geographical diversity in the siting of wind turbines. This is unlikely to happen without some element of central direction or coordination.

Q. What role would an agency in relation to developing the transition from oil and gas in the transport sector?

It is hard to analyse exactly how this might develop, since it is hard to predict how alternative low carbon technologies for the sector might develop. However the current front-runner, electric batteries, and its associated markets, would clearly need to be developed in a way that was consistent with the technical capability of the power sector to supply battery charging load at the right time and in the right places. Moreover the transport load, whether through batteries or through hydrogen, provides a potential solution to the problems of intermittent and inflexible generation, with a large controllable load providing the equivalent of storage or interruptibility.

This implies a significant role for the agency and/or suppliers in strategic consideration of this large load development together with alternative options for low carbon generation, and in development of the right commercial arrangements, notably tariffs, to make the system operate efficiently.

Q. A central agency would undermine the benefits obtained from supply competition?

There are two answers to this. The first is to question the extent of the benefit deriving from supply competition per se. Most of the benefits deriving from the 1990 privatisation can be attributed to the switch from coal, the advent of cheap gas, large efficiency gains in transmission and distribution driven by effective monopoly regulation, and the operation of private sector and competitive market disciplines in the generation sector, rather than from competition in supply.

Theoretical benefits of supply competition to consumers are largely undermined by supplier reliance on consumer inertia, and a lack of transparency. Green[11] inter alia has suggested that in principle supply competition delivers higher prices than a system based on contracts. The main drivers of cost efficiency in the sector will remain, in the form of competition and contractual incentives governing the construction and operation of generating plant and in distribution – the “wires business”.

[11] *Retail Competition and Electricity Contracts,* Green , December 2003

The second response is simply to observe that supply competition could and should continue, but it would be forced to focus on the activities of supply, providing better customer service, and some additional services such as advice on energy efficiency.

Q. Surely central agencies tend to over forecast demand, and markets with decentralised decision taking will foster a more accurate match between supply and demand?

First there is no reason to assume this is the case, except insofar as a central agency may have incentives to provide adequate capacity that are better aligned with the relative social costs of under and over provision. This asymmetry is covered in the author's submission to the recent OFGEM consultation and elsewhere.[12]

Second, the agency would not have any regulatory or financial incentive to increase its asset base, since it would not an owner of plant. It would have an incentive to ensure adequacy, which does not apply to any party within the current market structures.

Third, one very plausible modus operandi for forecasting and planning requirements would simply be based on supplier companies, faced with a well defined obligation to ensure capacity adequacy, who would make their own forecasts and contract accordingly.

Q. Surely we should not waste effort on time-consuming changes to the institutional structure of the sector, particularly if this involves legislation?

This is a powerful argument although we should not forget that the 1990 reforms went from inception to delivery in less than two years – a vastly more complex undertaking.

However the key point of our analysis has consistently been that the key requirements – regulatory certainty, resolving the functionality issue of a wholesale market in a post-fossil power sector, and infrastructure coordination – will remain and will have to be resolved by the sector even without institutional change. Move to a central agency can therefore just be seen as a direction in which the sector will have to move, and this paper has suggested several options, not all of which need require major legislation.

We would also note that the change of the Grid from joint ownership to independence was achieved with very few problems. Moreover the post 1990 state of joint ownership implies that this type of structure has never been seen as fundamentally at odds with an overall competitive framework.

Q. This would be blocked in Brussels on single market, competition or other grounds?

Given the extent of liberalisation and genuinely competitive markets across the EU, it

---

[12] *Reforming Uk Electricity Markets. A Purchasing Agency For Power. How should OFGEM approach the issues of security and sustainability?* Rhys, Oxford Energy Forum, May 2010.

would be a profound irony if the UK, which has largely pioneered competitive structures in power, were to be forbidden to make essential adjustments to maintain a sensible competitive framework for its own industry.

In practice this would only be likely to be a problem under some of the more extreme versions of a central agency, with an absolute monopoly over generation and no provisions for third party access. This could easily be managed, in consultation with the EU if necessary, in designing an approach to implementing a preferred package of measures.

We should also bear in mind that other EU countries, if they have truly competitive markets, should in principle be facing very similar questions.

CONCLUSIONS

This paper began by highlighting a number of very serious problems in the achievement of a low carbon power sector, and hence ambitious overall carbon reduction targets, with policies based on an assumption of the status quo in electricity markets. These include technical inadequacies leading to market failure and policy measures for provision of the regulatory certainty that will be necessary to underpin the large scale investments required. They also involve arguments of increasing need for coordination, notably in relation to the introduction and operation of new generation technologies.

Moving beyond piecemeal market adjustments, a number of the options proposed for the reform of markets lead, directly or indirectly, towards the concept of a coordinating agency involved in strategic and purchasing decisions. This paper has identified some of the alternative forms such an agency might take, and how it might evolve, for example, as a consequence of a supplier obligation.

Such an approach does have the potential to deal with all the problems identified, including those of technical consistency with efficient operation and regulatory certainty for investment, without compromising to any significant degree the gains that have been made since 1990 as a result of competition, private initiatives and effective regulation.