

Dynamics of GB Electricity Generation Investment

Summary Report

July 2006



Dynamics of GB Generation Investment

Executive summary

The objective of the study is to ascertain likely trends in security of electricity supply, generation diversity and carbon dioxide emissions, and to consider the benefits and costs of possible new policies designed to address future concerns in these areas.

Through dynamic modelling of investment decisions under different scenarios, the future evolution of the generation capacity mix is projected assuming a 'Status Quo' energy policy. The analysis suggests that the annual energy margin over the next eight to ten years would trend slightly below current levels. However, the anticipated concentration of plant retirements required under the Large Combustion Plant Directive could result in a significant drop in the peak capacity margin from 2016. This is exacerbated by the increasing amounts of intermittent generation coming from wind and hence, the risk of unserved load increases significantly during the period 2016-2020 before new investment begins to reduce the capacity shortage. The analysis also highlights the possibility of reduced generation diversity, if retiring nuclear, coal and oil plant are replaced predominantly with combined cycle gas turbine (CCGT), thus increasing the reliance on imported gas. Conversely, a new wave of investment in coal plant - a possible outcome in some scenarios - could place the Government's carbon dioxide emissions targets in jeopardy.

The benefits and costs of four policy options (Capacity Obligation Certificates, Diversity Obligation Certificates, Nuclear Obligation Certificates and Government Tendering), designed to address some of the potential future concerns, were analysed in detail. The analysis indicates that none of these policy options alone can simultaneously provide benefits against all of the key metrics. Also, the spread in results across scenarios is greater than across the policy options. This suggests that external factors (mainly fuel prices) are likely to have a greater impact on the investment landscape than any of these policy options that have been designed to influence investment behaviour.

Whilst carbon allowance allocation policy is not designed to address security of supply concerns, this analysis illustrates that decisions on policy in these two areas should not be taken in isolation. With any intervention there is a risk of unintended consequences, and any policy would accordingly need to be carefully designed.

Assuming gas supplies remain secure, the analysis suggests that immediate intervention to enhance security of electricity supply is not necessarily required, and the market (both generation and demand sides) could be given some more time to see how it adjusts to the prospect of tightening supply margins and greater levels of generation intermittency in the next decade. However, decisions must be taken early enough to ensure a stable investment framework in which the market can operate effectively.

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Dynamics of GB Generation Investment

I Introduction

This paper summarises the results of analysis undertaken on behalf of the Department of Trade and Industry, focusing on the generation investment issues raised by the 2006 Energy Review. It accompanies a more detailed report entitled “Dynamics of GB Generation Investment: Detailed Analysis”.

The objective of the study is to ascertain likely trends in security of electricity supply, generation diversity and carbon dioxide emissions, and to consider the benefits and costs of possible new policies designed to address future concerns in these areas.

2 Issues facing investors

Since liberalisation in 1990, the market has been effective in bringing forward new investment in the GB generation sector in the form of combined cycle gas turbine (CCGT) plant. The first wave of investment in the early and mid-1990s came mainly from the Regional Electricity Companies, looking to diversify their sources of electricity away from the large incumbent generators, and supported by their franchise electricity supply businesses. The second wave in the late-1990s was in response to historically low gas prices, and was driven to a large degree by international, mainly US, energy trading companies. Since 2000, the spark spread has been significantly lower, initially because of falling wholesale electricity prices and subsequently because of rising gas prices.

Whilst the Renewables Obligation has led to significant interest in renewables projects, there have been few other large-scale new build investments during the past four years. Most investment activity has involved vertically integrated companies acquiring existing assets to cover their domestic and small commercial customer load, or coal stations investing in flue gas desulphurisation in order to maximise the benefits from the current economic attractiveness of coal.

Few suppliers are willing to support their large industrial and commercial load with physical assets due to the low profit margins and lack of market share certainty beyond the latest contracting rounds. The risk is asymmetric. If the supplier invests in new capacity and wholesale prices fall it may make a significant loss; conversely, if it does not invest and wholesale prices rise, it can avoid the losses from being in a short position by declining to renew the contracts of a few large customers. The preferred risk management strategy is to hedge supply contracts with purchases from baseload generators as the customers are signed (or fix their contract price), and thus locking in the margin with limited risk.

With no clear price advantage of new build over existing plant (and with small consumer portfolios already largely hedged), companies must make their investment decisions on the anticipation of future generation scarcity. The tightening supply margin would need to push prices sufficiently above existing plant's short run marginal costs to cover the capital costs of a new unit. The uncertainty surrounding future revenues and costs is large, thus increasing required rates of return.

Key risks include:

- Commodity price volatility
- Lack of liquidity in longer term electricity markets
- Uncertainty surrounding the most economic choice for new investment
- Uncertainty surrounding investment costs of technologies untested in the UK
- Uncertainty surrounding future demand levels
- Uncertainty surrounding the future of the EU Emissions Trading Scheme, and carbon allowance allocation policy
- Uncertainty around future Government energy policy.

Even in the case of combined cycle gas turbines (CCGTs) which are afforded some degree of inherent price risk hedge by high correlations between wholesale electricity and gas prices, there is load factor risk, as there may be times of the year when demand can be met more cheaply by other fuels.

Load factor risk is the key challenge facing potential investors in peaking capacity. Although cheaper to build than CCGTs, open cycle gas peaking plants have about two thirds of the efficiency. This means that their operating cost is well above that of a CCGT. Hence, in general they will only be able to compete when all the available CCGT (and probably coal) capacity is running. There is uncertainty whether electricity prices would be above their short run marginal costs for sufficient time each year to earn a return on the investment. For so long as buyers for longer term peak cover are not evident, there may be few options for managing the risk around such assets.

Against this investment landscape, a key question is whether sufficient investment in new build will be forthcoming to meet growing demand and replace retiring nuclear plant and older coal and oil plant which will need to close under the terms of the Large Combustion Plant Directive (LCPD) before 2016. Another question is if new investment is concentrated in CCGTs, could a gas-dominated generation sector, even one with comfortable capacity margins, be exposed to problems associated with future gas supply difficulties? And finally, if the economics of coal continue to improve, what challenges will the UK face in meeting its carbon dioxide emissions targets?

3 Analysis approach

The first objective of the analysis was to determine what levels and types of new investment might be expected between 2006 and 2020 under the Status Quo (or Business As Usual) Case, with no additional financial support for generators outside of the existing Renewables Obligations.

The second objective was to analyse the benefits and costs of policy options designed to address some of the potential issues surrounding security of supply, generation diversity and carbon dioxide emissions identified in the Status Quo modelling.

Understanding uncertainty and how this affects the decisions of different market participants (vertically integrated companies, nuclear generators, independent power producers, project developers, oil majors) forms a key part of the modelling approach. Macro level uncertainty is captured using scenario analysis, whereas the uncertainties facing different investors are addressed by estimating risk premia through stochastic modelling of key risk factors (commodity prices, construction and operating costs, carbon allowance allocations etc.). These risk premia will vary by investor type, generation technology and scenario.

The investment decisions are modelled independently from the year-on-year simulation of the market. This avoids the risk of assuming perfect foresight in how new plant is built, and reflects the reality of decision making in an uncertain environment. The model assumes that expectations of future price are influenced by both recent history and projections of future fuel prices and capacity margins. The planning and construction cycles are simulated as the model rolls forward through time. If an investor’s expectation of future prices exceeds the level required to meet its risk-adjusted rate of return, the plant moves into a planning phase. The decision to build may be placed on hold if the economics of the investment deteriorate during this period. However, once construction starts, the investor is committed, regardless of how its price expectations then evolve. Hence, the modelling does not assume that all investments turn out profitable.

The Status Quo (the case with no policy interventions) is modelled across five different illustrative scenarios or states of the world. Subsequently, the analysis is rerun for each scenario under the four policy options. The costs and benefits of each of the policy options are measured against the Status Quo.

The five different scenarios analysed are summarised in Table I below.

Table I Scenarios modelled

Scenario	Description
Restrained Demand	A world where demand (served from the transmission grid) is steady or falls through a combination of effective energy efficiency measures and growth in embedded generation. Lifetimes of nuclear plant (other than Magnox) are extended and availability increases from current levels.
Steady Growth	A steadily increasing capacity gap resulting from continued demand growth. A world of relatively high gas prices coupled with improving clean coal economics, and relatively loose post-2012 carbon emissions constraints. Further consolidation amongst energy companies.
Third Dash for Gas	Falling gas prices leading to competition to build next generation of CCGT plant to fill anticipated capacity gap.
Volatile World	A world characterised by high and volatile fuel prices, especially gas, coupled with strong environmental concerns and hence tight post-2012 carbon emissions constraints. Further market consolidation as some players exit the market.
DTI Base Case ¹	An update to Restrained Demand using some DTI modelling assumptions on fuel prices (with are higher), and electricity demand (which is higher long-term).

¹ This scenario is labelled the DTI Base Case because it uses DTI central modelling assumptions on future fuel price and electricity demand. It does not necessarily represent the DTI’s view of the most likely scenario outcome.

4 The Status Quo

Investment choices

Investment under the Status Quo case is driven by investors' expectations of future returns in the market. The choice of technology is driven by the relativity of fuel and carbon prices, and by evolving investment costs and risks. Depending on the scenario, new build over the next ten years is typically dominated by either CCGTs or clean coal (advanced super-critical). In one scenario, Steady Growth, where the risk adjusted levelised costs are similar, both technologies feature in the new build profile.

In three of the five scenarios, new nuclear is economic in its own right without financial support². If the necessary planning and licensing hurdles are addressed, the first new nuclear plant is projected to become operational in 2019. Carbon capture and storage (sequestration) is only economic in one of the five scenarios (Volatile World), which features carbon prices (EUAs) in excess of 50 €/tCO₂ after Phase II EU ETS ends in 2012. The results on sequestration are sensitive to the investment and operating costs (and potential revenues from enhanced oil recovery³) around which there are currently much uncertainty.

The continuation of the Renewables Obligation leads to high levels of investment in wind, initially on-shore and then off-shore, in all scenarios. Eventually this is constrained by available sites. In four of the five scenarios, the resulting renewables shortfall leads to significant investment in new biomass plant.

Plant retirements are also influenced by the underlying economics of the different scenarios. Another major influence is the Large Combustion Plant Directive which has the potential to lead to a bunching of plant closures in the run up to 2015, resulting in the potential security of supply concerns discussed below. Further extensions to the lives of the AGR nuclear plant are possible. These decisions will be driven by the level of forward baseload electricity prices, and subject to clearance from health and safety authorities.

Security of supply

Two measures of supply margin are used in the analysis: the annual energy margin, which is the percentage excess available annual generation as a percentage of annual demand; and, the peak capacity margin which is the percentage excess capacity available during peak demand as a percentage of the peak demand⁴.

The modelling suggests that supply margins will drop from historical levels. In 2005, the annual energy margin was approximately 35%. In four of the five scenarios, annual energy margins fall to the range of 20-30%. However, in the Volatile World scenario, the annual energy margin drops as low as 10% by 2018 before recovering somewhat.

In itself, a small decline in the annual energy margin may not be significant, though it could indicate reduced resilience against sustained fuel supply problems. What happens to the peak capacity margin is potentially more noteworthy. Figure 1 plots the peak capacity margin and the

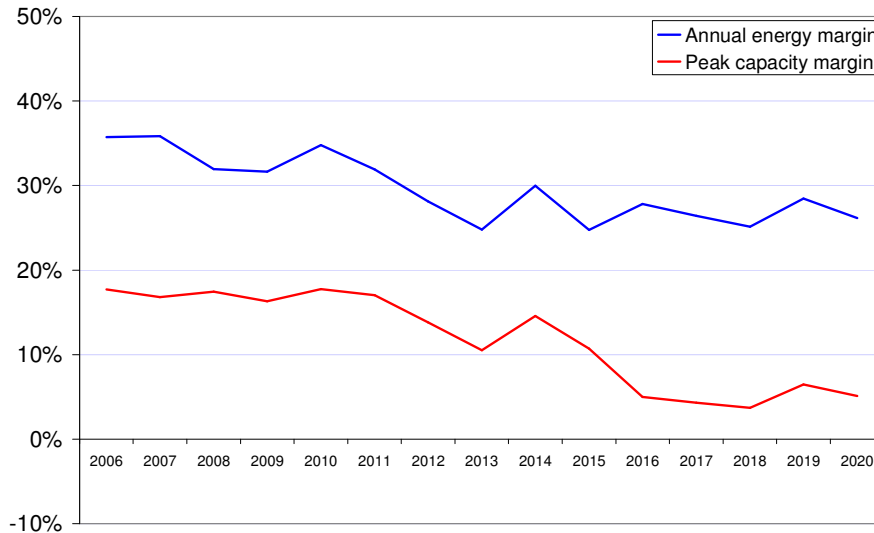
² A 40 year economic lifetime is assumed for nuclear plant. The economics of nuclear would look less favourable if investors were basing their investment cases over shorter periods.

³ Revenues from enhanced oil recovery are not considered in the analysis.

⁴The plant capacities have been de-rated to reflect the average plant non-availability during peak demand. This de-rating becomes increasingly important as the proportion of intermittent generation increases.

annual energy margin for one of the scenarios, the DTI Base Case. There is a notable divergence of the peak capacity margin from the annual energy margin from 2016 onwards. The (de-rated) peak capacity margin falls as low as 4%, compared to historic levels of around 15%. In one scenario, Volatile World, this margin actually becomes negative, which would suggest some unserved load even under average conditions.

Figure 1 Supply margins – DTI Base Case scenario



This divergence between the annual energy margin and peak capacity margin is caused by the LCPD. In its absence, a more gradual retirement schedule might be expected with new baseload entry pushing existing plant up the merit order to lower load factors before eventual closure. Under these conditions, the annual energy margin and peak capacity margin would largely track in parallel.

Under LCPD, coal and oil plant in particular have the choice between meeting specific environmental criteria, or “opting-out”. Where a plant opts out, it must operate for no more than 20,000 hours after 31 December 2007 and close by 31 December 2015. An opted-out plant may, however, re-open by fitting high specification flue-gas desulphurisation (FGD) as well as selective catalytic reduction (SCR), in which case it can operate without load factor limit. We have assumed that in most scenarios, the cost of this double investment will be difficult to justify for most opted-out plant.

The opted-out plant in Great Britain affected by the LCPD amounts to some 8.1 GW of coal fired capacity and 3.2 GW of oil fired capacity⁵. The 20,000 hour limit corresponds to a load factor of 28.5% if the plant is used evenly over the 8 years⁶ (though in practice the available load factor will be lower still because if one unit is operating, it counts against the permitted hours of all the units sharing the same stack).

It is unclear whether the opted-out stations will seek to spread their available 20,000 hours evenly over the eight year period, or whether they will wish, subject to environmental constraints, to utilise their hours more quickly. On the basis of an even utilisation, the

⁵ This excludes capacity that is currently mothballed and unlikely to become operational again before 2016.

⁶ Based on current economics, this load factor limit places a constraint on the coal plant, but not the oil plant whose expected load factor would be considerably less than 28.5%.

maximum that the opted-out plant can contribute to the annual energy margin is constrained at 28.5%, whilst, forced outages permitting, they are able to contribute fully to the peak capacity margin, and hence the much larger impact on the peak capacity margin resulting from their closure.

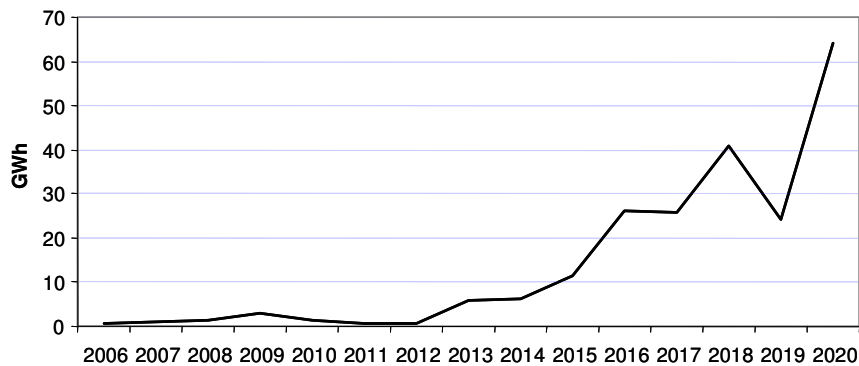
Viewed from an investor’s perspective, the LCPD-related closures create an opportunity for new plant equivalent to around 3.5 GW of new baseload capacity. The result of replacing 11.3 GW of LCPD opted-out plant with 3.5 GW of new baseload capacity would be to reduce peak capacity availability by nearly 8 GW.

It is important to note that we have assumed that all of the opted-in plant will be able to continue generating without significant load factor restrictions after 2016. This category includes some 20 GW of plant, of which 19 GW has fitted, or will fit, FGD. The LCPD will require this plant to reduce NO_x emissions by some 60% in 2016, which at present means the fitting of SCR. We have assumed that this will be done for all 20 GW of affected plant.

The impact of falling peak capacity margins may be exacerbated by the growing amounts of intermittent wind generation in the capacity mix. With an average peak availability of 30%, 1 GW of wind capacity is assumed to contribute 300 MW to the peak capacity margin and a roughly equivalent average capacity to the annual energy margin. However, whereas an equivalent 300 MW thermal plant can be assumed to be approximately 95% reliable at the peak, there is a greater risk of non-availability from the wind plant.

This risk can best be explored by stochastic modelling of plant availability and demand. Figure 2 illustrates that whilst under average conditions all demand would be met in the DTI Base Case scenario, there is an increasing risk of unserved load after 2015⁷. Averaged over 500 simulations the expected unserved load reaches 64 GWh in 2020. (In the Volatile World scenario this figure is as high as 6 TWh in 2018.) These figures would increase significantly if availability of wind plant was assumed to be correlated or if there was a risk of gas supply problems. For comparison, the average annual unserved load resulting from transmission outages in according to the National Grid was 900 MWh in 2003/04 and 888 MWh in 2004/05⁸, out of a total of approximately 360 TWh.

Figure 2 Expected unserved load under the DTI Base Case



This increasing risk of unserved load may not necessarily lead to physical blackouts, depending on how the market reacts to the associated increase in level and volatility of peak prices.

⁷ The calculation shown here assumes no correlation between plant availabilities and hence may under-estimate the risk. Correlation in plant availabilities is assumed in valuing diversity for the net cost/benefit analysis.

⁸ This does not include losses associated with outages on individual distribution networks.

Explicit investment in peak capacity would address this issue but may not be forthcoming for the reasons that we described above. Another possibility is greater demand side response, whereby large industrial and commercial customers are no longer prepared to pay an increasing premium for guaranteed continuous supply in a more volatile market, and accept greater degrees of interruption in their supply contracts. The precedents set by transmission ‘triad avoidance’ and interruptible gas contracts demonstrate that large consumers are prepared to shift load to reduce their energy bills (though it may be easier to use substitute fuels in the case of gas than electricity). Contracting further in advance to secure supply (individually or within buyers’ consortia) may also help to promote additional investment from generators and lessen the risk of unserved load.

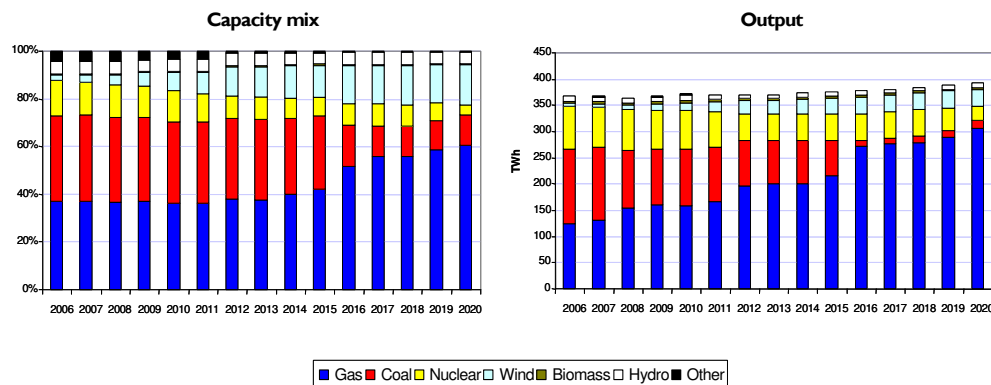
Generation diversity

Since liberalisation of the market in 1990, virtually all private investment in new large scale non-renewable plant build has been in CCGTs. This has seen the share of gas in the generation mix rising from virtually zero in 1990 to around 39% in 2005. The combination of favourable economics, relatively low investment costs and manageable risks has made CCGTs the technology of choice.

Recent rising gas costs have made the economics of gas less favourable, helping to explain the hiatus of new build over the last four years. However, gas still enjoys advantages over other technologies due to its low investment costs and construction risks. Furthermore, the current high degree of correlation between gas and electricity prices offers an inherent hedge against the commodity price risks. This reduces the risk premia attached to CCGTs relative to new coal plant, making it more attractive to investors even when the straight economics of the different technologies are close.

In three of the five scenarios, non-renewables build is dominated by CCGTs⁹. In the Restrained Demand scenario for example, the share of gas in the capacity mix increases to 69% by 2020, and contributes 78% of all generation in that year. The growth of gas is illustrated in this scenario in Figure 3.

Figure 3 Capacity mix and output by plant type, Restrained Demand scenario



Such high dependence on gas would mean any problems surrounding future gas security of supply could have a substantial knock-on impact on electricity. The ability of some CCGTs to

⁹ The modelling does not take into account the possibility that companies may choose to self-diversify as a risk management tool. This could lessen the concentration of CCGT generation.

switch to generate on distillate at peak, and the availability of any unutilised non-gas fired capacity to generate during a longer duration gas supply constraint, would help to mitigate this risk to an extent.

Carbon dioxide emissions

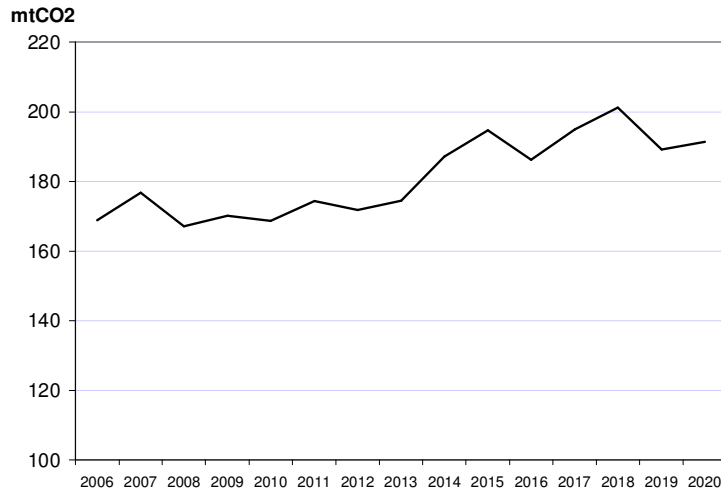
Rising demand and nuclear retirements during the period 2006-2020 place upward pressure on carbon dioxide emissions. Some of the growth is offset by enhanced energy savings measures (in two of the scenarios) and strong investment in renewables¹⁰.

Large scale low carbon electricity generation technologies, principally new nuclear and carbon sequestration, do not make a significant impact prior to 2020 but may provide longer term benefits in reducing carbon emissions from the generation sector.

In the period to 2020, the key driver of carbon emissions will be the relative prices of gas, coal and carbon coupled with carbon allowance allocation policy.

In the three scenarios that favour new gas build, carbon dioxide emissions reduce from current levels. However, under the Steady Growth scenario, where new build is dominated by clean coal, carbon dioxide emissions rise steadily, peaking at over 200 mtCO₂ by 2019. This growth is illustrated in Figure 4.

Figure 4 Carbon dioxide emissions, Steady Growth scenario



In the Volatile World scenario, emissions rise initially but then reduce once new nuclear and carbon sequestration plant become operational.

¹⁰ In general, renewables capacity tracks just below the Renewables Obligation target in the modelling.

5 Policy options considered

5.1 Policy considerations

The Status Quo modelling identified potential future issues surrounding security of supply, generation diversity and carbon dioxide emissions. Four policy options were designed that could potentially address these issues. These are:

- **Capacity Obligation Certificates:** A mechanism designed to accelerate investment in new capacity.
- **Diversity Obligation Certificates (DOCs):** A mechanism designed to bring on stream new capacity other than CCGTs or renewables.
- **Nuclear obligation certificates (NOCs):** A mechanism designed to incentivise new nuclear plant build.
- **Tendering:** Government or Transmission System Operator tenders for construction of new plant that can promote security of supply and generation diversity.

The parameters for each policy option were designed against a specific scenario, but then the policy and associated parameters were held constant across all five scenarios to demonstrate how the policy might perform under different market circumstances. Below, we describe the impact of each policy option on one specific scenario (the full set of results can be seen in the accompanying detailed report). The final cost/benefit analysis encompasses the results across all five scenarios.

In addition to these four policy options, a number of other factors important for investment decision making were recognised. Two of these were speeding up the planning process for new technologies and improved information on future demand levels. These issues may be addressed in the absence of, or in conjunction with, any of the four policy options considered. The issues surrounding future carbon policy (and certainty surrounding it) are also recognised as very important to investment decisions. The impacts of different carbon policies were analysed as sensitivities and are discussed below.

5.2 Capacity Obligation Certificates

The Capacity Obligation Certificate is designed to stimulate investment in new baseload plant and targets an annual energy margin of 35%, consistent with historic levels. It would work in a similar way to the existing Renewables Obligation; suppliers would be required to buy Capacity Obligation Certificates in proportion to their customers' annual demand or pay a buy-out price, the proceeds of which are distributed to certificate holders in proportion to their holdings.

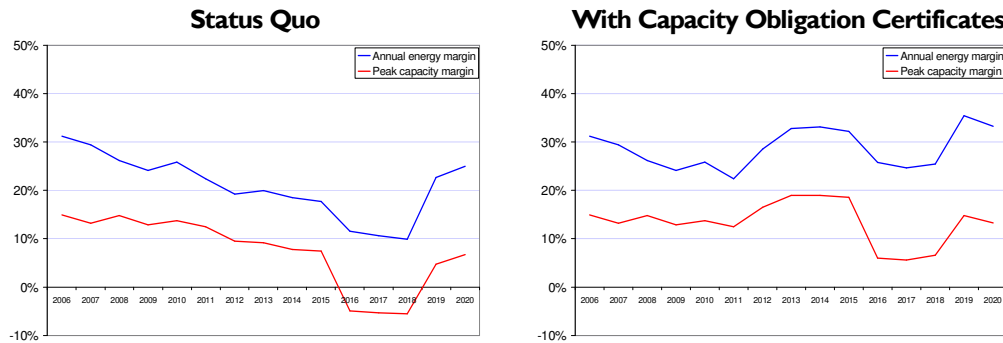
Newly built plant would qualify for these certificates, based on their annual availability. Eligibility for each plant would cut off after ten years of operation ensuring that the scheme continues to stimulate new investment.

The Capacity Obligation Certificate, as designed here, differs from a traditional capacity payment mechanism in that it only rewards new plant and does not explicitly target peak availability. However, many permutations of the scheme are possible.

Figure 5 illustrates the impact of the Capacity Obligation Certificates on the annual energy margin and peak capacity margin in the Volatile World scenario, the worst scenario from a security of supply perspective. It shows that the scheme is effective in halting the decline of the

annual energy margin. It also correspondingly improves the peak capacity margin, although the post-LCPD drop is still present (since there is no explicit reward for peak availability under this scheme).

Figure 5 Supply margins with and without Capacity Obligation Certificates, Volatile World scenario



The policy also improves the supply margins in the other scenarios, although there is evidence that (at least with these parameters) it can lead to over-investment and subsequent crashes in cases where strong build of CCGTs was taking place anyway.

Without reward for existing plant, a side effect of the Capacity Obligation Certificates is earlier closure of some plant, thus weakening their benefit. In stimulating the replacement of old plant for new, the policy generally leads to lower carbon dioxide emissions due to the improving average efficiency of the system, and frequently the replacement of existing coal plant with new gas. The downside of this is even greater dependence on gas, in the scenarios that favour new CCGT build.

The policy generally increases generation costs and costs to consumers. The modelling shows the price of the certificates generally in the range of £12/MWh to £14/MWh, tracking just above the buy-out price set at £12/MWh¹¹. This translates to a direct cost to consumers of around £4-5/MWh. However, Capacity Obligation Certificates place downward pressure on wholesale prices due to the greater level of plant availability and the lowering of average generation costs associated with the newer plant. The net cost to consumers is typically around £2/MWh over the period 2006-2020 (although there may be significant variations between scenarios).

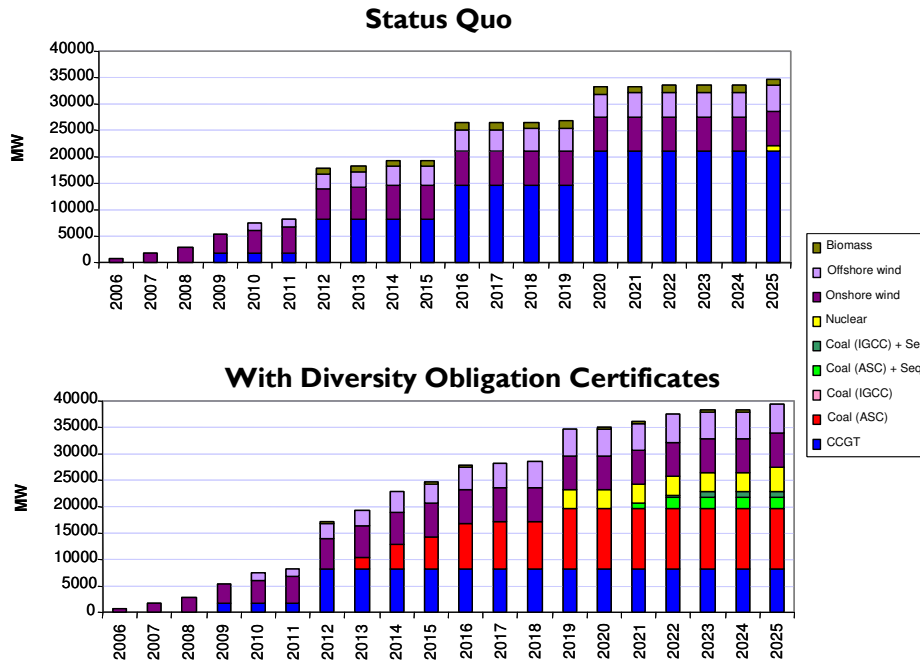
5.3 Diversity Obligation Certificates

The objective of Diversity Obligation Certificates is to stimulate investment in non-CCGT technologies to reduce the future reliance on gas in the generation sector. Again, this policy has been designed around a certificate scheme with a target of 10% of generation to come from new non-CCGT, non-renewables sources by 2009, rising to 25% by 2020. Renewables were excluded from these certificates because they receive separate support under the RO.

¹¹ These are quoted as MW of available capacity in each hour rather than electricity. The total obligation cost per annum is calculated assuming baseload operation of the plant. The £12/MWh buy-out price was identified by the modelling as the optimal level to stimulate new investment to the target level without leading to over-investment.

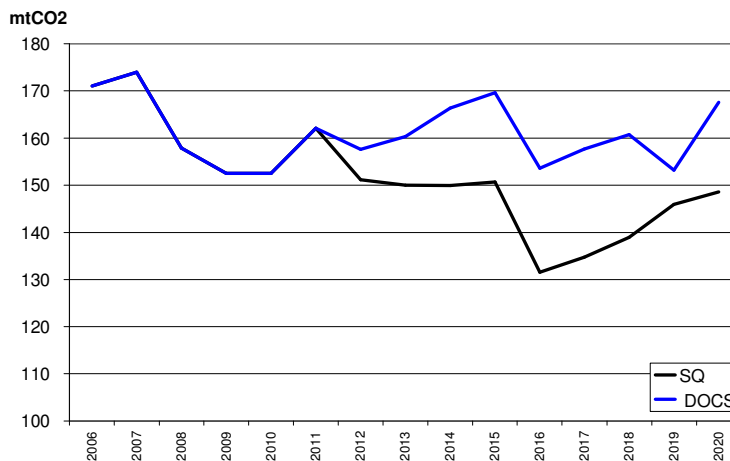
Figure 6 shows the impact of the policy in shifting new investment from gas to coal, and latterly to nuclear and carbon sequestration, on the Third Dash for Gas scenario.

Figure 6 New build with and without Diversity Obligation Certificates, Third Dash for Gas scenario



The downside of this policy is that it typically increases carbon dioxide emissions as seen in Figure 7. Growth is curbed once the new nuclear and sequestration plant become operational.

Figure 7 Carbon dioxide emissions with and without Diversity Obligation Certificates (DOCs), Third Dash for Gas scenario



The price of Diversity Obligation Certificates varies significantly across the scenarios. In scenarios where non-CCGT build is favoured anyway, the price of the certificates falls quickly.

In these cases, the effect of the policy is similar to the Capacity Obligation Certificates in stimulating new build of the most economic technologies (thus providing a benefit to security of supply). In the scenarios that favour CCGT build, the price of the certificates rises until coal plant become economic. Typically Diversity Obligation Certificates cost consumers in the range of £0-4/MWh over the period 2006-2020.

5.4 Nuclear Obligation Certificates

The Nuclear Obligation Certificates are intended to stimulate new nuclear build, and have been designed in the analysis exactly the same as Diversity Obligation Certificates with only nuclear qualifying. The long lead times of nuclear make this policy difficult to design, and some degree of support may be required during the construction phases. (Plant only qualify for Diversity Obligation Certificates once they become operational.)

The analysis suggests that this policy could stimulate new nuclear build although it is economic in three of the five scenarios anyway. However, since the study period only covers 2006-2020, the full costs and benefits of new nuclear fall outside the main analysis. The lead time of new nuclear plant means that they could not be operational to address the projected tightening of supply margins after 2015.

5.5 Tendering

The Tendering policy option is designed to address directly perceived shortfalls in future supply margins. The Transmission System Operator¹² (TSO) tenders for the construction of new baseload capacity of a specific technology. The lowest cost bidder is awarded the contract to build and operate the plant. The choice of technology may reflect additional government objectives around diversity or reduced carbon dioxide emissions. The TSO would auction the tolling rights to this capacity, once operational, to the highest bidder on an annual or multi-annual basis. Losses or profits from the tendered capacity would then be charged or reimbursed to customers through transmission charging.

The analysis suggests that the effect of tendering for capacity is to deter private investment. Only when all private investment is displaced can tendering for baseload capacity be an effective method of increasing supply margins. Thus, it would have a detrimental effect on competition in the market which would likely to lead to increased costs for consumers. Furthermore, underlying generation costs generally increase since typically the technology choices are not the most economic. This effect is especially pronounced if the cost of capital is assessed at a commercial rate (on the grounds that Government sponsored investment displaces commercial investment and should be priced on an opportunity cost basis rather than a low “Government” rate). The one significant benefit of tendering is the ability to control the generation mix, with potential benefits for diversity and lower carbon dioxide emissions.

Some of the difficulties in tendering can be addressed by limiting the tender to peaking capacity. This is addressed as a policy option sensitivity below.

¹² National Grid Company

6 Cost/benefit analysis

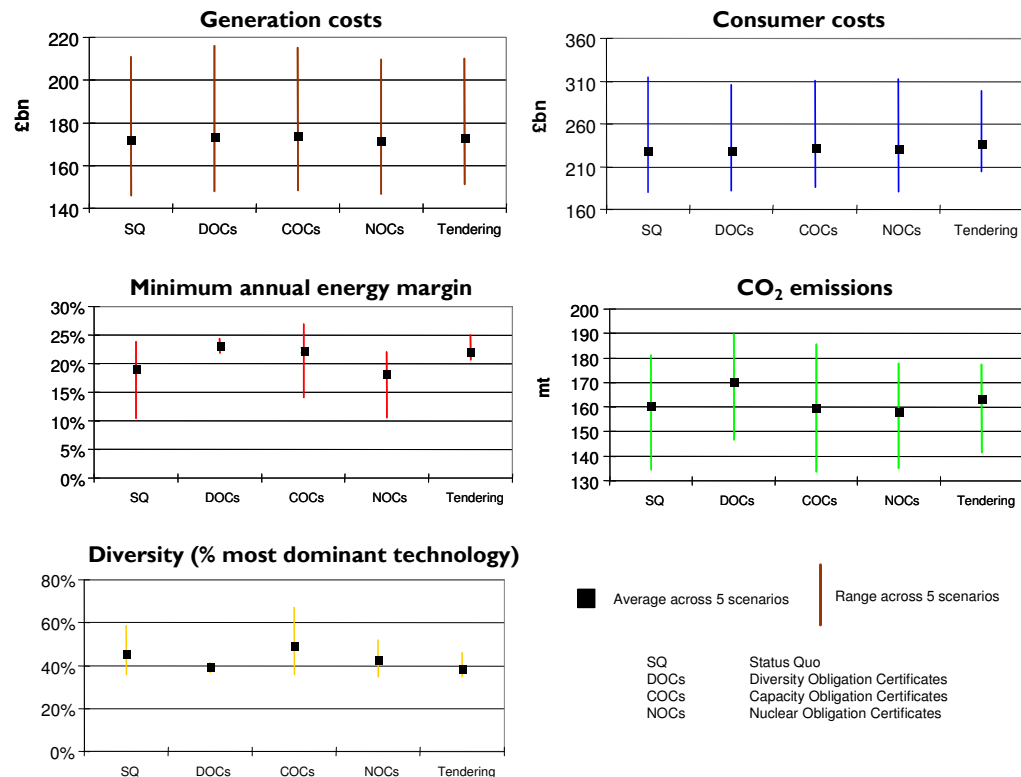
Table 2 summarises the key metrics against which the Status Quo and policy options are evaluated.

Table 2 Key metrics

Metric	Definition
Total generation costs	The net present value of the total costs of generation (2006-2020), including variable generation costs, annual fixed costs and annualised capital costs.
Total consumer costs	The net present value of total costs to consumers (2006-2020), including the cost of different policy options.
CO ₂ emissions	The average annual CO ₂ emissions (2006-2020) from the generation sector.
Supply margins	The minimum annual energy, and the minimum peak capacity margin (2006-2020).
Generation diversity	The percentage of the most dominant one and most dominant two technologies in the capacity mix by 2020.

Figure 8 summarises the results of the policy option analysis across the key metrics. The graphs show for each policy option the results averaged across the five scenarios (black square) and the range of results across the scenarios (coloured bars)¹³.

Figure 8 Summary metrics



¹³ No probability weighting is attached to the individual scenarios. Hence the averaging is for illustrative purposes and not a precise statistical measure.

The analysis illustrates that none of these policy options alone can simultaneously provide benefits against all of the key metrics. Interventions in general increase generation costs and costs to consumers. Capacity Obligation Certificates appear to improve the annual energy margin and are beneficial in reducing emissions. Diversity Obligation Certificates are also beneficial for security of supply and improve diversity, but at the costs of higher CO₂ emissions. Nuclear Obligation Certificates can decrease CO₂ emissions, but do not improve security of supply in the nearer term. Tendering for baseload capacity can be good for diversity and security of supply but displaces the market and is generally a costly solution.

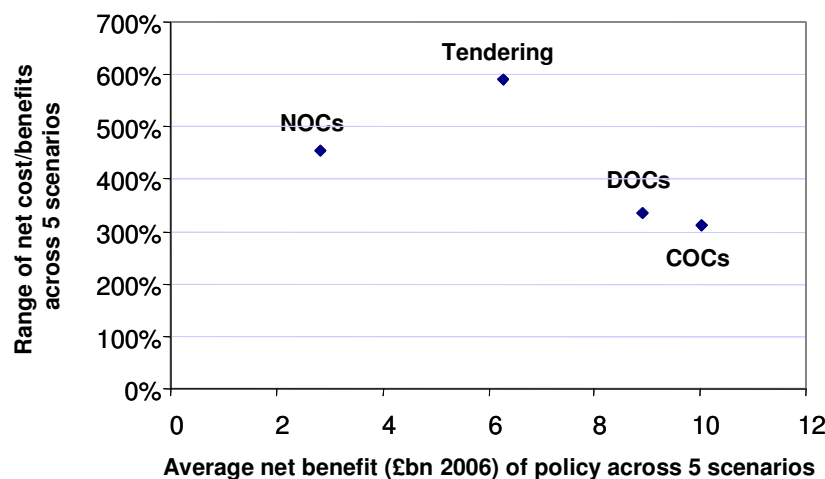
These results also illustrate that the spread in results across scenarios is greater than across policy options. This suggests that external factors (mainly fuel prices) are likely to have a greater impact on the investment landscape than any of these policy options that have been designed to influence investment behaviour.

For the final net cost/benefit analysis, the metrics are condensed into a unified financial measure¹⁴. To do this the following methodology is used:

- Defining the underlying costs as the total generation costs (rather than the consumer costs)
- Replacing the costs of the EUAs in the generation costs with a social cost for the carbon dioxide emissions
- Adding the cost of unserved load by estimating the volumes of unserved load at different levels of supply margins and applying a value of lost load
- Adding in the increased risk of unserved load due to correlated gas plant outages and wind plant availabilities

Figure 9 shows the average net benefit¹⁵ resulting from the cost/benefit analysis of the four policy options relative to the Status Quo against the spread in net cost/benefits across the five scenarios (a proxy for the risk of the policy option).

Figure 9 Average net benefit against range in outcomes¹⁶



¹⁴ On the basis of a net present value using a 3.5% real discount rate.

¹⁵ Based on the unified financial measure.

¹⁶ The range of net cost/benefits is calculated as the difference between the highest and lowest cases across the 5 scenarios and divided by the average.

These results are very sensitive to assumptions made on the social cost of carbon, the risk of gas supply problems, and the value of lost load (assumed to be £15,000/MWh). However, on this basis, all four policy options show a (small) net benefit relative to the Status Quo¹⁷. The breakdown of the average net benefits shown in Table 3 illustrate that this benefit is almost entirely derived from the improvements to security of supply. Diversity Obligation Certificates and Capacity Obligation Certificates offer the highest average benefits and appear lower risk than Nuclear Obligation Certificates or Tendering.

Table 3 Average net benefit against a range in outcomes

£bn (2006)	Diversity Obligation Certificates	Capacity Obligation Certificates	Nuclear Obligation Certificates	Tendering
Lower generation costs	-1.81	-2.56	0.24	-1.03
Lower carbon emissions	-0.20	0.15	-0.04	-0.24
Improved security of supply	10.91	12.44	2.61	7.55
Net benefit	8.90	10.03	2.81	6.28

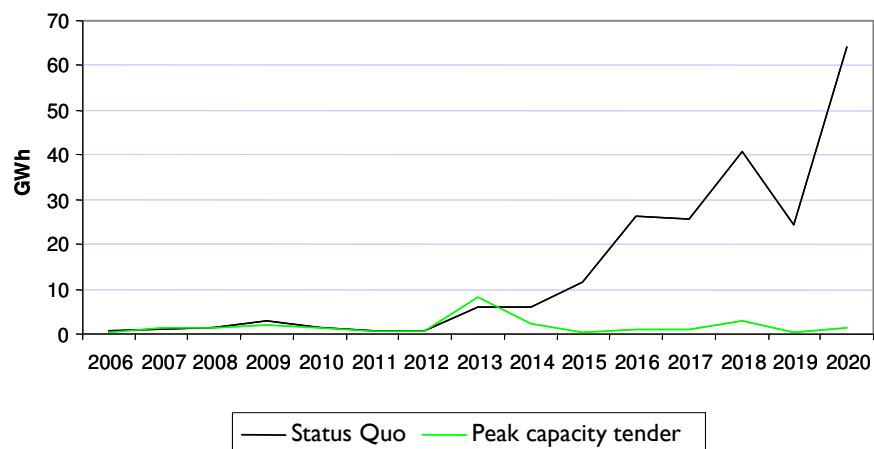
7 Policy option sensitivities

7.1 Tendering for peak capacity

A sensitivity to the Tendering policy option was considered, whereby the TSO tenders only for peaking capacity to target explicitly the falling peak capacity margin associated with the LCPD-related closures in 2015.

In this example, under the DTI Base Case, the TSO aims to maintain the peak capacity margin at or above 10%. This requires tendering for 4 GW of open-cycle gas turbine plant to become operational by 2016. Figure 10 demonstrates the impact that this additional peaking plant could have in reducing the risk of unserved load. Furthermore, the additional capacity should act to reduce the volatility of peak prices.

Figure 10 Unserved load with and without tendered peak capacity, DTI Base Case scenario



¹⁷ By quoting the results here on a net present value basis in 2006, the costs and benefits of the policy options are dampened since there is little variation in outcomes in the earlier years. Most of the impact of the policy options occurs after 2012. The time-profile of the benefits is illustrated in the detailed report.

Taking into account the investment costs, and the reduction in unserved load (but excluding operating costs and the revenues that the plant may earn), the value of lost load would need to be £2,250/MWh¹⁸ or greater to justify the investment on economic grounds. This is significantly less than the £15,000/MWh used to quantify the value of lost load in the cost/benefit analysis presented above.

Notwithstanding policy design issues, tendering for peak capacity would be less detrimental to the market in general since it should not significantly deter baseload investment. However, it might pre-empt any solution that the market could otherwise deliver in terms of investment in peaking plant, interruptible contracts or longer term contracting to guarantee supply continuity.

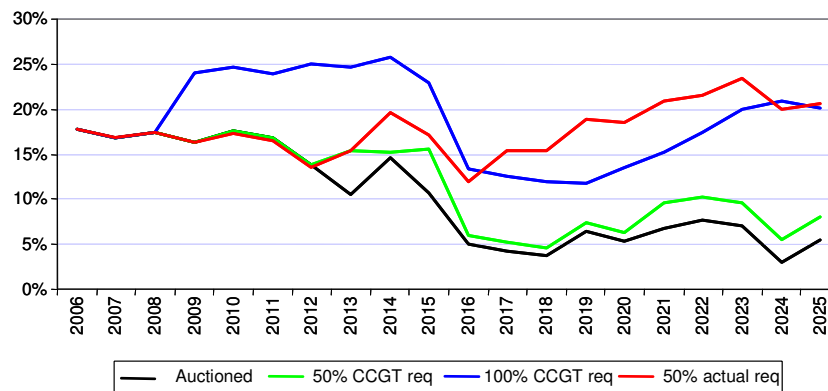
7.2 Carbon allowance allocation policy

In the main analysis, it is assumed that all carbon allowances are auctioned from the beginning of Phase II of the EU ETS¹⁹. A number of alternative allocation policies were also analysed. The results show a strong link between carbon allocation policy and supply margins. Free allocations act as a subsidy, stimulating new plant build and deferring the retirements of existing plant.

Figure I I compares peak capacity margins in the hypothetical situations where carbon allowances are allocated in Phases II, III and IV according to the following methodologies:

- Levelised across all thermal plant based on 50% requirements of a baseload CCGT
- Levelised across all thermal plant based on 100% requirements of a baseload CCGT
- Based on 50% of the benchmarked requirements of the plant by type based on baseload operation.

Figure I I Peak capacity margins under different carbon allocation policies, DTI Base Case scenario



Under the 100% CCGT requirements and 50% benchmarked requirements cases, the peak capacity margin does not fall below 12%.

¹⁸ This is based on the Government's costs of capital. If an 'opportunity' based cost of capital was used reflecting commercial rates, this figure would be £3000/MWh.

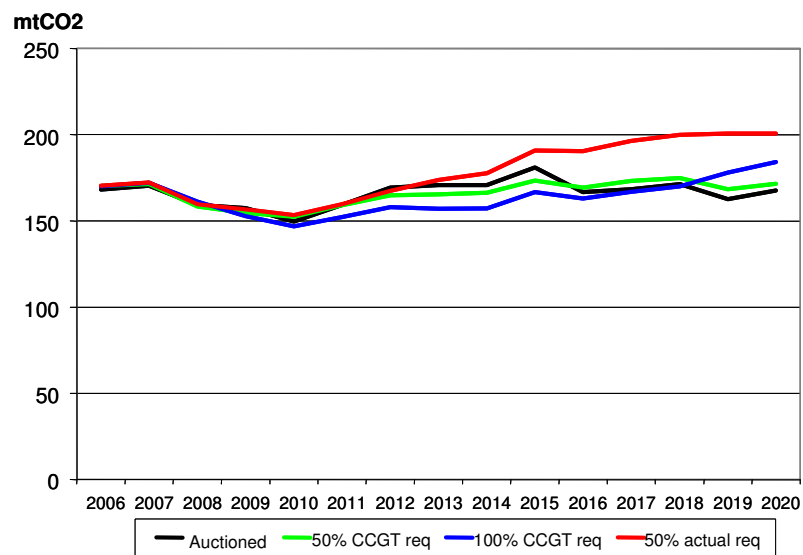
¹⁹ This assumption was made in order to isolate the impact of carbon allowance allocation policy from other policy options and does not represent Government intentions. The Directive provides for a maximum of 10% auctioning in Phase II.

Whilst carbon allowance allocation policy is not designed to address security of supply concerns, this analysis illustrates that decisions on policy in these two areas should not be taken in isolation.

It should be recognised that carbon allocations under EU ETS would only be effective in promoting investment in new capacity or major enhancements to existing plant, if it is possible to provide good visibility going forward of both allocation policy and carbon prices. This is not the case currently.

Figure 12 shows the impact of the different carbon allocation policies on carbon dioxide emissions. In the case of allocations based on 100% of CCGT requirements, carbon dioxide emissions are generally lower. This reflects the impact that this policy has in encouraging new higher efficiency plant onto the system. However, in the case of allocations based on 50% of actual requirements, new coal build is encouraged, offsetting the efficiency benefits and leading to higher carbon dioxide emissions.

Figure 12 CO₂ emissions under different carbon allocation policies, DTI Base Case scenario



8 Key conclusions

Status Quo

In the past, investment in the competitive market has been driven largely by fuel price differentials and there is no track record of scarcity of generation bringing forward investment in the UK market. If scarcity is the main driver, the analysis suggests that supply margins over the next eight to ten years would trend slightly below current levels. In the absence of any sustained gas supply problems, the risk of any unserved electricity load remains low.

However, the anticipated concentration of plant retirements coincident with the end of the Large Combustion Plant Directive could result in a significant drop in the peak capacity margin

from 2016. Combined with increasing amounts of intermittent generation coming from wind, this factor causes the risk of unserved load to increase significantly during the period 2016-2020 before new investment begins to reduce the capacity shortage. In such circumstances peak prices are likely to rise and become more volatile, but it is not clear that investors would be willing to invest to capitalise on this opportunity given the uncertainty of load factors and hence return on their investments. The demand side may, however, respond through greater prevalence of interruptible electricity supply contracts, or by moving to longer term supply contracts.

Diversity is quite likely to fall despite recent higher gas prices, since CCGT investment is still relatively attractive given its beneficial risk profile. There is much uncertainty surrounding future levels of CO₂ emissions, which will be strongly influenced by the relativities of coal, gas and carbon prices.

Policy options

The cost/benefit analysis of the policy options depends heavily on a number of assumptions, such as the underlying fuel prices, the social cost attached to carbon dioxide emissions, and the risk and value of lost load. Hence, it is difficult to draw definitive conclusions on the basis of the cost/benefit analysis alone. However, the analysis does allow certain conclusions to be drawn.

First, certificate based schemes to promote new capacity and/or diversity seem feasible, and have been proven to be effective in stimulating investment in the case of renewables. The costs to consumers could be fairly low, although there is an inherent risk of unintended consequences associated with any intervention, such as over-investment in the case of Capacity Obligation Certificates, or rising carbon dioxide emissions in the case of Diversity Obligation Certificates. Any such policy would need to be carefully designed and robust to changing external factors, in particular commodity prices.

Second, tendering for baseload capacity looks unattractive due to the negative impact on market competition, and ultimately costs to consumers. However, tendering may provide a solution for providing additional peaking capacity if the anticipated increasing risk of unserved load is deemed unacceptable.

The study period (2006-2020) is not sufficiently long to analyse fully the costs and benefits of a policy that promotes nuclear.

Timing

The analysis suggests that immediate intervention to enhance security of electricity supply is not necessarily required, and the market (both generation and demand sides) could be given more time to see how it adjusts to the prospect of tightening supply margins and greater levels of generation intermittency.

Without a sufficient market response to the changing environment, there is a materially higher risk than at present of involuntary demand reduction at peak times after 2015. Hence, any intervention (or decision not to intervene) must be implemented with sufficient time to create the stable investment landscape required to deliver new capacity before 2016, taking account of the lead times for various plant types in question.

Report authors

Duncan Sinclair - Redpoint Energy Ltd
duncan.sinclair@redpointenergy.com
0207 278 5955

Phil Grant – Redpoint Energy Ltd
phil.grant@redpointenergy.com
0207 278 5955

Rupert Steele - Energy Strategies Limited
rupert@energy-strategies.co.uk
07986 890547