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Addressing Market Power Concerns in the Electricity Wholesale Sector - Initial Policy Proposals

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Target audience: This document may be of particular interest to generators, suppliers, system operators, transmission owners, consumer groups and other interested parties.

Overview:

This consultation considers three broad approaches to tackling the issue of undue exploitation of market power in the GB wholesale electricity sector. Ofgem is concerned that the sector is vulnerable to such exploitation, both when there are constraints on the electricity transmission system and more generally at times of system tightness. Any undue exploitation of market power will make wholesale electricity more expensive and have a detrimental effect on the competitiveness of the wholesale market. The resultant costs are likely to be borne by consumers in terms of increased retail bills. In light of these concerns, we believe there is a case for developing proposals to address market power issues.

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Context

➔ This consultation forms part of our work to protect the interests of existing and future consumers, wherever appropriate through the promotion of effective competition in electricity markets. For consumers to benefit from liberalised markets, it is important that retail and wholesale markets function properly. In order to ensure the wholesale market operates effectively, Ofgem monitors its operation and the behaviour of its participants. Price spikes, which can exist or arise in wholesale electricity markets for short periods of time, in many cases will not indicate an underlying problem and could provide important signals for investment. But a generator which finds itself in a position of market power has the potential to harm competition and raise costs to consumers through certain behaviour. Ofgem needs to ensure that generators are not able to unduly exploit a position of market power, or that action is taken against any who do. This document consults on broad approaches to tackle these issues.

Associated Documents

Open letter on Managing Constraints on the GB Transmission System, 17/02/2009
http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/tar/Documents1/20090217Managing%20constraints.pdf

Closing letter on the Competition Act investigation into Scottish Power and Scottish and Southern Energy, 19/01/2009
http://www.ofgem.gov.uk/ABOUT%20US/ENFORCEMENT/Documents1/Competition%20Act%20investigation%20into%20ScottishPower%20and%20Scottish%20and%20Southern%20Energy.pdf

Energy Supply Probe - Initial Findings Report, October 2008 (Ref: 140/08)
http://www.ofgem.gov.uk/Markets/RetMkts/ensuppro/Documents1/Energy%20Supply%20Probe%20Report.pdf

Evaluation of the Competition Commission's past cases Act 2008 (pages 30-40)
http://www.competition-commission.org.uk/our_role/analysis/evaluation_report.pdf

Competition Commission Report - AES and British Energy: A report on references made under section 12 of the Electricity Act 1989
http://www.competition-commission.org.uk/rep_pub/reports/2001/453elec.htm

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Summary

Ofgem is concerned that the GB wholesale electricity sector is vulnerable to undue exploitation of market power, both when there are constraints on the electricity transmission system (which limit the amount of electricity that can flow between certain locations) and more generally at times of system tightness. This vulnerability has increased over the past few years and is likely to increase further due to a number of factors such as reduced availability of transmission capacity due to maintenance outages while new investment is undertaken, a significant increase in new renewable generation connecting to the system and environmental legislation limiting the use of certain generation capacity.

Any undue exploitation of market power will make wholesale electricity more expensive and have a detrimental effect on the competitiveness of the wholesale market. For example, there may be a negative impact on investment and new entry and a lack of confidence in the ability of prices to reflect market conditions which could lead to reduced liquidity. These factors could increase the price of wholesale electricity still further over time. The resultant costs of all these effects are likely to be borne by consumers in terms of increased retail bills.

In light of these concerns, we believe there is a case for developing proposals to address market power issues. This is given further weight by the difficulties encountered in applying Competition Act 1998 (CA98) legislation in the electricity wholesale context, where market power could be held by more than one party and is often intermittent in nature (and thus participants are unlikely to meet the CA98 dominance test). Also, such market power could often be exploitative in nature (excessive pricing) as opposed to exclusionary which relevant competition law precedent indicates can be harder to target using CA98 provisions. However, undue exploitation of market power could potentially still result in very high costs to consumers.

This consultation therefore considers three broad approaches to tackling this issue, which we welcome feedback on from stakeholders: changes to existing market arrangements; changes to existing assets and/or ownership of assets; and specific mechanisms for addressing market power concerns.

There are several changes to existing market arrangements which might impact on the extent of any market power that may arise and the potential for its undue exploitation. One option would be to improve alignment between the incentives of the System Operator (SO) and Transmission Owners (TOs) with respect to minimising the frequency and severity of transmission constraints. There are also a number of changes to other market arrangements that could potentially mitigate market power concerns. However, some of these proposals would only target market power issues relating to transmission constraints and none of them are likely to sufficiently address all of the concerns identified.

Changes to existing assets and/or ownership of assets could be considered, for example to require divestment (and/or sale of output under contract) by generators in areas where market power is thought to be present. Such changes could only arise as a result of a Market Investigation Reference (MIR) to the Competition Commission (CC) or primary legislation. However, our current view is that they are

also unlikely to be able to address all relevant concerns sufficiently and other remedies are likely to be more effective.

Specific mechanisms for addressing market power concerns could be considered. A Market Power Licence Condition (MPLC) on generators could be introduced to strengthen Ofgem's powers to carry out *ex-post* (i.e. after the event) investigations of generator behaviour and impose fines or other sanctions if participants were found to be exploiting unduly a position of market power. Such a licence condition could be narrowly drafted to deal with specific market power concerns, e.g. those related to transmission constraints. This would reduce the risk of uncertainty to generators about what is or is not unduly exploitative behaviour. However, this would need to be weighed up against the potential risk of some undue exploitation falling outside of the condition, thereby undermining its purpose and leaving a significant risk of increased costs to consumers. Consideration could therefore be given to reducing the risk of uncertainty to generators in the event of implementing a more broadly drafted licence condition (e.g. by clear enforcement guidelines, an appeal mechanism allowing for challenges to decisions taken under this licence condition and/or a review mechanism which would require Ofgem to review the appropriateness of retaining the licence condition from time to time).

Ofgem proposed a licence condition targeted at tackling market abuse in 2000. The CC subsequently upheld an appeal against its introduction. However, in its decision report the CC envisaged the possibility of the Secretary of State introducing new licence conditions if market power concerns proved to be a continuing problem under the market arrangements that were about to be implemented (known as NETA - the New Electricity Trading Arrangements): "*If, in the light of experience, such manipulation proves to be a significant problem under NETA and cannot be satisfactorily dealt with by rule modification, it will be open to the Secretary of State to consider using his powers under the Utilities Act to introduce new licence conditions to address the problem.*" In January 2008, the CC published a review of its decision on Ofgem's proposals that concluded: "*the CC's decision not to support the introduction of the MALC* [Market Abuse Licence Condition] *in 2001 seems well-justified by subsequent market developments in Great Britain. Equally, however, Ofgem's view that such powers can be necessary in some circumstances also seems to be supported by subsequent developments overseas*."

Another specific mechanism that could be used is some form of *ex-ante* (i.e. before the event) framework for controlling market power (as is commonly used in the US, e.g. in New York and New England). This could involve a screening mechanism to identify specific regions and/or time periods where market power was likely to be present, followed by a regulatory mechanism to cap prices by reference to a cost benchmark or an average of recent Balancing Mechanism (BM) bids and offers. This approach may provide greater certainty to market participants than an *ex-post* investigation under licence powers, but (similar to a narrowly drafted licence condition) there is a risk that it may not be sufficiently flexible to deal with all market power issues that could arise, that it may introduce other significant issues, e.g. detrimental effects on investment incentives, and that it would involve significant set up costs.

Although further alignment of SO and TO incentives and/or other changes to market arrangements may alleviate the problem to some extent, there appears to be only three credible approaches that could deal with the concerns at this time and protect existing and future consumers: a licence condition, price capping or some form of divestment.

Our current preferred mechanism would be a new licence condition on generators (potentially combined with consideration of further changes to market arrangements). We are also consulting on whether there could be appropriate ways to reduce the risk of uncertainty to generators from the introduction of such a condition, e.g. by clear enforcement guidelines, an appeal mechanism and/or a compulsory review by Ofgem. However, we have not ruled out any of the options in this consultation document and welcome feedback on all of the proposals, along with others that stakeholders may wish to bring forward at this stage. Following consideration of the consultation responses, Ofgem will look to issue a final proposals document on our preferred approach to tackling market power concerns by the end of the summer.

1. Introduction

Chapter summary

This chapter describes the physical and economic characteristics that may currently make wholesale electricity markets vulnerable to the undue exploitation of market power, and the context for current market power concerns in GB. We summarise policy developments that are already in train which could help to address some of these issues, and set out our rationale for further action.

Question box

Question 1: Do you agree with our analysis of market power concerns in the GB wholesale electricity sector?
Question 2: To what extent should further policy intervention be progressed or are there alternative approaches that can be adopted for dealing with the concerns?

Background

1.1. The potential for undue exploitation of market power in the electricity generation and wholesale sector has been an issue of concern to regulators since electricity markets first began to be deregulated in the 1980s. Economists and policy makers have noted that certain characteristics of electricity as a commodity, such as limited storability, a lack of available substitutes, very low short-run elasticity of demand, and (at times) the existence of constraints on the electricity transmission system[1] , currently make electricity markets particularly susceptible to the potential undue exploitation of market power by generators.

1.2. This market power may often be transient or intermittent in nature, but because of the limited scope for demand-side adjustment to short-term price changes it can result in very high costs to consumers and/or competitors during periods when it is unduly exploited. In other words, the lack of price elasticity in electricity markets means that the demand curve in the very near term is almost vertical - the vast majority of consumers are likely to continue to consume at the same level irrespective of the prices in the near term. This also reflect a limitations in current metering technology and settlement rules whereby not all customers will be in a position to change their behaviour in response to price signals nor would most currently have an incentive to do so. Furthermore, the System Operator (SO) must keep the system in balance on a second-by-second basis, which means that it is often buying power on behalf of customers/suppliers over a very short time horizon where no effective demand side response is feasible.

1 Referred to in this document as "constraints", these limit the amount of electricity that can flow between certain locations. See Appendix 3 for further information.

1.3. Some of the particular characteristics of electricity identified may not persist forever. Fundamental change such as the future roll out of smart metering (and associated "smart" tariffs) and progress on improved economics of storage of energy may mean that consumers could become more price sensitive and responsive (i.e. could make the demand curve much less inelastic) in the future. However, such change would need to be accompanied by significant reform of balancing and settlement arrangements to facilitate demand-side adjustment to short-term price changes and thereby keep market power in check.

1.4. On the supply side, market power may also be exacerbated because to alleviate such market power would require new generation investment at a specific location. Such a limitation could act as a barrier to entry. This, combined with the current shortage of available transmission capacity relative to energy capacity rights sold to generators[2] and the long lead times associated with expansion of the transmission network to accommodate new generation, means that market power may not be eroded over time (and certainly not in the short to medium term) through increased competition to the same extent as would occur in other markets.

1.5. Ofgem is not concerned with price spikes that are a consequence of underlying market conditions which are necessarily a feature of properly functioning markets[3]. Indeed, price spikes that reflect genuine scarcity play an important role in delivering security of supply. Without price spikes, providers of peak supply that run for very few hours each year may be unable to cover their fixed costs and earn a sufficient return[4], making it necessary for these generators to price above short-run marginal cost. Therefore, price spikes at times of overall shortage can be a necessary and efficient market response, which provide important signals for generation investment. However, there are situations in which price spikes can be the result of undue exploitation of market power. Such situations may include when the price spikes:

- differ unduly between times in which market demand and costs are similar; and/or
- are due to non-economic dispatch decisions (when considered over the long term and that cannot be explained by legitimate technical non-

[2] As discussed below, this issue arose as a consequence of the decision taken at the time of BETTA (British Electricity Trading and Transmission Arrangements) implementation, in the light of assumptions about the development of competition and the anticipated level of constraints costs. This decision introduced a principle that no user should be provided a later connection date or any greater access restrictions in the transition to BETTA than they had signed up to pre-BETTA.
[3] Throughout the document, for ease of reference, we refer to concerns about price spikes, but we are equally concerned about prices being artificially suppressed as a result of undue exploitation of market power.
[4] Baseload investors may also require price spikes since the infra-marginal rents earned, the difference between the cost of the marginal supply and their own short run costs, may be insufficient to meet the required return on equity.

availability) which could only be profitable to the generator concerned if they possess market power[5].

1.6. Under the current BETTA market design, such situations are particularly (although not exclusively) likely to arise in the context of constraints on the GB transmission system, which narrow the scope of the market thus increasing the market power of generators located in constrained areas. If price spikes due to market power are specific to a constrained location there is likely to be increased barriers to entry (since to respond to the price signal entry would have to be at the specific location) and no possible corresponding demand side response since prices faced by the demand side of the market do not currently incorporate a locational signal.

1.7. In other words, price spikes that are a consequence of underlying scarcity are a necessary feature of properly functioning markets and will encourage suppliers to contract in advance thereby sending appropriate signals for generation investment. This means that such market power should be kept in check through competition (provided the market is not unduly concentrated). However, under the current market design suppliers are not required to balance their portfolios by location (or by exact timing, i.e. second-by-second) and will not contract at this level of granularity. Any market power in relation to the supply of related products is unlikely therefore to be kept in check through competition and could be subject to undue exploitation.

1.8. We would welcome consultees' views on the distinction between price spikes which could be a necessary and efficient market response to provide important signals for generation investment and prices spikes which could be the result of undue exploitation of market power.

Context of current market power concerns in GB

1.9. Ofgem is concerned that the GB wholesale electricity market is increasingly vulnerable to undue exploitation of market power. A number of factors are currently likely to be exacerbating the scope for such undue exploitation, such as the current shortage of transmission capacity relative to the transmission entry rights sold to generators, the reduced availability of transmission capacity as a result of outages related to the investment programme to upgrade capacity, a significant increase in new renewable generation connecting to the system, much of which is located behind existing constraints, and environmental legislation limiting the use of certain types of generation capacity. As mentioned above, whilst there could be technological changes (combined with changes to balancing and settlement arrangements) which could reduce this in the long term, the factors exacerbating the scope are likely to

[5] Examples of non-economic dispatch decisions are when plant is not dispatched despite significantly positive spreads (profit opportunities) in the market or when plant is dispatched despite significantly negative spreads in the market, and in each case there is no short term or long term cost justification for such decisions.

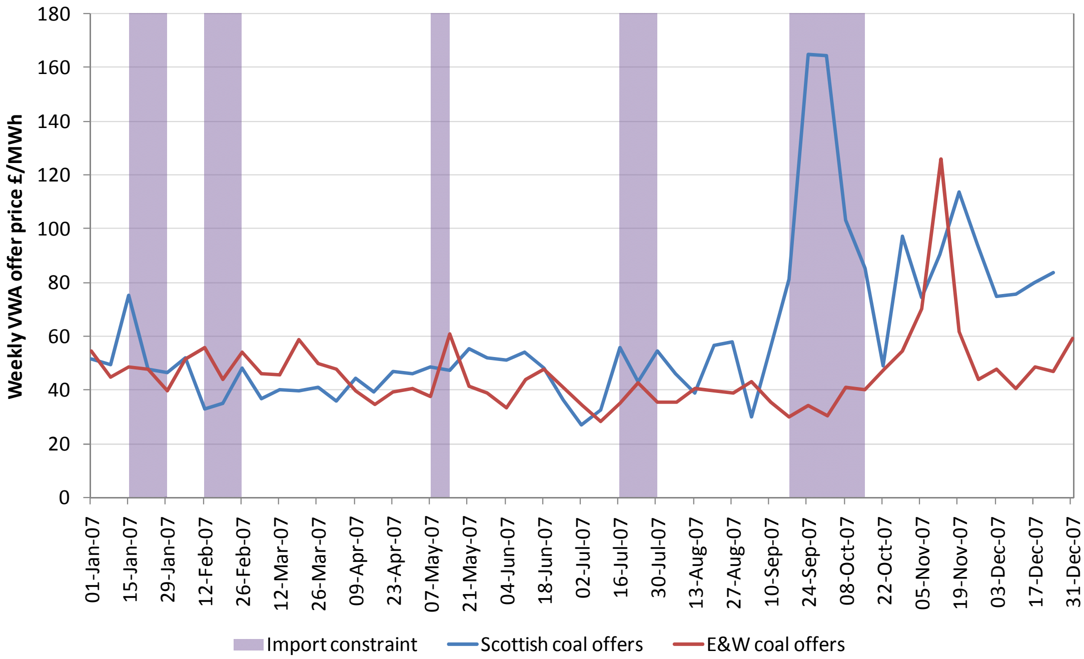
persist and potentially worsen in the short to medium term. This raises significant risks to consumers in terms of higher retail bills.

1.10. Furthermore, we are concerned that the potential for undue exploitation of market power, combined with a lack of effective enforcement powers for addressing it, can create issues with regard to competition in the market (with those able to exploit unduly market power having an advantage over their competitors) and uncertainty in the market, for example regarding the potential for large price spikes and unexpected increases in balancing costs. These factors may have a detrimental impact on investment and new entry, particularly for smaller players who have less ability to accurately forecast and hedge their positions. They are also likely to impact trading in the market, e.g. a lack of confidence in the ability of prices to reflect market conditions creates a reluctance to trade on the part of all players, and hence a lack of liquidity which exacerbates the difficulty in being able to hedge positions. These indirect impacts could further increase retail bills for consumers and increase the potential for undue exploitation of market power still further.

1.11. Although we consider that recent developments have heightened the need to review existing regulatory powers to deal with market power in electricity, there is a history of concerns in this area, which are summarised in Appendix 2. This includes our recent CA98 investigation into Scottish Power (SP) and Scottish & Southern Energy (SSE) launched in April 2008, following concerns raised by industry participants about possible exploitation of market power arising from constraints between England/Wales and Scotland[6]. The main concerns related to September/October 2007. The charts below illustrate the pricing patterns which led to these concerns being raised, and highlight why our investigation extended to other periods when constraints coincided with large bid/offer price differentials.

[6] Ofgem closed the investigation into SP and SSE on 19 January 2009, noting that the likelihood of making an infringement finding under CA98 was low, and that other actions were available which could be more effective in addressing the issues raised on a forward-looking basis.

Figure 1: Accepted BM[7] offers in constrained and non-constrained periods – Scottish coal plant versus E&W coal plant Jan-Dec 2007

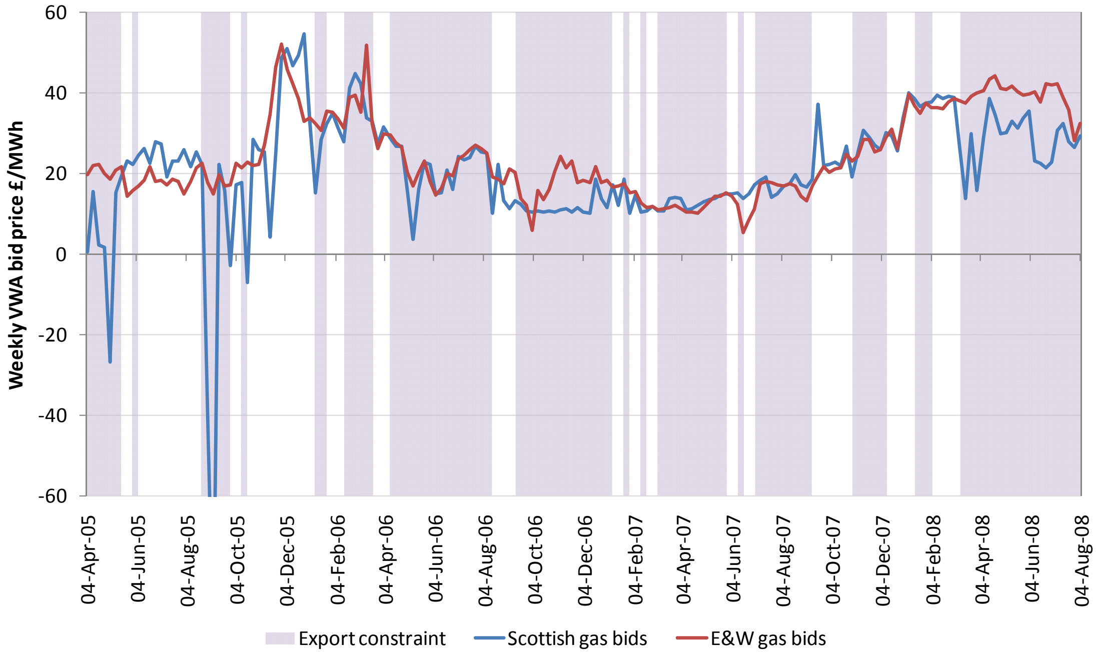


1.12. The above chart illustrates the large differential in accepted BM offer prices during the Sep/Oct 2007 import constraint period[8] as compared with other periods.

[7] Balancing Mechanism (BM) is the principle tool used by the SO to balance the electricity transmission system on a second by second basis.

[8] A constraint occurs where the transmission system is unable to transmit the power supplied onto the transmission system to the location where the demand for that power is situated. An export constraint is said to occur where total generation output in a given area exceeds the sum of demand plus transmission capacity to export from that area (i.e. excess supply over demand on one side of a constraint. On the other hand, an import constraint occurs where there is an excess demand over supply on one side of a constraint.

Figure 2: Accepted BM Bids in constrained and non-constrained periods, Scottish gas plant versus E&W gas plant April 2005-August 2008



Note: There were a number of accepted gas bids on 5th/6th Sept 2005 around -100£/MWh.

1.13. The above chart illustrates that export constraints from England/Wales and Scotland are present to some degree in most weeks. Large BM bid price differentials may be observed in a number of export constraint periods including September 2005 and summer 2008.

Potential materiality of market power concerns

1.14. Notwithstanding the difficulty of estimating the potential costs of market power concerns that may arise in future, looking at the rise in constraint costs now gives us cause for concern. As outlined in Table 1 below, annual constraint costs across GB have increased significantly since implementation of BETTA, from £84m in 2005/06 to a forecast outturn of £238m in 2008/09. National Grid (NG) has forecast that constraint costs will rise again in 2009/10.

1.15. Whilst increases in constraint costs can be partly explained by the trends in transmission availability and generation connections, it is also the case that the factors which have given rise to the existence of market power, and thus the potential for its undue exploitation have increased over the past few years. Applying observed pricing differentials[9] to forecast constraint volumes in 2008/09, in a worst case scenario the potential direct costs attributable to undue exploitation of market power could be as much as around £125m[10]. There may also be indirect impacts from any undue exploitation of market power on wholesale market prices, risk premia and competition. In the next few years the factors referred to above are likely to mean that the conditions for market power and the potential for its undue exploitation will increase still further.

1.16. The direct and indirect costs of any undue exploitation of market power are likely to be borne by GB consumers in terms of increased retail bills. In the longer run the impact on consumers would be greater if the undue exploitation of market power was to have the effect of deterring new entrants and reducing the competitiveness of the market.

Actions by NG to address constraint costs

1.17. Ofgem published an open letter to NG on 17 February 2009[11] (the "February 2009 open letter"), highlighting the rapid increase in both outturn and forecast constraint costs over the last two years and asking NG to conduct an urgent review of this issue. In the letter, we asked NG to consider whether changes to the existing commercial and charging arrangements are necessary before the next financial year (i.e., 1 April 2009) to more effectively manage the costs of constraints, and to ensure that any constraint costs are recovered on an equitable basis from consumers, suppliers and generators. Trends in GB constraint costs since 2005/06 are shown in Table 1 below.

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[9] Pricing differentials between generators in Scotland and England & Wales have been observed at times of constraint, both in the BM and contracts with NG (including commercial inter-trips).
[10] The worst case scenario considers the potential pricing impact of market power exploitation, comparing the observed price differentials for each type of constraint relieving action (BM, contracts, inter-trips) and multiplying by the volume of actions taken. Where pricing differentials may be partially explained by the relative cost of replacement actions, an appropriate adjustment is made. The worst case scenario does not explicitly take account of the cost of any undue exploitation of market power to exacerbate the volume of constraints.
[11] See:
http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/tar/Documents1/20090217Managing%20constraints.pdf

Table 1: Historical trends in constraint costs

	2005/06	2006/07	2007/08	2008/09*	2009/10*
Total constraint costs (£' million)	84	108	70	238	258
Total volume of actions in GB (GWh)				4,976	9,605
Average price of actions in GB (£/MWh)				47.8**	27.4
Constraint costs arising from Scottish actions (£'million)	70	80	42	210	209
Total volume of actions in Scotland (GWh)				4,430	3,539
Average price of actions in Scotland (£/MWh)				47.5**	60.0

Notes: *Latest forecast **While average prices appear to be similar in 2008/09, like-for-like comparison for each type of action taken (e.g. those taken in the BM) reveals that the prices are significantly higher in Scotland.
Source: http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/tar/Documents1/20090217Managing%20constraints.pdf

1.18. The February 2009 open letter noted that a significant proportion of the constraint costs arise as a result of available transmission capacity shortages relative to transmission entry capacity rights sold to generators in Scotland, and to a lesser extent England and Wales. It also noted that the level of available transmission capacity will be heavily influenced by transmission outages as part of the transmission investment the three TOs are making to increase network capacity. We highlighted that the capacity shortage issue arose as a consequence of the decision taken at the time of BETTA to introduce a principle that no user should be provided a later connection date or any greater access restrictions in the transition to BETTA than they had signed up to pre-BETTA[12].

1.19. In the February 2009 open letter, we noted that this decision was taken in the light of assumptions about the development of competition and anticipated level of constraints costs, but that recent experience of constraints costs imply the need to revisit those assumptions. It also noted that if and to the extent that market power issues could serve to increase the overall cost of resolving constraints in Scotland this would necessarily reinforce the need to take action to address constraint costs.

[12] Implemented through transitional licence condition SLC C18, applied to NGET, and consequential derogation (the "BETTA derogation"), issued to NGET and SPTL, from the requirement to comply with the GB SQSS planning criteria over circuits which form the boundary between England and Scotland (the Cheviot or 'B6' Boundary) until 2011/12, subject to a range of key conditions.

NG was encouraged to consider actions that could be taken to address both the volume and price of constraints, and also to assess whether current charging mechanisms for constraints are equitable and appropriate.

1.20. In response to Ofgem's letter, two proposals have now been raised by NG: a charging modification to introduce a locational element to Balancing Services Use of System (BSUoS) charges, in order to reflect the costs of resolving constraints back onto generators in constrained regions which are non-compliant with the Great Britain Security and Supply Standard (GBSQSS); and a Connection and Use of System Code (CUSC) modification to set administered prices for inter-trip contracts. NG is also giving further thought to other options, including mechanisms which could improve the incentives on TOs to minimise constraint costs for example by reducing the length of outages. Ofgem's views on such mechanisms are discussed in more detail in Chapter 2.

Other relevant policy developments

European framework for market abuse

1.21. In December 2007, the European Commission asked ERGEG, the European Regulators' Group for Electricity and Gas, and CESR, the Committee of European Securities Regulators, for advice on a range of issues relating to trading in electricity and gas. One of the questions asked was whether the Market Abuse Directive (2003/6/EC) was sufficient to address market integrity issues in the energy sector. The advice of ERGEG and CESR was published in October 2008[13] and concluded that the general Market Abuse Directive did not appear to address fully the situation in electricity and gas markets. It went on to state:

"CESR and ERGEG are of the view that the Commission should consider developing and evaluating proposals for a basic, tailor-made market abuse framework in the energy sector legislation for all electricity and gas products not covered by the Market Abuse Directive."

1.22. We understand that the Commission is currently considering how to take these matters forward and intends to hold a workshop this spring. It is possible that this will lead to legislative proposals. However, the timing and scope of such proposals (if any) remains uncertain. We consider that these developments provide some context for consideration of market abuse in the energy sector in GB.

[13] See: http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/CEER_ERGEG_PAPERS/Cross-Sectoral/2008/E08-FIS-07-04_%20MAD%20Advice.pdf

Changes to cash out arrangements

1.23. Cash-out charges are intended to reflect the costs of NG balancing the overall levels of electricity supply and demand in each period ("energy balancing costs") on behalf of market participants. Costs incurred in resolving "system" imbalances, including constraints, should be excluded from cash-out and recovered through BSUoS charges. However, the current cash-out arrangements do not perfectly separate energy and system balancing costs, and the costs of system actions can in some periods "pollute" cash-out prices[14].

1.24. Changes to the cash-out rules could therefore help to reduce the influence of system actions on cash-out prices. This would help to mitigate the impact of constraint-related market power issues on the wider wholesale market, since the increase in short-term prices observed on the APX during constrained periods is assumed to reflect participants' desire to avoid high cash-out prices. However, it would not change either the incentives or opportunities for the potential undue exploitation of market power by generators in the BM during periods when constraints are active.

1.25. Modification P217 will be implemented in November 2009[15]. Once implemented, NG will identify in advance an area in which a constraint is expected to arise. Accepted bids and offers from any power station in that area will automatically be excluded from the calculation of cash-out prices, on the basis that those actions will be taken for constraint (i.e. system) rather than energy balancing reasons. Actions will be reinstated into the cash-out calculation if more expensive energy actions have been taken in that period.

1.26. It is unlikely that all system actions will be identified and removed from cash-out under P217, but it should prevent circumstances such as those seen in September/October 2007 from re-occurring, where significant costs incurred in resolving constraints were incorporated into cash-out charges. As explained above, this does not change the reward to generators who are pricing to take advantage of the constraints (nor therefore change total direct costs to consumers), but it leads to a more efficient allocation of the costs, and should lead to more cost-reflective forward prices.

[14] See, for example, Ofgem's Impact Assessment of BSC Modification Proposals P211 and P212, http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=98&refer=Markets/WhlMkts/CompandEff/CashoutRev, for a discussion of the system pollution issue.
[15] See: http://www.elexon.co.uk/ChangeImplementation/modificationprocess/modificationdocumentation/modProposalView.aspx?propID=237 for details of P217.

Transmission Access Review

1.27. The Transmission Access Review (TAR) was undertaken jointly by Ofgem and the Department for Energy and Climate Change (DECC)[16]. It was initiated following publication of the Energy White Paper in May 2007. The TAR Final Report to the Secretary of State in June 2008 set out a number of both long-term and short-term measures which have the overall objective of facilitating the connection of new renewable and low carbon generation to the system. In response to the proposals for long term access reform set out in the TAR Final Report, a suite of modifications to the Connection and Use of System Code (CUSC) was raised by NG in April 2008 and these modifications have now either been submitted to Ofgem for approval or are in the process of being further developed by the industry. Broadly speaking, the CUSC proposals can be grouped into four broad models for transmission access reform:

- an 'Evolutionary Change' model, which would introduce more flexible and tradable transmission access products, with appropriate user commitment;
- a 'Connect and Manage' model, in which the right to access the system is driven primarily by the requirements of connecting generators;
- an 'Auctions' model in which long-term transmission capacity is allocated via auctions among generators; and
- a 'Capacity Pricing' model in which any application for long-term transmission access rights including volume, duration, load duration and buyback commitment will be accommodated and provided with fixed *ex-ante* prices reflective of the impact of such rights on the network investment and operation costs.

1.28. Whilst the main driver of the TAR reforms is to facilitate the achievement of the Government's renewable generation targets, the proposals could also bring forward the connection of new generation with more diverse ownership in Scotland and hence help reduce ownership concentration and therefore market power. Depending on the approach taken, the changes could also provide better signals for more targeted and efficient transmission investment in future which could further help to alleviate constraint-related problems.

1.29. However, accelerated connection of new generation and the associated increase in use of the transmission network, particularly in Scotland where the majority of prospective renewable projects are located, has the potential to exacerbate export constraints in the short to medium term if measures are not taken to address these issues. This issue was highlighted in the context of our assessment

[16] The Transmission Access Review was originally a joint project involving Ofgem and the Department for Business, Enterprise and Regulatory Reform (BERR). Following the formation of DECC and the transfer of functions from BERR to this new Department, the project is now a joint Ofgem and DECC project.

of CUSC Amendment Proposal CAP148[17], which proposes priority connection arrangements for new renewable or low carbon generation, by guaranteeing connection to the transmission system by a firm date, subject to completion of local works but without dependency on deep reinforcement works. The accelerated connection of such generation in turn increases the incidence and associated cost of constraints, and potentially increases the potential for undue exploitation of market power by generators in a unique position to relieve those constraints. Our analysis, with generator prices based on marginal costs and socialisation of constraint costs, suggests the impact on constraint costs may be of the order of £700m[18] in NPV terms, and a further £600m higher in the case that generators increase BM offers by 100% above marginal costs.

1.30. Our forthcoming assessment on the TAR-related CUSC proposals will be considering the impact on consumers from any increase in constraint costs alongside the potential benefits from more efficient allocation of capacity and increased investment.

1.31. In the longer term, the TAR reforms may address some of the factors which give rise to the opportunity to exploit market power unduly. However, they will not fully address our concerns.

1.32. NG has recently identified scope to advance the connection dates of 450MW of Scottish renewable generation seeking connection to network, based on the respective network owners' abilities to advance local network connection work and the generators' own willingness and ability to utilise earlier connection. In an open letter published on 19 March 2009 (the "March 2009 open letter") we set out the interim approach (until the successful implementation of enduring access arrangements) that we are minded to adopt to facilitate earlier connection of generation through derogations from the minimum requirements under the GB SQSS. We proposed that these arrangements would apply to the 450MW of Scottish renewable generation seeking connection to network, and any other generators in GB, provided that their local transmission works are complete and they are connected to the contiguous GB Transmission System.

1.33. In the March 2009 open letter we recognised that the downside of extending this principle is that it might give rise to higher constraints costs, for example, of up to £40m per annum for the initial 450MW identified by NG.

Rationale for further action

1.34. Ofgem welcomes NG's action in raising proposals to address the cost of constraints in GB, and we will be assessing and deciding on these proposals in due

[17] CAP148 Impact assessment and consultation, July 2008.
[18] Base case scenario with connection guaranteed within 4 years of the project gaining planning consents.

course in line with our statutory duties. We also consider that other policy developments that are currently in train, such as the implementation of recent changes to cash-out arrangements and the TAR proposals, could help to address the impact of constraint-related market power in the BETTA market.

1.35. However, given our wider concerns over the potential for undue exploitation of market power, both in the context of constraints (whether in Scotland or elsewhere in GB) and more generally, we believe there is a case for developing further proposals to address such issues. Our rationale for taking action in this area is given further weight by the following issues:

- difficulties in applying CA98 legislation in the wholesale electricity context, given that market power is often intermittent in nature and may be held by more than one generator at key times, which renders the task of establishing dominance and/or collective dominance under CA98 problematic. Also, such market power could often be exploitative in nature (excessive pricing) as opposed to exclusionary which relevant competition law precedent indicates can be harder to target using CA98 provisions;

- developments in the rest of Europe where wholesale market power has been recognised as an issue by the European Commission (in November 2008 - the Commission announced a decision to accept commitments from Eon following its investigation into withdrawal of capacity in the German wholesale market (COMP/39.388));

- developments in other jurisdictions, in particular:

  - the experience in California in 2000 and 2001, which demonstrated the severe consequences that can result from the undue exploitation of market power in wholesale electricity markets. While we do not anticipate problems of this scale emerging in GB, the California experience does reinforce the need for energy regulators to have appropriate tools for tackling such undue exploitative behaviour if such a situation should ever arise. In the light of events in California, the FERC introduced federal market behaviour rules in 2003 to supplement market power mitigation measures at the State and regional market level. Subsequent legislation in 2005 provided the FERC with specific anti-manipulation powers, superseding some of the market behaviour rules; and

  - the situation in the Nord Pool which has market conduct rules and ethical guidelines that inter alia prohibit “market manipulation” and “inside trading”. These rules are enforced by the exchange rather than a regulator, however, Nord Pool's position in the Nordic markets is such (i.e. day ahead spot market has a market share of nearly 70%) that participants cannot really circumvent them by trading outside the exchange[19];

- a likely increase in the incidence of constraints, both within Scotland and elsewhere in GB, due to new renewable generation coming on-stream and the on-going requirement for transmission outages to undertake necessary reinforcement works; and
- the impact of environmental legislation, such as the Large Combustion Plant Directive, which has led to greater uncertainty regarding when generation may be run, and which may create opportunities to unduly exploit market power.

Structure of the document

1.36. The remainder of this document sets out Ofgem's initial proposals for tackling market power concerns in the GB wholesale electricity sector. Chapter 2 discusses possible changes to existing market arrangements, including mechanisms to improve alignment of incentives between the SO and TOs, and changing BM pricing. In Chapter 3, we set out possible changes to existing assets and/or ownership of assets, including divestment of generation capacity and/or transmission ownership.

1.37. Chapter 4 covers specific mechanisms which could be used to address market power concerns, including a new licence condition on generators, and an ex-ante regulation framework similar to that applied in certain US markets. Chapter 5 considers potential mechanisms for implementation, including the possibility of a Market Investigation Reference (MIR) to the Competition Commission (CC) or seeking primary legislation. Finally, Chapter 6 sets out Ofgem's current thinking in relation to the proposals raised in this document, and discusses next steps.

1.38. Ofgem welcomes feedback on all of the proposals, along with others that stakeholders may wish to bring forward at this stage. Further details of how to respond can be found in Appendix 1.

[19] It should be noted that in GB, participants in the APX are subjected to a Code of Market Conduct regulated by the FSA, which also deals with market manipulation and inside trading issues.

2. Changes to existing market arrangements

Chapter summary

This chapter describes options that involve changes to the incentives on the SO and TOs, and/or changes to other market arrangements that could help to address market power issues in the GB wholesale electricity sector.

Question box

Question 1: To what extent to you think that changes to SO and TO incentives and/or changes to other market arrangements are likely to be effective in addressing the concerns discussed in Chapter 1?
Question 2: Are there any other changes to existing market arrangements that Ofgem should consider?

2.1. The NETA/BETTA arrangements have been in place now for close to eight years in England and Wales and four years in Scotland. Implementation of NETA is thought to have contributed to a decline in the potential to exploit unduly market power by comparison with the previous Pool arrangements. However, there are certain modifications to the current wholesale market design that could potentially help to mitigate on-going and new market power concerns in the electricity sector. We first explore several options which would improve the alignment of SO and TO incentives[20]. We then consider changes to other market arrangements. There are currently several proposals which have already been raised, such as administered pricing of inter-trips and locational BSUoS, which may mitigate market power concerns to some extent. Given our role in the modifications process, a detailed discussion of these lies outside the scope of this document.

Improved mechanisms to align SO and TO incentives

2.2. Concerns have been raised in the context of market power regarding whether the incentives on SO and TOs are sufficiently aligned. At present, the SO may request that a TO reschedules an outage in order to reduce the size or duration of a constraint, but they are under no obligation to do so[21]. If the TO agrees to this

[20] Changing incentives on the SO in balancing the system could also impact on the potential for undue exploitation of market power. We review these incentives from time to time and through this process consider the extent to which market power can be mitigated by the SO.
[21] Since Scottish transmission networks (SHETL and SPTL) are not owned or maintained by NG, the SO does not have the authority to require deferment of transmission outages within Scotland. Procedures for coordination and communication between the SO and the Scottish TOs are set out in the SO-TO code (STC).

request, the SO can reimburse them to cover some or all of the costs of doing so, e.g. costs of changing planned maintenance.

2.3. While structural options are discussed later in Chapter 3, initial thoughts on mechanisms that could potentially improve alignment between the incentives of the SO and TOs with respect to minimising the frequency and severity of constraints (and thereby reduce the associated risk of undue exploitation of market power) are discussed in more detail below.

Changes to the way in which the timing and duration of outages is determined

2.4. One potential option would be to make it mandatory for TOs to commit to fix the outage period that they have notified to the SO. A contributing factor to the magnitude of constraint volumes is that notified outages to the SO are not binding, so they can potentially overrun, or be started earlier or later than notified, which often results in additional costs to balance the system.

2.5. An alternative option may be to incentivise TOs to adjust their outage plans to help reduce constraint costs. There is already a provision within the existing licence for the SO to pay TOs for moving their outages, but the scope of this provision is quite narrow. In considering the best approach for developing this option, the mitigated constraint costs and the effect of moving the relevant planned outage would need to be considered in detail. However, this option would not incentivise TOs to be proactive in planning the timing of outages, nor the use of assets in a way that minimises constraints.

Cost-sharing arrangements for constraint costs across TOs

2.6. An alternative solution would be to design an incentive scheme that focuses TOs on reducing the number and length of outages. This could be specifically in relation to critical circuits with high constraint cost exposure. At present, constraint costs are borne solely by the SO who passes them through to generators and suppliers, but if these costs were also shared across TOs to some extent, this would incentivise them to plan outages and use of assets in such a way as to help minimise constraint costs, as they would share in the benefits of reduced constraints.

Considering ways in which SO could facilitate more investment in TO regions

2.7. A further option would be to look at the ways in which the SO is able to facilitate investment in TO regions. However, Ofgem’s current thinking is that this could be difficult given that investment on the transmission network is already underway and further opportunities may be limited.

2.8. We note that NG has indicated in its response to Ofgem's open letter on managing constraints that it is considering options for aligning SO and TO incentives and will be discussing these further with Ofgem. However, we would welcome feedback from other stakeholders at this stage on these options or any others that consultees wish to bring to our attention.

Changes to other market arrangements

2.9. There are a number of changes to other market arrangements that could play a role in helping to mitigate market power in addition to those proposals that are currently being considered (for example changes to pricing in the BM which is explored briefly below). However, such changes may not address all market power concerns, and would have wider impacts on the market. Hence, whilst any future decisions on market arrangements will take into consideration the impact on market power, the tackling of market power may not be the prime motivation for such changes.

Pricing in the BM

2.10. The introduction of Modification P217 in November 2009 may increase the transparency of pricing in the BM during periods of system constraints. Under the modification, NG will 'flag' those actions that it expects will be required to manage constraints. This will help timely monitoring of how offers and bids change in response to constraints.

2.11. It is possible that further changes to the market design surrounding the BM may improve transparency further. For example, under a cleared auction, rather than a pay-as-bid mechanism which is the current design, generators may be incentivised to bid and offer close to their marginal costs, rather than bid up based on their expectations of marginal price. This could make monitoring easier. However, there are also strong reasons why introducing marginal cleared pricing in the BM, without considering other design changes, would increase costs for consumers and therefore not be beneficial despite the greater transparency it affords. This is because the marginal (price-setting) bid or offer might reflect a specific locational or timing requirement, and not be representative of the bulk of the actions taken for that period and some generators could be over rewarded as a result.

2.12. At this stage, Ofgem has not fully explored the pros and cons of this proposal. However, we welcome any high level feedback and, depending on consultees responses, would consider issuing a detailed consultation on this option or any other change to market arrangements raised by consultees.

3. Changes to existing assets and/or ownership of assets

Chapter summary

This chapter describes options to address the underlying assets and/or ownership of assets that could allow for the undue exploitation of market power in the GB wholesale sector.

Question box

Question 1: To what extent do you think increased transmission investment is a feasible option and likely to effective in addressing the problem?
Question 2: To what extent do you think that the other asset related options discussed are likely to be effective in addressing the problem?
Question 3: Are there other asset-related remedies that Ofgem should consider?

3.1. Chapter 2 set out options to address market power concerns through changes to existing market arrangements to reduce the incentives to unduly exploit market power and/or make it easier to detect and monitor. However, it could be argued that a better approach would be to seek to address the underlying causes of the problem by tackling underlying asset issues that could create opportunities for the undue exploitation of market power. In the GB market, such issues may include:

- limited transmission capacity relative to generator demand for (and rights to) that capacity, which is currently a particular issue along the Anglo-Scottish border (Cheviot) and within Scotland;
- concentrated ownership of generation capacity (particularly flexible thermal plant) in constrained regions; and
- the structure of transmission ownership in GB, in particular the vertically integrated structure of the Scottish TOs and the split between the SO and TO roles.

This chapter outlines options to address each of the above issues in turn.

Limited transmission capacity

3.2. An obvious option for addressing the constraint related market power concerns arising from limited transmission capacity would be to increase transmission investment in GB, particularly along the Anglo-Scottish border and within Scotland where constraints are currently most prevalent. This could provide a robust long-term solution to the problem of constraint-related market power, although it would not address the current issues regarding the level of constraints nor would it address wider market power concerns that are unrelated to constraints.

3.3. However, a substantial investment programme to upgrade the Cheviot transmission boundary is already underway and given the severe congestion of transmission works associated with connecting new generation in Scotland and further downstream, the scope for accelerating already identified efficient transmission investment may currently be limited. The required increase in system outages to accommodate accelerated construction programmes may also make the problem worse in the short term, as evidenced during the summer 2008 works on the Cheviot boundary, which resulted in a sharp rise in constraint costs. Therefore "building our way out" of the problem is unlikely to be a viable solution to constraint-related market power in the short to medium term, although it could be beneficial in the longer term. Even in the long term, an efficient level of transmission investment, with optimum trade-off against constraint and other operational costs, would still not be constraint-free. Therefore, transmission investment would not, by itself, eradicate all constraint-related market power issues.

3.4. Reforms to the arrangements for allocating access rights to the transmission system may also address some of the factors which give rise to the opportunity to exploit unduly market power, however these initiatives will take time to deliver change. An alternative option in the short term is to make changes to the commercial and charging arrangements to more effectively manage the costs of constraints and to ensure that any constraints costs are recovered on an equitable basis. These issues are discussed in more detail in chapter 1 in the context of our recent open letter to NG on managing constraints costs and TAR.

Concentrated ownership of generation

3.5. Following the forced divestment of generation capacity in the 1990s, and new entry in the generation sector, the GB wholesale market is no longer considered to be highly concentrated particularly by comparison with many overseas jurisdictions. HHIs for the generation sector as a whole based on total capacity are currently around 1000, well below the OFT's guidelines for a highly concentrated market[22].

3.6. However, this measure may mask potentially significant concentrations in certain locations. For example, if the generation market is confined to Scotland (as may be the case when constraints are active along the Anglo-Scottish border), then concentration levels are considerably higher, with an HHI of around 3300. Moreover, concentration levels are even higher in terms of flexible plant that is capable of providing short-notice balancing power to NG. Between them SP and SSE currently own virtually all of the flexible generation plant (i.e. thermal, pumped storage and

[22] The Hirschman-Herfindahl Index (HHI) is a measure of market concentration. The HHI is calculated as the sum of the square of the market shares of each firm in the market.

hydro) in Scotland, and HHIs based on a Scottish market for balancing power are around 5,500[23], indicating a high degree of concentration.

Physical divestment

3.7. One option to address constraint related market power problems arising in the GB wholesale sector could therefore be to require physical divestment of some of SP's and/or SSE's flexible generation in Scotland to reduce concentration levels and hence increase competition. There is evidence that this strategy was effective in reducing market power in the England and Wales Pool in the lead-up to NETA. It would not however address wider market power issues that are unrelated to constraints in Scotland. It may also not fully address constraint-related concerns in Scotland since as noted above there may be times when low market concentration (as measured by traditional 'static' measures such as HHIs) could still lead to times of significant market power. Therefore, the scale and level of divestment that would potentially be required to deal with these concerns could be impractical and undesirable for other reasons.

3.8. Such change could only arise as a result of MIR to the CC (which in and of itself would not of course guarantee this option as a CC outcome), although it could also be implemented via primary legislation. Our thoughts on the relative merits of a MIR and primary legislation are discussed in more detail in Chapter 5.

Virtual divestment

3.9. Another way to tackle concentrated ownership of generation would be to apply a virtual divestment. A virtual divestment is a hybrid between a behavioural and structural remedy. That is, it does not require physical divestment (i.e. legally no assets changes hand), but often the outcome mimics a structural divestment.

3.10. A virtual divestment could be applied through either sale of output or the option to purchase capacity or tender for the commercial operation of a generation unit(s). To resolve constraint-related market power issues, virtual divestment would require output to be backed by assets in specific locations, e.g. to resolve constraint concerns in a certain area generation assets in that area would need to be subjected to virtual divestment.

3.11. In the scenario of tender for commercial operation the third party would need to control both dispatch levels and bids/offers for one or more generation units. There are a number of other practical issues that would need to be arranged to make this option viable, such as implications for emission levels if a third party controlled

[23] HHIs based on actual capacity defined according to MEL (Maximum Export Limit) data from Elexon for each half-hourly period.

only some of the units at a generation plant. There would also be several practical issues in the scenario of sale of output (or option to purchase capacity) such as the relevant time period, e.g. a requirement to sell 10% of output on an annual, quarterly or all peak hours basis.

3.12. As with physical divestment, virtual divestment is unlikely to address all of the market power concerns identified. This option could only arise as a result of a MIR to the CC (which in and of itself would not of course guarantee this option as a CC outcome) or primary legislation.

Structure of transmission ownership

3.13. The structure of transmission ownership in GB, in particular the vertically integrated structure of the Scottish TOs, could be considered in order to address market power concerns in the BETTA market. The split between the SO and TO roles in Scotland means that the SO has only limited scope to optimise and manage constraints in Scotland that may give rise to market power, and may also dampen TO incentives to reduce constraints (e.g. by carrying out targeted investment in the transmission network) since they do not face the associated costs.

3.14. Another structural option to reduce the risk of undue exploitation of market power would therefore be to require the unbundling of ownership of transmission networks in Scotland. Similar to generator divestment, this option could only arise as a result of a MIR to the CC (which in and of itself would not of course guarantee this option as a CC outcome) or primary legislation, although the compromise text of the EC's Third Energy Package gives Member States the possibility to choose between three unbundling options both for gas and electricity markets: 1) Ownership Unbundling[24]; 2) Independent System Operator (ISO)[25]; and 3) Independent Transmission Operator (ITO)[26]. The UK Government has sought derogation from the Third Package requirements in relation to the Scottish TOs, but this is on the condition that the TOs make a satisfactory case that meets the terms of the derogation.

[24] Integrated energy companies must sell off their gas and electricity grids thus establishing separate TSOs, which handle all network operations. A supply and production company could not hold a majority share in a TSO.

[25] ISO model: Vertically Integrated Companies can keep network assets, but the network is managed by ISOs in which they have no significant stake.

[26] ITO model: Vertically Integrated Companies retain ownership of transmission assets, if they completely separate management thereof in an independent transmission operator, (also owned by the vertically integrated company) as long as there is a firewall between the VIC and ITO. This is subject to intrusive regulatory intervention (supervisory body, compliance programme, compliance officer).

4. Specific mechanisms for addressing market power concerns

Chapter summary

This chapter sets out two specific mechanisms for addressing market power concerns in the electricity wholesale sector: a new licence condition on generators; and an ex-ante price framework.

Question box

Question 1: Is a licence condition on generators appropriate? If so, do you have views on what form of condition is the most appropriate?
Question 2: How important would a formal appeals mechanism be?
Question 3: Is an ex-ante price framework an effective tool? If so, do you have any views on what would be the most appropriate form?
Question 4: Are there other specific mechanisms that will effectively address the issues identified?

4.1. We have identified two specific mechanisms that could address market power concerns: the first is to introduce a specific licence condition on generators, which would need to be enforced by Ofgem *ex-post* via investigation and sanctions for licence breach, while the second is to adopt a US-style *ex-ante* framework for controlling market power. Each of these approaches has advantages and disadvantages, which are discussed further below. Detailed design issues would need to be resolved if either option were to be taken forward, and we welcome initial feedback on these issues from respondents at this stage.

Licence condition on generators

4.2. Given the existing market arrangements, a Market Power Licence Condition (MPLC) to strengthen Ofgem's powers to carry out *ex-post* investigations of generator behaviour and impose fines or other sanctions if participants were found to be unduly exploiting a position of market power could be warranted. Such a licence condition could provide a robust long-term tool for addressing market power concerns. Once in place, a MPLC on generators may be quicker and easier to enforce than, for example, pursuing an abuse of dominance case under CA98. It would also have the advantage of being specifically tailored to the characteristics of the electricity sector, i.e. where market power can be intermittent or transient in nature but nonetheless very costly to consumers in certain periods, while also being difficult to erode over time through new entry.

4.3. Ofgem proposed a licence condition targeted at tackling market abuse in 2000. The CC subsequently upheld an appeal against its introduction. However, in its decision report the CC envisaged the possibility of the Secretary of State introducing new licence conditions if market power concerns proved to be a continuing problem under the market arrangements there were about to be implemented (known as NETA - the New Electricity Trading Arrangements): "*If, in the light of experience, such manipulation proves to be a significant problem under NETA and cannot be satisfactorily dealt with by rule modification, it will be open to the Secretary of State to consider using his powers under the Utilities Act to introduce new licence conditions to address the problem.*" In January 2008, the CC published a review of its decision on Ofgem's proposals that concluded: In January 2008, the CC published a review of its decision on Ofgem's proposals that concluded: "*the CC's decision not to support the introduction of the MALC* [Market Abuse Licence Condition] *in 2001 seems well-justified by subsequent market developments in Great Britain. Equally, however, Ofgem's view that such powers can be necessary in some circumstances also seems to be supported by subsequent developments overseas*."

4.4. We recognise that price spikes which reflect scarcity are an important part of a competitive market, and are necessary to reward and incentivise investment in generation. A MPLC would need to be carefully designed and targeted to ensure that only undue exploitation of market power was captured. In order to provide certainty and avoid the risk of dampening price signals for necessary investment, it would also be important to make it clear that generators who respond to overall scarcity would not be subject to enforcement action.

4.5. It would therefore be important for any new licence condition on generators to be carefully drafted to minimise any unnecessary uncertainty. For example, this could be achieved by:

- a high level obligation, together with some guidance on Ofgem's approach to enforcing the condition. For example, a pivotality threshold[27] could be specified as a criterion for when generators would be considered as possessing market power and therefore potentially subject to enforcement action under the licence if undue exploitative behaviour follows; or
- narrowing the scope of the licence condition, for example to focus only on particular circumstances where market power is likely to be present, such as when constraints are binding.

4.6. There is a trade-off between a narrowly drafted licence condition dealing with specific market power concerns, e.g. those related to constraints, and a broadly drafted licence condition. The former would minimise uncertainty on generators whereas the latter would ensure that Ofgem has sufficient powers to tackle a wide range of market power issues on an ongoing basis, including problems that may not have been envisaged at the time the licence condition was introduced (thereby reducing the risk that the purpose of the licence condition could be undermined with the associated increase in costs to consumers). To address this trade off,

[27] Pivotality analysis looks at whether demand can or cannot be met without the capacity of a given generator. A generator is said to be "pivotal" if it is required to meet a given level of demand.

consideration could be given to reducing the risk of uncertainty to generators in the event of implementing a more broadly drafted licence condition. This may be achieved by, e.g. clear enforcement guidelines and/or an appeal mechanism (possibly similar to that available under CA98). We welcome views from stakeholders at this stage as to how an appropriate balance could be struck between these two high-level aims.

4.7. Further, as mentioned in the Chapter 1, Ofgem recognises the potential for change in the market dynamics (e.g. consumers becoming more price sensitive and responsive due to smart metering) over the longer term. Any MPLC could therefore be subject to a review mechanism which would require Ofgem to review the appropriateness of retaining the licence condition from time to time.

4.8. There are several different ways in which a MPLC could be implemented. One way would be to introduce a standard licence condition (via the collective licence modification 'CLM' route). However, if this failed to secure the necessary industry support, we could refer the matter to the CC. This could either be done:

- as a modification reference under section 12 of the Electricity Act. We could either ask the CC to consider a particular modification or leave the form of licence condition open and simply set out the matter we consider operates against the public interest test; or
- as a MIR reference which, as discussed later in Chapter 5, would allow the CC to consider a wider set of remedies including potentially structural remedies.

4.9. An alternative option would be to seek to introduce a MPLC via primary legislation. A key advantage of legislation for the delivery of a MPLC is that it would allow the Competition Appeals Tribunal (CAT) to be designated as a route of appeal. We welcome views on the importance of having a formal appeal mechanism and possible vehicles for delivery of a MPLC.

4.10. We are also consulting on whether an Information Retention and Disclosure Licence Condition should be introduced. This would require companies to hold specific information, such as trading logs, for a period of time. It would mean that, if necessary, records would be available in the event of an investigation into alleged undue exploitation of market power. Whilst this may act as a deterrent in its own right to some degree, Ofgem would still need stronger enforcement powers to fully realise the benefits of such a condition.

Ex-ante regulation

4.11. A second specific mechanism, which is commonly applied in US electricity markets (e.g. in New York and New England), would be to introduce some form of *ex-ante* framework for controlling market power and potential undue exploitation. This could take various forms. For example, one option would be to implement a "structural screening" mechanism to identify specific regions and/or time periods where market power was likely to be present, either by reference to measures of pivotality in the market or through the identification of constrained regions and/or periods. Participants who met the structural screening criteria would then be subject to some form of regulatory mechanism to cap submitted bid and offer prices, for example with reference to:

- a cost of production benchmark;
- a marginal price; and/or
- an average of past BM bids and offers during periods when the generator was not pivotal.

4.12. The benchmark could be adjusted to reflect an appropriate balance between controlling for undue exploitation of market power and ensuring that investment signals are maintained: for example, either a "cost-plus" or a long-run marginal cost benchmark could be used rather than tightly regulating prices back to short-run marginal cost.

4.13. Alternatively, some US markets rely on "conduct-and-impact" screens which are used after bids are submitted in the day-ahead and real-time markets. Under such conduct-and-impact approaches, each supplier's bids are compared to a pre-defined reference level that approximates competitive bidding. If such bids exceed predefined thresholds over those reference levels, the supplier is said to have failed the conduct test. In such cases, the market price impact of the observed bidding behaviour is measured and if the unmitigated bids result in price increases above some predefined market impact threshold, generators that have failed the conduct test are also considered to have failed the impact test. Those that fail the two tests have their bids replaced with a reference level which is designed to approximate bidding under competitive conditions.

4.14. The key advantage of a US-style *ex-ante* regulation framework in Ofgem's view is that it may provide greater certainty to market participants regarding what is "acceptable" behaviour. In addition, it should be less complex to administer going forward than a licence condition which relies on Ofgem undertaking complex investigations of generators suspected of market abuse. This could reduce regulatory burden on market participants.

4.15. However, a potential downside of the *ex-ante* approach is that, similar to a "narrow" licence condition, it may not be sufficiently flexible to deal with all issues that could arise in the market. Furthermore, in the US the combination of automated bid price mitigation in constrained zones together with the application of relatively low price caps in the wider energy market has led many observers to comment on the "missing money" problem; prices may not rise sufficiently to attract new investment when and where it is required. In many US regions, further interventions, in the form of administered capacity payment mechanisms or must-run contracts for constrained plant, have been implemented to correct the "missing money" problem in the energy market. It may also be seen as overly "interventionist" by the standards of the GB market and hence could send a negative signal to investors. Moreover, ex-ante mitigation measures in the US regional markets are supplemented by federal market behaviour rules and anti-manipulation legislation. Finally, whilst an ex-ante approach would be relatively straightforward to administer once in place, it could incur considerable up-front implementation costs (e.g. in terms of system costs and changes to industry codes and settlement processes particularly within the Balancing and Settlement Code (BSC)).

4.16. This option could be taken forward under Ofgem's direction. It could be implemented, for example, under the auspices of a "Major Policy Review", which is one of the proposals currently out for consultation as part of the Code Governance Review, or through a MIR reference or seeking primary legislation.

5. Potential mechanisms for implementation

Chapter summary

This chapter considers potential mechanisms for implementation, including the possibility of a Market Investigation Reference (MIR) to the Competition Commission (CC) or seeking primary legislation.

Question box

Question 1: Do you have any views on the preferred mechanism for implementation?

5.1. The simplest and quickest route for implementing many of the changes identified as options in this paper, should any changes be required, would be for Ofgem to lead their implementation with the industry, e.g. in the case of a licence modification through the CLM process which can be implemented if no more than 20%[28] of relevant licensees[29] veto the change.

5.2. As discussed in earlier chapters, in order to pursue some options it would be necessary for Ofgem to make a MIR to the CC or to use the primary legislation route. Under a MIR, the CC would begin by undertaking a detailed investigation of the market as a whole and if it were to find that there are factors which significantly impede effective competition, it would propose remedies to deal with this. These may include structural remedies but could equally include changes to market arrangements or putting in place a new specific mechanism for addressing market power concerns such as those discussed in earlier chapters of this document. The CC would not be limited to proposals that have been considered by Ofgem, but would be free to develop new approaches to tackling any problems identified. It is not for Ofgem to predict or anticipate the proposals the CC is likely to make.

5.3. The key advantage of a MIR is that the CC would have the flexibility to consider a wide range of remedies, if it finds features of the market give rise to adverse effects on competition. There may also be benefit in seeking an independent view on the market arrangements. However, a MIR would also be time and resource intensive (it can take up to two years to reach recommendations on remedies) and would introduce considerable uncertainty in the market at a time when significant

[28] 20 per cent of relevant licence holders by number, or 20 per cent of relevant licence holders weighted by market share.
[29] Relevant licence holders are the holders of that type of licence and in which that licence condition is switched on at the closing date of the modification notice.

regulatory changes, such as those emerging from the TAR and the Energy Supply Probe, are already underway.

5.4. An alternative mechanism would be to seek new primary legislation. The advantage of this route is that it would be possible to include an appeal mechanism for allowing challenges to decisions taken as part of any option that was implemented. This may be considered desirable, e.g. in the case of a MPLC, since this could be one way to provide confidence to generators that pricing up in response to general market scarcity would not lead to enforcement. Clearly Ofgem cannot require or implement primary legislation as these are matters for Government and Parliament.

6. Ofgem's current thinking and proposed way forward

Chapter summary

This chapter explains Ofgem's current thinking on the proposals set out in this document and discusses the way forward from here.

6.1. Ofgem is concerned that the GB market is vulnerable to the undue exploitation of market power, both when there are constraints on the GB transmission system and more generally at times of system tightness. This vulnerability has increased over the past few years and is likely to increase further due to a number of factors such as reduced availability of transmission capacity due to maintenance outages while new investment is undertaken, a significant increase in new renewable generation connecting to the system and environment legislation limiting the use of certain generation capacity. There are policy developments being progressed, such as changes to the cash out arrangements and proposals emerging from TAR, which may mitigate concerns to some extent. Also, there is the potential that significant technological change in the market, such as the future roll out of smart meters, may mean that the concerns will reduce over time. Despite these factors, given the potential materiality of the concerns and consequent risk to existing and future consumers we believe there is a case for developing further proposals to address market power concerns.

6.2. There are several options that could potentially improve alignment between the incentives of the SO and TOs with respect to minimising the frequency and severity of transmission constraints. All of these options would alleviate to varying extents, but not fully address, our concerns.

6.3. There are a number of changes to other market arrangements that could play a role in helping to mitigate undue exploitation of market power in addition to those proposals that are already being considered. For example, changes to BM pricing could make it easier to detect possible undue exploitation of market power and could be combined with other regulatory approaches (such as a licence condition and/or *ex-ante* price regulation) for tackling market power concerns. However, these are not sufficient to fully address market power concerns. Moreover, there could be significant implementation costs and these could increase costs to consumers.

6.4. Ofgem considers that changes to the ownership of assets, such as requiring divestments by generators in areas where market power is thought to occur, may also not fully address market power concerns as, for example, there may be times when low market concentration could still lead to times of significant market power.

6.5. The key advantage of *ex-ante* regulation is that it could provide greater certainty to market participants regarding what is "acceptable" behaviour. In addition, it may be less complex to administer going forward than a licence condition which would rely on Ofgem undertaking complex investigations of generators suspected of market abuse. However, a potential downside of the *ex-ante* approach is that, similar to a "narrow" licence condition, it may not be sufficiently flexible to deal with all issues that could arise in the market. Furthermore, it could adversely affect investment incentives and could have significant upfront implementation costs.

6.6. A MPLC has the potential to fully address market power concerns. We note that any new licence condition would need to be carefully drafted to minimise any unnecessary uncertainty. We also note that there is likely to be a trade-off between reducing regulatory uncertainty through a "narrow" licence condition and/or more detailed guidance on Ofgem's approach to enforcing it, and ensuring Ofgem has sufficient powers to address market power concerns which may arise on a forward looking basis.

6.7. Given our view that neither changes to existing market arrangements nor asset-related changes are likely to fully address the concerns identified and therefore protect consumers sufficiently, Ofgem is currently minded to seek to address market power concerns through the introduction of a new licence condition with guidance on Ofgem's approach to enforcing it, which is broad and applicable to all generators, potentially combined with further consideration of some of the market arrangements options. Ofgem's current view is that it would be preferable to take forward this option under its own initiative in conjunction with industry, and hence would prefer a CLM rather than a MIR. However, at the same time Ofgem is considering the case for an appeal mechanism, which possibly could lend support to the option of seeking the use of primary legislation.

6.8. To inform our final proposals we would welcome feedback on all options raised, along with any others that stakeholders wish to bring forward. Following consideration of the consultation responses, Ofgem will look to issue a final proposals document on our preferred approach to tackling market power issues by the end of the summer.

Appendices

Index

Appendix 1 - Consultation response and questions

1.1. Ofgem would like to hear the views of interested parties in relation to any of the issues set out in this document.

1.2. We would especially welcome responses to the specific questions which we have set out at the beginning of each chapter heading and which are replicated below.

1.3. Responses should be received by Friday 8 May 2009 and should be sent and should be sent to gb.markets@ofgem.gov.uk for the attention of:

1.4. Ian Marlee
Director, Trading Arrangements
Ofgem
9 Millbank
London
SW1P 3GE

1.5. Unless marked confidential, all responses will be published by placing them in Ofgem's library and on its website www.ofgem.gov.uk. Respondents may request that their response is kept confidential. Ofgem shall respect this request, subject to any obligations to disclose information, for example, under the Freedom of Information Act 2000 or the Environmental Information Regulations 2004.

1.6. Respondents who wish to have their responses remain confidential should clearly mark the document/s to that effect and include the reasons for confidentiality. It would be helpful if responses could be submitted both electronically and in writing. Respondents are asked to put any confidential material in the appendices to their responses.

1.7. Having considered the responses to this consultation, Ofgem intends will look to issue a final proposals document on our preferred approach to tackling market power issues by the end of the summer. Any questions on this document should, in the first instance, be directed to:

- Ben Woodside/Leonie Bensted (GB Markets)
- 020 7901 7471/7323
- ben.woodside@ofgem.gov.uk or leonie.bensted@ofgem.gov.uk

CHAPTER: One

Question 1: Do you agree with our analysis of market power concerns in the GB wholesale electricity sector?
Question 2: To what extent should further policy intervention be progressed or are there alternative approaches that can be adopted for dealing with the concerns?

CHAPTER: Two

Question 1: To what extent to you think that changes to SO and TO incentives and/or changes to other market arrangements are likely to be effective in addressing the concerns discussed in Chapter 1?
Question 2: Are there any other changes to existing market arrangements that Ofgem should consider?

CHAPTER: Three

Question 1: To what extent do you think increased transmission investment is a feasible option and likely to effective in addressing the problem?
Question 2: To what extent do you think that the other asset related options discussed are likely to be effective in addressing the problem?
Question 3: Are there other asset-related remedies that Ofgem should consider?

CHAPTER: Four

Question 1: Is a licence condition on generators appropriate? If so, do you have views on what form of condition is the most appropriate?
Question 2: How important would a formal appeals mechanism be?
Question 3: Is an ex-ante price framework an effective tool? If so, do you have any views on what would be the most appropriate form?
Question 4: Are there other specific mechanisms that will effectively address the issues identified?

CHAPTER: Five

Question 1: Do you have any views on the preferred mechanism for implementation?

CHAPTER: Six

No question

Appendix 2– History of market power concerns in GB

1.1. This Appendix sets out a brief history of market power concerns in GB. It includes some high level findings from the recent Competition Act 1998 (CA98) investigation into SP and SSE, based on information which is already in the public domain or which is no longer confidential.

1.2. In GB, concerns over undue exploitation of market power by generators have been raised both under the old England and Wales Pool system and under the New Electricity Trading Arrangements (NETA), which were implemented in 2001 and subsequently extended to Scotland to form the British Electricity Transmission and Trading Arrangements (BETTA) in 2005[30].

1.3. Under the Pool, the most common concern related to the alleged withdrawal of generation capacity in order to increase the system marginal price (SMP) paid to all generators. Ofgem's predecessor, Offer (the Office of Electricity Regulation), launched investigations into Pool pricing behaviour on several occasions between 1991 and 2000. In the majority of cases, the investigations concluded that Pool prices were being influenced by the undue exploitation of market power on the part of the two main generation companies at that time (National Power and PowerGen).

1.4. Following these investigations, there were two rounds of plant divestment in which National Power and PowerGen agreed to divest significant generation capacity in order to increase competition in the wholesale market. The first round in 1996 took place in lieu of a reference to the Monopolies and Mergers Commission (MMC) by the Director General of Electricity Supply (DGES), while the second round in 1998 was the result of undertakings linked to the acquisition of regional electricity supply (retail) businesses. Both generators subsequently decided to divest further generation assets after 1999, although not in response to regulatory undertakings. This divestment programme, combined with substantial new entry in the sector and the changes to market rules brought in under NETA, is thought to have contributed to a decline in market power in the generation sector in England & Wales, with consequent benefits in the form of lower wholesale prices and lower retail tariffs for end consumers[31].

The Market Abuse Licence Condition (MALC)

1.5. Despite the perceived benefits of the divestment programme and the level of new entry, concerns remained over the ongoing scope for the potential undue exploitation of market power. This concern led the DGES to seek to introduce a

[30] A summary of the key features of the NETA/BETTA market is included at Appendix 3 of this document.
[31] Evans, J. & Green, R., 2003, "Why did British Electricity Prices Fall after 1998?", Cambridge Working Papers in Economics 0326, Faculty of Economics, University of Cambridge.

Market Abuse Licence Condition (MALC) into the licences of major generators in 1999. The wording of this condition would have prohibited any behaviour which amounted to an abuse of a position of substantial market power. Three specific criteria were required to be fulfilled in order to constitute a breach of this condition. Firstly, the generator had to possess substantial market power in the relevant time period. Secondly, the generator must have unduly exploited that market power. Thirdly, there had to be evidence that the undue exploitation of this market power had caused harm to consumers and/or competition. A proven breach of this order would have rendered the generator concerned open to an enforcement order by Ofgem, and civil action by those affected.

1.6. While the MALC focussed on the effect of the licensees' behaviour rather than the form of the behaviour itself, the guidelines specified particular types of conduct in the licence as potentially constituting an abuse, including:

- Acting to materially prejudice the efficient and economical balancing of the transmission system;
- Without good cause, limiting generation or capacity availability in ways that materially increase wholesale prices for electricity; or
- Pursuing discriminatory pricing policies by determining wholesale prices for electricity that differ unduly between times when market demand and cost conditions are otherwise similar.

1.7. The MALC was introduced in May 2000, with six of the major generators at the time agreeing to its inclusion in their licences. However, two generators (AES and British Energy) refused, and as a result the issue was referred to the Competition Commission (CC). The CC concluded the generators should not be forced to accept the modification to their licences. Some of the reasons for this decision were specific to the circumstances of the two companies concerned, but the CC also reasoned that the imminent introduction of NETA would reduce opportunities for the undue exploitation of market power, and that the condition could lead to regulatory uncertainty and risk deterring normal competitive behaviour.

1.8. However, the CC did not rule out the possibility that new specific licence conditions may be required. In its report on AES and British Energy in December 2000, the CC envisaged the possibility of the Secretary of State introducing new licence conditions if market power concerns proved to be a continuing problem under NETA: "*We are mindful of the disadvantages of a broad, effects-based prohibition… and our view that such a prohibition would not be suitable for dealing with manipulation of market rules. If, in the light of experience, such manipulation proves to be a significant problem under NETA and cannot be satisfactorily dealt with by rule modification, it will be open to the Secretary of State to consider using his powers under the Utilities Act to introduce new licence conditions to address the problem.*"

1.9. The CC published a review of several recent decisions including its decision on the MALC in January 2008. The CC's review concluded that: "*the CC's decision not to support the introduction of the MALC in 2001 seems well-justified by subsequent market developments in Great Britain. Equally, however, Ofgem's view that such* *powers can be necessary in some circumstances also seems to be supported by subsequent developments overseas*."

1.10. Although the MALC was removed from the licences of all generators following the CC's ruling in 2000, while it was in force Ofgem used it to investigate the conduct of both TXU and Edison Mission Energy (Edison). Ofgem found Edison in breach of the condition and Edison agreed to return mothballed generation capacity to the system. At the time, Ofgem did not have the power to fine the company for the licence breach, but if a similar condition were in force today then Ofgem would be able to levy a financial penalty of up to 10% of turnover against companies that breached the condition. In the case of an ongoing or likely future breach, Ofgem would also be able to put in place an enforcement order that could, for example, require a company to stop certain forms of behaviour or to reinstate generation capacity.

1.11. We note the concerns raised by both generators and the CC at the time of the MALC reference in 2000 regarding a lack of transparency in how the licence condition would be applied, and consequently a risk that the licence condition could increase regulatory uncertainty and deter normal commercial behaviour by generators. Similarly, the responses to Ofgem's initial findings report on the Energy Supply Probe[32], suggested that the majority of generators and suppliers were opposed to the possibility of Ofgem having additional regulatory powers to tackle wholesale market abuse, on the basis that it was not clear that this type of power was needed, and that it would increase uncertainty in the market and could potentially deter investment.

1.12. Ofgem acknowledges these concerns, although it has previously been unclear as to the extent of the materiality of the potential costs of this issue - we hope that this will lead market participants to reconsider their position.

Scottish constraints and the Competition Act investigation into SP and SSE

1.13. Since NETA was implemented in 2001, concerns over undue exploitation of market power have remained. In particular, since NETA was extended to Scotland via the BETTA arrangements in 2005, concerns over possible exploitation of market power arising from constraints between England/Wales and Scotland have been raised on several occasions. Ofgem has undertaken informal investigations into certain of these incidents, and in April 2008 launched a formal investigation under the Competition Act 1998 (CA98) into the behaviour of the two major Scottish generators, Scottish Power (SP) and Scottish & Southern Energy (SSE).

[32] See:
http://www.ofgem.gov.uk/Markets/RetMkts/ensuppro/Documents1/Energy%20Supply%20Probe%20-%20Initial%20Findings%20Report.pdf

1.14. The CA98 investigation followed allegations that SP and SSE could have abused a position of dominance arising from constraints between England/Wales and Scotland in September/October 2007. Specifically, the complainants alleged that the two companies may have withheld generation plant from the wholesale forward market while using the same plant to supply balancing power to NG at excessive prices. As noted above, similar concerns had been raised on several occasions since BETTA was introduced and these other periods were also included within the scope of the CA98 investigation.

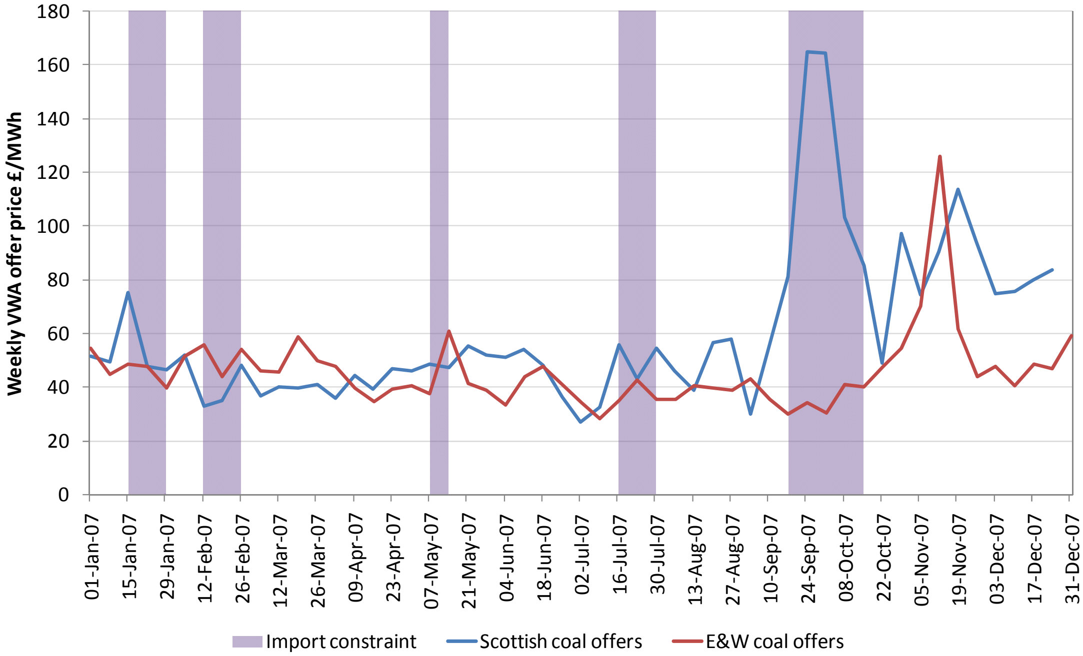
1.15. Ofgem closed the investigation into SP and SSE on 19 January 2009, noting that the likelihood of making an infringement finding under CA98 was low, and that other actions were available which could be more effective in addressing the issues raised on a forward-looking basis. However, we did identify several concerns in the relevant market, which are summarised below:

- balancing power supplied by SP's and SSE's generation units in Scotland appears to be much more expensive than that of comparable generators in England and Wales at times of constraint along the Anglo-Scottish boundary. This applies not just to output in the BM, but also to pre-gate contracts with NG and commercial inter-trip contracts; and
- there is also evidence that in at least some cases, SP and/or SSE may have behaved in ways that exacerbated, and in some cases created, constraint situations in relation to Scotland.

1.16. To illustrate our concerns regarding pricing differentials in the BM when constraints are active, two examples are presented below covering import and export constraint situations in turn. The first chart compares the weekly average volume-weighted accepted offer prices for coal plant in England/Wales and Scotland for 2007. These prices are based on public domain information on bid-offer acceptances. Ofgem has also obtained “tagged” data from NG on constraint-related actions, both in the BM and outside the BM (i.e., PGBTs, OTC trades and inter-trip arming). Periods in which NG data indicates an import constraint are also shown[33].

[33] On the chart, an import constraint is indicated if a constraint related action (BOA, PGBT, OTC) has been taken on any Scottish unit (not just coal) in any settlement period during the week to resolve an internal or cross-border Scottish import constraint.

Figure 1: Accepted BM offers in constrained and non-constrained periods – Scottish coal plant versus E&W coal plant Jan-Dec 2007



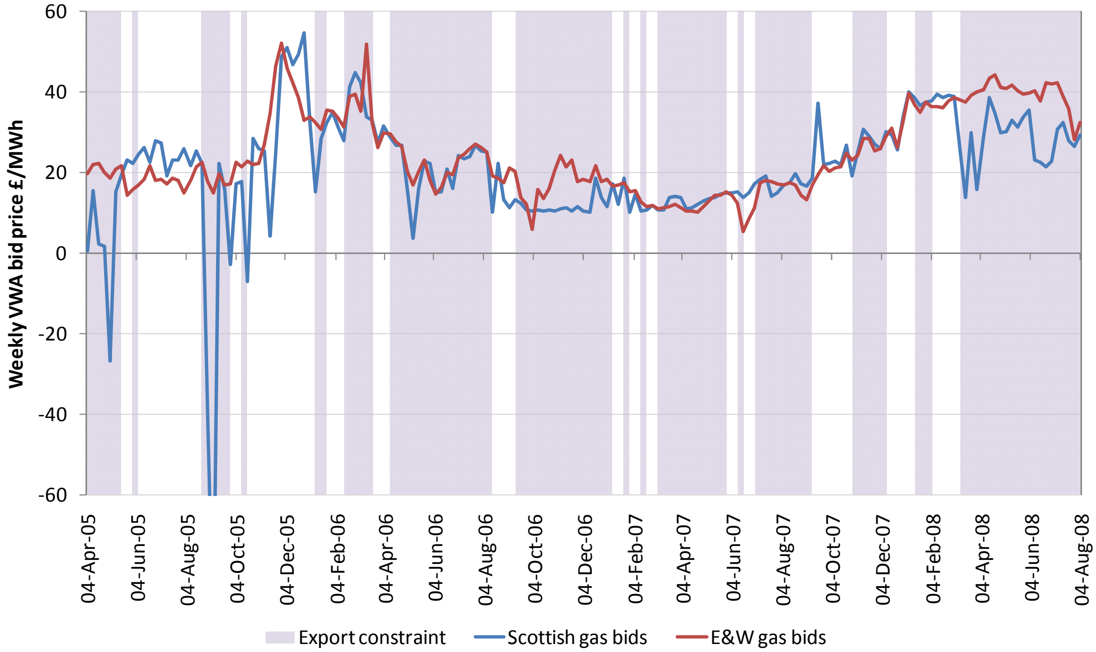
1.17. The above chart illustrates the large differential in accepted BM offer prices during the Sep/Oct 2007 import constraint period[34] as compared with other periods.

1.18. The second example considers the case of export constraints. Figure 2 below compares the weekly average volume-weighted accepted bid prices for gas plant in England and Wales and Scotland from the start of BETTA in April 2005 until August 2008. Periods in which NG tagged data indicates an export constraint are shown[35].

[34] A constraint occurs where the transmission system is unable to transmit the power supplied onto the transmission system to the location where the demand for that power is situated. An export constraint is said to occur where total generation output in a given area exceeds the sum of demand plus transmission capacity to export from that area (i.e. excess supply over demand on one side of a constraint. On the other hand, an import constraint occurs where there is an excess demand over supply on one side of a constraint.

[35] On the chart, an export constraint is indicated if a constraint related action (BOA, PGBT, OTC, inter-trip arming) has been taken on any Scottish unit (not just gas) in any settlement period during the week to resolve an internal or cross-border Scottish export constraint.

Figure 2: Accepted BM Bids in constrained and non-constrained periods, Scottish gas plant versus E&W gas plant April 2005-August 2008



Note: There were a number of accepted gas bids on 5th/6th Sept 2005 around -100£/MWh.

1.19. The above chart illustrates that export constraints from England/Wales and Scotland are present to some degree in most weeks. Large BM bid price differentials may be observed in a number of export constraint periods including September 2005 and summer 2008.

1.20. The table below shows that during export constraint periods, accepted coal bid prices in Scotland are 11 £/MWh lower on average than in other periods and are also 14 £/MWh lower than England and Wales coal prices at these times. In unconstrained periods, Scottish coal bid prices are 2 £/MWh lower. Accepted gas bid prices in Scotland are 9 £/MWh lower on average during export constraints than in other periods and are 10 £/MWh lower than England and Wales gas prices at these times.

Table 2: Volume-weighted average accepted bid prices (£/MWh), April 2005 to June 2008

		Region		
	Export constraint	Scotland	E&W	Diff
Coal	Yes	11.8	25.6	-13.8
	No	22.6	24.6	-2.1
	Diff	-10.8		
Gas	Yes	15.7	25.2	-9.5
	No	25.0	25.8	-0.8
	Diff	-9.3		

1.21. Regarding evidence that generators may, at times, have behaved in ways that exacerbated or created constraint situations, the investigation found that, in one case, this included the apparent withholding of "in merit" plant during import constraints despite positive spreads being available in the forward market, and also running pumped storage plant counter-cyclically in a manner that would have been likely to exacerbate import constraints. Other periods were identified in which either or both generators appeared to be running plant "out of merit" during export constraints. It is accepted that there may be mitigating circumstances which explain why a generating plant does not at times appear to follow economic dispatch principles. Nevertheless, there is sufficient evidence to give cause for concern that generators have the potential to exacerbate the requirement for constraint mitigation actions.

Appendix 3– Market arrangements

Overview of BETTA market arrangements

1.22. The BETTA market arrangements have been in place since April 2005 and have helped to facilitate competition in the GB-wide wholesale market for trading electricity (the previous NETA arrangements had applied only within England & Wales). Under BETTA and NETA, participants in the electricity market contract for the supply of electricity either on a bilateral basis or through organised exchanges such as APX. Each participant must notify its contractual position to the SO before real time.

1.23. The SO (NG) is responsible for ensuring the system is in balance at all times to avoid blackouts or overloads. The BM provides a residual market for balancing the system in real-time. Generators are free to choose whether to self-dispatch or offer into the BM.

The Balancing Mechanism (BM)

1.24. Parties trade to balance their positions day ahead and within day. To enable NG as SO to keep the transmission system in balance, the Grid Code requires each participant to submit, daily at 11am, an Initial Physical Notification ("IPN") of its contracted position for each of the half hour trading periods in the following day. Each participant's IPN may be amended at any time prior to "gate closure", which is one hour before the relevant half hourly trading period. At gate closure, an IPN becomes a Final Physical Notification ("FPN"), and these final positions are aggregated by NG and notified to the market[36].

1.25. At gate closure, NG as SO becomes the sole counterparty to all further trades and can adjust the levels of generation and demand to keep the transmission system in balance by using participants' Bids and Offers in the BM[37].

[36] Each participant must notify its contractual position for every half-hour trading period of the day to a central system operated by Elexon, the company that administers the Balancing and Settlement Code ("BSC") arrangements.
[37] Bids specify the price participants are willing to pay to NG to reduce generation or increase consumption by a specified volume, while Offers specify the price they will charge to NG to increase generation or reduce consumption by a specified volume. NG will normally accept the highest-priced Bids or lowest-priced Offers first, unless prevented from doing so by transmission constraints or the physical characteristics of the plant in question.

Balancing services

1.26. NG also uses other tools outside the BM such as standing reserve contracts and pre-gate closure transactions (PGBTs)[38] to balance the system. Collectively, these tools are known as Balancing Services. NG uses these services in order to manage the flows of electricity over the GB transmission system in order to:

- ensure the residual balancing of electricity supply and demand;
- ensure that the frequency and voltage of electricity on the system is maintained within the prescribed limits;
- manage constraints which have an impact on the frequency and voltage of particular parts of the system; and
- deal with emergency situations.

Charges and Payments

1.27. NG's actions in balancing the system give rise to charges and payments from and to participants in the BETTA market, including:

- Balancing Services Use of System Charges ("BSUoS"), which aggregate all the costs incurred by NG in balancing the electricity system in real-time, and charge these back to participants based on their proportion of the total market.
- Bid and Offer cash flows, which represent the charges or payments between NG and all BSC parties for changes to output due to accepted BM Bids and Offers.
- Balancing Services Contract Costs ("BSCC"), which are charged by NG for services procured from all participants in the electricity trading markets, regardless of whether they use the BM, to ensure the safe operation of the transmission system
- Energy Imbalance Charges ("EIC"), also known as "cash-out prices", which are the charges paid or received by any market participant based on the difference between their contracted energy position (as set out in the FPN) and their physical position according to actual outturn metered volume; and
- Residual Cashflow Reallocation Charge ("RCRC"): after physical imbalances have been financially settled, the remaining net cash flow is paid to or from all market participants in the same way as the BSUoS mechanism re-distributes or collects monies.

[38] PGBTs are fixed-price contracts struck between NG and a generator before the BM opens. They are another tool used by NG to help balance the system.

The GB transmission system

1.28. The transmission network has a finite capacity to transit electricity between any two locations. If flows on the system are too high, the network can overload which could lead to blackouts. On the other hand, in order for electricity to flow freely, the network must have sufficient capacity available. If insufficient capacity is available, the ability to meet demand for power in a particular area may be limited. A transmission constraint (referred to in this document as a "constraint") occurs where the transmission system is unable to transmit the power supplied onto the transmission system to the location where the demand for that power is situated, and can arise due to:

- the limitations on the thermal (heating) ratings of electric lines within the GB transmission system being exceeded;
- the inability to maintain voltages on the GB transmission system within prescribed limits set out in the Great Britain Security and Supply Standard (GBSQSS[39]); or
- limitations to ensure the transient and dynamic stability of electrical plant, equipment and systems directly or indirectly connected to the transmission system being breached.

1.29. It should be noted that constraints can arise under “normal” network conditions, simply due to the patterns of supply and demand on a given day. However, constraints are often triggered or exacerbated by transmission outages (which reduce the available capacity on the network) and/or generation outages (which disrupt the usual pattern of electricity supply).

1.30. In the event of a constraint, the SO will seek to reconfigure the system and/or take actions in the market to increase and decrease the amount of electricity at different locations on the network in order to manage the flow of electricity across the GB transmission system. The exact way in which a constraint is managed by the SO depends on a number of factors including the nature of the flows on the transmission system; the local level of generation output; and the local level of system demand. In the first instance, SO (NG) will normally seek to manage constraints by reconfiguring the transmission system: this includes, for example, splitting a substation to control power flows or switching a circuit out to manage high voltage issues. However, the constraint may still exist once all such actions have been exhausted and therefore require further management actions to be taken by the SO, such as:

[39] Condition C17 of the Transmission Licence requires NG and the Scottish transmission companies to act in accordance with the GBSQSS unless a derogation has been granted by the Authority. The GBSQSS sets out, among other things, the design criteria for the transmission system and for connections to that system, e.g. the capability to deal with faults/outages without exceeding equipment loadings or voltage limits.

- deferring transmission outages: if the constraint has arisen as a result of an outage due to maintenance or the installation of new transmission assets, deferring the outage where possible may avoid the constraint for the time being, but it will disrupt the construction programme and the constraint may then re-emerge at a later date;
- commercial inter-trips: when an intertrip arrangement is in place, additional power may be flowed over the relevant transmission lines without breaching the GBQSS, since if a selected circuit trips the generation or demand in question will automatically be disconnected to avoid the lines overloading**;**
- taking Bid-Offer Acceptances (BOAs) in the BM, in order to increase the level of local generation on one side of the constraint and reduce it on the other;
- entering into BMU-specific trades (Over-the-Counter ("OTC") trades or PGBTs) with particular generators, which achieve a similar impact as do BOAs in the BM but may have the advantage of allowing NG to negotiate prices ahead of real-time and reduce the risk of exposure to volatile prices in the BM; and
- negotiating longer-term bilateral contracts for constraint management, which may have a variety of terms depending on the contract in question.

1.31. In considering these actions by the SO, it should be kept in mind that more than one option may be available to manage a particular system issue in the circumstances prevailing at a particular time. It should also be noted that, typically, NG's options for the use of actions to manage constraints narrows the closer it is to real time.

Appendix 4 – The Authority's Powers and Duties

1.1. Ofgem is the Office of Gas and Electricity Markets which supports the Gas and Electricity Markets Authority ("the Authority"), the regulator of the gas and electricity industries in Great Britain. This Appendix summarises the primary powers and duties of the Authority. It is not comprehensive and is not a substitute to reference to the relevant legal instruments (including, but not limited to, those referred to below).

1.2. The Authority's powers and duties are largely provided for in statute, principally the Gas Act 1986, the Electricity Act 1989, the Utilities Act 2000, the Competition Act 1998, the Enterprise Act 2002 and the Energy Act 2004, as well as arising from directly effective European Community legislation. References to the Gas Act and the Electricity Act in this Appendix are to Part 1 of each of those Acts[40].

1.3. Duties and functions relating to gas are set out in the Gas Act and those relating to electricity are set out in the Electricity Act. This Appendix must be read accordingly[41].

1.4. The Authority's principal objective when carrying out certain of its functions under each of the Gas Act and the Electricity Act is to protect the interests of consumers, present and future, wherever appropriate by promoting effective competition between persons engaged in, or in commercial activities connected with, the shipping, transportation or supply of gas conveyed through pipes, and the generation, transmission, distribution or supply of electricity or the provision or use of electricity interconnectors.

1.5. The Authority must when carrying out those functions have regard to:

- The need to secure that, so far as it is economical to meet them, all reasonable demands in Great Britain for gas conveyed through pipes are met;
- The need to secure that all reasonable demands for electricity are met;
- The need to secure that licence holders are able to finance the activities which are the subject of obligations on them[42]; and

[40] entitled "Gas Supply" and "Electricity Supply" respectively.
[41] However, in exercising a function under the Electricity Act the Authority may have regard to the interests of consumers in relation to gas conveyed through pipes and vice versa in the case of it exercising a function under the Gas Act.
[42] under the Gas Act and the Utilities Act, in the case of Gas Act functions, or the Electricity Act, the Utilities Act and certain parts of the Energy Act in the case of Electricity Act functions.

- The interests of individuals who are disabled or chronically sick, of pensionable age, with low incomes, or residing in rural areas[43].

1.6. Subject to the above, the Authority is required to carry out the functions referred to in the manner which it considers is best calculated to:

- Promote efficiency and economy on the part of those licensed[44] under the relevant Act and the efficient use of gas conveyed through pipes and electricity conveyed by distribution systems or transmission systems;
- Protect the public from dangers arising from the conveyance of gas through pipes or the use of gas conveyed through pipes and from the generation, transmission, distribution or supply of electricity;
- Contribute to the achievement of sustainable development; and
- Secure a diverse and viable long-term energy supply.

1.7. In carrying out the functions referred to, the Authority must also have regard, to:

- The effect on the environment of activities connected with the conveyance of gas through pipes or with the generation, transmission, distribution or supply of electricity;
- The principles under which regulatory activities should be transparent, accountable, proportionate, consistent and targeted only at cases in which action is needed and any other principles that appear to it to represent the best regulatory practice; and
- Certain statutory guidance on social and environmental matters issued by the Secretary of State.

1.8. The Authority has powers under the Competition Act to investigate suspected anti-competitive activity and take action for breaches of the prohibitions in the legislation in respect of the gas and electricity sectors in Great Britain and is a designated National Competition Authority under the EC Modernisation Regulation[45] and therefore part of the European Competition Network. The Authority also has concurrent powers with the Office of Fair Trading in respect of market investigation references to the Competition Commission.

[43] The Authority may have regard to other descriptions of consumers.
[44] or persons authorised by exemptions to carry on any activity.
[45] Council Regulation (EC) 1/2003

Appendix 5 - Glossary

B

British Electricity Trading and Transmission Arrangements (BETTA)

The British Electricity Trading and Transmission Arrangements, created a fully competitive British-wide wholesale electricity market for the first time. The new arrangements were implemented on 1 April 2005 and followed on from the implementation of NETA in England and Wales in 2001.

Balancing Mechanism (BM)

The Balancing Mechanism is the principal tool used by the SO to balance the electricity transmission system on a second-by-second basis, by procuring commercial services (Balancing Services) from generators and suppliers post gate closure, in accordance with the relevant provisions of the Balancing and Settlement Code (BSC) and the Grid Code.

Balancing Services

The services that the electricity System Operator needs to procure in order to balance the transmission system.

Bid-Offer Acceptances (BOAs)

Acceptances by the SO of Balancing Mechanism offers to increase output on the system, or bids to reduce output on the system. The prices of BOAs form the basis for the calculation of the Energy Imbalance or cash-out prices.

Balancing and Settlement Code (BSC)

The legal document setting out rules and governance arrangements for electricity balancing and settlement in Great Britain. All licensed electricity generators and suppliers must sign up to the BSc and other interested parties may also choose to do so.

Balancing Services Use of System (charges) (BSUoS)

The charge levied by the System Operator on users of the transmission system, in order to recover the costs the SO incurs in the Balancing Mechanism and in procuring Balancing Services. They are charged on a half-hourly basis based on proportion of total output and demand

C

Cash-out prices

Cash-out prices (or Energy Imbalance Prices) applied to parties for their imbalances in each half-hour period.

Connection and Use of System Code (CUSC)

Constitutes the contractual framework for connection to, and use of, National Grid, SPT and SHELT's high voltage systems.

Constraint

There are various parts of the transmission network where import or export capacity is limited. Constraints can become active when this capacity limit is reached. An export constraint is said to occur where total generation output in a given area exceeds the sum of demand plus transmission capacity to export from that area (i.e. excess supply over demand on one side of a transmission constraint). On the other hand, an import constraint occurs where there is an excess demand over supply on one side of a transmission constraint. Constraints may require the SO to take ‘sub-economic’ balancing actions.

G

Great Britain Security and Supply Standard (GBSQSS)

The GBSQSS sets out, among other things, the design criteria for the transmission system and for connections to that system, e.g. the capability to deal with faults/outages without exceeding equipment loadings or voltage limits.

Grid Code

Code revised under BETTA to permit the development, maintenance and operation of an efficient, co-ordinated and economical system for the transmission of electricity, to facilitate competition in the generation and supply of electricity and to promote the security and efficiency of the power system as a whole. National Grid and users of its transmission system are required to comply with the Grid Code.

I

Inter-trip

Inter-trips are technical devices which are fitted to generation units to allow the unit to be "tripped off" in case of fault on the transmission circuit. Inter-trips increase system stability and so allow the SO to safely increase the capacity of a transmission line above its normal limits. Inter-trip contracts typically fix prices for a month at a time, and SO can activate the inter-trip at a few moments notice.

L

Large Combustion Plant Directive (LCPD)

An EU Directive placing restrictions on the levels of sulphur dioxide, nitrogen oxides and dust particulates which can be produced by combustion plants with a thermal output greater than 50MW. The implementation of the LCPD in the UK requires coal and oil plant to fit flue gas de-sulphurisation (FGD) equipment or have their total running hours restricted to 20,000 between 1 January 2008 and 31 December 2015 before closing prior to the end of that period.

N

New Electricity Trading Arrangements (NETA)

Under NETA, bulk electricity is traded on one or more exchanges and through a variety of bilateral and multilateral contracts. Those buying and selling electricity on exchanges and through bilateral contracts include not only generators and suppliers (who produce or consume physical quantities of electrical energy), but non-physical traders as well.

0

Over the counter (OTC)

Term used to refer electricity trading contracts which are negotiated directly between the parties concerned.

P

Pre-gate closure transaction (PGBT)

PGBTs are fixed-price contracts struck between NG and a generator before the BM opens. They are another tool used by NG to help balance the system.

S

System Operator (SO)

The entity charged with operating either the GB electricity or gas transmission system. NG is the SO of the high voltage electricity transmission system for the GB.

T

Transmission Owners (TO)

The entity charged with transmitting electricity from generation plants to regional or local electricity distribution operators.

Transmission system

The national high voltage electricity network, operated by the SO.

Appendix 6 - Feedback Questionnaire

1.1. Ofgem considers that consultation is at the heart of good policy development. We are keen to consider any comments or complaints about the manner in which this consultation has been conducted. In any case we would be keen to get your answers to the following questions:

1. Do you have any comments about the overall process, which was adopted for this consultation?
2. Do you have any comments about the overall tone and content of the report?
3. Was the report easy to read and understand, could it have been better written?
4. To what extent did the report's conclusions provide a balanced view?
5. To what extent did the report make reasoned recommendations for improvement?
6. Please add any further comments.

1.2. Please send your comments to:

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