BSC modification proposal P194 'Revised Derivation of the Main Energy Imbalance Price'

Impact assessment

January 2006

Summary

This document sets out, for consultation, Ofgem's Impact Assessment (IA) on a proposal to change the rules governing the wholesale electricity market. The industry and customers are divided on the proposal, although the majority do not support it. Ofgem thinks that the issue is finely balanced but is currently minded to approve the proposal.

National Grid Electricity Transmission (NGET), the System Operator (SO) for the GB electricity system raised modification proposal P194 'Revised Derivation of the Main Energy Imbalance Price'. The proposal seeks to modify the calculation of the main imbalance price. This is a very important part of the commercial arrangements often referred to as the "cash out arrangements" in the electricity wholesale market. These arrangements set the price that market participants pay if they fail to balance their contracted generation (supply) or demand with their physical supply and demand in a given period. The cash out arrangements ultimately provide the commercial incentives on generators and suppliers to maintain security of supply.

Electricity suppliers have strong incentives to contract with electricity generators to meet their customers' demand to avoid the risk of being exposed to cash out prices. Electricity generators have strong incentives to invest to maintain the reliability of their generating stations to meet their contractual commitments to suppliers without being exposed to cash out prices.

NGET as SO is responsible for operating the high voltage transmission system and keeping it balanced within safe technical limits. NGET buys or sells electricity from generators (or large customers who are able to quickly reduce their demand) to bring it back into balance. NGET also contracts with generators and large suppliers to hold a 'reserve' to keep the system in balance if, for example, there is a sudden loss of several large generators and/or a sudden, unexpected increase in demand. This is known as energy balancing.

NGET also take actions (also by contracting with generators, suppliers and customers) to resolve constraints on the transmission system. This could occur, for example, when the electricity supply and demand is in balance but there is not enough transmission capacity to transmit electricity from where it is being generated to where it is being consumed. This is known as system balancing.

In practice, NGET may contract with a generator, supplier or customer for both system and energy balancing purposes at the same time. The existing cash out arrangements are designed to separate out the costs of system and energy balancing. This is because market participants can manage the risk of being out of energy balance by contracting and investing appropriately. But NGET is better placed to manage the risks associated with system balancing through investment in its transmission system and contracting with generators and customers.

The cash out arrangements set an imbalance price that is designed to reflect the costs that NGET incurs in energy balancing every half an hour. This imbalance price then signals to generators and suppliers the costs of being out of energy balance in that half hour balancing period and provides them with a financial incentive to take actions to try to balance their own position. Generators and suppliers are not under any obligation to balance and can choose to pay the imbalance price. But the cash out price signals NGET's cost of balancing, and it should be expected that generators and suppliers will try to balance their own positions if they are able to do so at lower cost than NGET.

If the imbalance price does not reflect the costs that NGET faces and is either too high or too low, this will distort the commercial incentives on generators and suppliers. If the price is too low, generators and suppliers will not devote enough resources and effort to managing the risk of being out of balance. This could impact on security of supply if, for example, it encourages generators not to invest enough money to maintain reliability or it encourages suppliers not to contract to meet their customers' peak winter demand. But if the price is too high, generators and suppliers will devote too much resource and effort to managing these risks by, for example, investing too much to improve reliability or over-contracting. Although this may improve security of supply it will raise suppliers' and generators' costs and these additional costs will ultimately be recovered from customers.

Under Modification proposal P194 the main imbalance price would be calculated using the **volume weighted average** of a **pre-defined maximum volume** of the **most expensive** eligible energy balancing actions taken by NGET to balance the system. This is in contrast to the **existing arrangements** under which **the main imbalance price** is derived from the **volume weighted average of all** eligible energy balancing actions.

NGET rationale for the proposed change

NGET thinks that the existing arrangements result in the price being too low during certain periods and weaken the signals on market participants to balance, particularly at times of system stress when supplies are tight. NGET does not think the existing arrangements produce imbalance charges that fully reflect the costs incurred by the SO in balancing the system. NGET is concerned that these weak signals at times of system stress may impact on security of supply.

NGET has provided analysis and evidence that it considers show a lack of market response at times of system stress. It compares the imbalance price and the cost of the last (marginal, i.e. most expensive) action it took to balance the system during periods of stress. NGET's evidence suggests that if the cash out price had been calculated under the proposed modification methodology the signals to the market would have been strengthened and participants would have had stronger commercial incentives to balance their positions.

NGET recognises the risk that if imbalance prices were set based solely on the cost of the last (marginal) action taken, a very small, very high cost trade that did not reflect the costs of balancing electricity supply and demand on the system in that period could set the main imbalance price. This could lead to cash out prices being too high and raise costs to customers. In order to mitigate this effect, NGET considered it appropriate that the imbalance prices should be set on the volume weighted average of a pre-determined volume (100MWh) of the marginal eligible balancing actions it took (the Price Averaging Reference – PAR).

Elexon's consultations on the modification proposal

Elexon's assessment consultation and draft modification report[1] on modification proposal P194 (DMR) invited respondents' views on the proposal. A total of twenty five responses were received.[2] In addition to NGET, one integrated party, two generators and one trader were in favour of the proposed modification.

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[1] 'Draft Modification Report for Modification Proposal P194 'Revised Derivation of the Main Energy Imbalance Price'', Elexon, 14 October 2005, Assessment Consultation for Modification Proposal P194 'Revised Derivation of the 'Main' Energy Imbalance Price', Elexon, 7 October 2005

[2] The respondents represent a total of 74 BSC registered parties.

The other twenty respondents, (five suppliers, four generators, eight vertically integrated parties, two trading parties and one customer group) did not support the proposal and had the following concerns:

- that there was no evidence of a defect with the current cash out arrangements – NGET has never failed to balance the system in any period;
- higher imbalance charges would cause parties to over contract excessively, leading to greater balancing requirements on the SO;
- the proposal could lead to energy imbalance prices that are too high as it could lead to system balancing actions feeding into the calculation of energy imbalance prices;
- the proposal would penalise parties with limited opportunity to balance their own position and could present a barrier to entry; and
- the PAR 100MWh volume is an arbitrary value designed to deliver the desired results, and cannot be rationally justified.

A majority of the Balancing and Settlement Code Panel voted against this proposal. The Panel considered that it had not been demonstrated that the economic and efficient operation of the system would be better facilitated by this proposal. Furthermore, the Panel had significant concerns regarding P194's impact on certain participant types and its potential impact of certain (existing) imperfections in cash out.

Ofgem's analysis

Ofgem has carefully considered and analysed the proposal. There appear to be a number of important questions to analyse before assessing the merits of the proposal against the code objectives and Ofgem's statutory duties. These are:

- is there evidence to suggest that the existing arrangements give rise to cash out prices that are too low because they do not reflect the costs that NGET incurs in energy balancing?
- if there is evidence to suggest this, what might be causing this effect?

- what is the impact of this effect?

Our analysis, set out in this document, concludes that the current arrangements do not always provide correct signals at times of system stress. There appear to be four potential reasons why this is happening. These four reasons, which are not mutually exclusive, are set out below:

- **NGET's reserve contracting:** NGET often contracts for reserve and balancing services over a number of balancing periods. These contracts often consist of a fixed payment (in pounds) for providing the service and a variable payment (in £/MWh) when the contract is used by NGET. The current rules allocate the total costs (in pounds) that NGET incurs from these contracts into a cost (in £/MWh) in each balancing period. If the rules do not appropriately allocate the costs between balancing periods this could artificially reduce the imbalance price;

- **Constraint tagging:** the current rules try to remove the costs of system balancing actions through a process known as tagging. If these rules are not effective in distinguishing between energy and system balancing actions and/or remove higher priced energy balancing actions as well as system balancing actions this could artificially reduce the imbalance price;

- **Repricing of bids and offers:** the current rules could be working effectively but market participants may be unable to identify when the system is under stress in sufficient time to change the price they are willing to sell electricity to NGET for balancing purposes to reflect this scarcity. If this occurs then the volume-weighted average would fall below the marginal price, dampening the price signal sent by the cash out arrangements; and

- **Average v marginal:** if market participants do not reprice their bids and offers, the use of a volume-weighted average derivation of the main imbalance price rather than a marginal price may reduce the cost reflectivity of the imbalance price and hence the signals to market participants.

Ofgem's analysis has tried to determine which of these factors may be leading to cash out prices being too low and not sending appropriate signals at times of system stress. If the analysis suggests that the last factor is a significant cause of this effect, the proposed

modification may improve the existing arrangements and provide better price signals during periods of system stress. The potential costs and risks associated with the proposal would have to be weighed against this benefit.

Assessment of costs and benefits

As in all IAs, Ofgem has tried, as far as it is possible and appropriate, to quantify the potential costs and benefits of the modification proposal relative to the current arrangements. Where this is not appropriate or possible, Ofgem has sought to make a qualitative assessment comparing the anticipated performance of the proposal against the current arrangements. This assessment is summarised in Table 1 below.

Table 1: Summary of potential costs and benefits of the proposal[3]

	Net impact of P194	Quantification
Economy and efficiency	✓✓✓	
Competition and distributional	✓	-
Security of supply	✓✓	
Impact on environment	-	-
Risks and unintended consequences	✗	-
Implementation costs	✗	£350,000 (system) £10,000-£200,000
OVERALL ASSESSMENT	✓	

Ofgem's initial conclusions

The current cash out rules and arrangements are complex and clearly identifying the effects of changes to the rules or determining cause and effect when there is a problem is difficult. The industry carried out a significant amount of analysis in assessing the proposal. We have carried out further analysis, which is published in this IA. Ofgem's initial view, based on this analysis and respondents' views and having regard to the relevant objectives and Ofgem's statutory duties, is that the case for implementing the proposal is very finely balanced.

Although it is difficult to determine the precise magnitude of the impact of P194 in each area, on balance Ofgem is of the view that the analysis suggests that the proposal should

[3] This table is provided to provide an high level summary of Ofgem's initial assessment of the net impact of P194 in the different areas. Underlying this assessment is more detailed discussion or analysis of these points, highlighting assumptions made or highlighting potential areas of uncertainty. Hence, this summary table should not be seen as a substitute for reading the document nor does it fetter Ofgem's discretion.

provide more appropriate signals at times of system stress. The proposal should also reduce the impact of reserve on cash out prices, and may improve incentives to reprice, but it is unlikely to resolve (and may exacerbate) constraint issues.

In response to the views expressed by respondents who did not support the modification proposal, Ofgem considers that any increased barriers to entry and the effect on competition will be minimal. Furthermore, Ofgem's initial assessment is that any incentive on parties to effectively provide reserve (through over contracting) is likely to be appropriate as this is only likely to occur at times when this is necessary and efficient (i.e. at times of system stress). Ofgem does not think that the effects of the proposed modification on the environment are likely to be significant as any rise in effective levels of reserve is likely to be necessary or offset by a corresponding reduction in the levels held by NGET.

Although our analysis also suggests that P194 may have some potentially negative impacts, Ofgem considers that, on balance, its net impact would be positive. However, we also consider that this initial assessment is finely balanced and we would welcome views on the analysis we have undertaken, the assumptions we have made and the preliminary conclusions that we have drawn. We will carefully consider all relevant matters, including responses to this consultation, in reaching a final decision on the modification proposal.

Way Forward

Respondents are invited to provide views on this document by **23 February 2006**. We recognise that this only gives respondents four weeks to comment on this important modification. We would have liked to have been in a position to publish this impact assessment sooner. Unfortunately our resources have been diverted to other important work on gas prices this winter. This has delayed publication of the document. This proposed timetable will allow Ofgem to carefully consider responses before reaching our decision no later than the **23 March 2006.** This is the latest date that we can take this decision to allow it to be implemented this coming winter.

Table of contents

1. Introduction

1.1. The purpose of this document is to consult upon Ofgem's Impact Assessment (IA) in respect of the Balancing and Settlement Code (BSC) modification proposal P194 'Revised Derivation of the Main Energy Imbalance Price', hereafter referred to as modification proposal P194. This IA is being conducted in accordance with Ofgem's revised guidance on IAs published in June 2005.[4]

Modification proposal P194

1.2. National Grid Electricity Transmission (NGET) raised modification proposal P194 on 26 August 2005. Modification proposal P194 seeks to amend the 'Main' Energy Imbalance Price such that only a predefined volume of marginal balancing actions will contribute to the calculation of the volume weighted average imbalance price. Further details of modification proposal P194 are provided in Chapter 2.

Structure of this document

1.3. This document is structured as follows:

- Chapter 2 sets out the background to modification proposal P194;
- Chapter 3 sets out the key issues relevant for this IA;
- Chapter 4 attempts to evaluate the potential costs and benefits of modification proposal P194; and
- Chapter 5 sets out Ofgem's initial conclusions on the impact of modification proposal P194.

[4] "Guidance on impact assessments – Revised guidance", Ofgem, June 2005

Views invited

1.4. The analysis presented in this document provides estimates of the costs and benefits of modification proposal P194 based on high-level assumptions. Ofgem invites views on both the assumptions and estimates that have been made.

1.5. Ofgem would welcome views on this IA, to be received by close of business 23 February 2006. In accordance with its usual practice, Ofgem intends to make responses to this consultation available through the Ofgem library and website. Respondents may request that their response is kept confidential. Ofgem shall respect such requests, subject to any obligations to disclose information e.g. under the Freedom of Information Act 2000 or the Environmental Information Regulations 2004. Respondents wishing their responses to remain confidential should clearly mark the documents to that effect and include the reasons for confidentiality.

1.6. Responses should be addressed to:

Sonia Brown

Director, Wholesale Markets

Office of Gas and Electricity Markets

9 Millbank

London

SW1P 3GE

1.7. Electronic responses should be sent to wholesale.markets@ofgem.gov.uk.

1.8. Since January 2005 Ofgem has committed[5] to aim to set a minimum consultation period of 6 weeks for all IAs, and where the consultation period is shorter to explain why.

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[5] "Summary of responses to Ofgem's proposed Corporate Plan 2004 – 2007", Ofgem, January 2005

1.9. NGET, as System Operator (SO), has stated that it considers the implementation of modification proposal P194 in time for winter 2006 to be important to improve the efficiency of system operation and the incentives on companies to maintain security of supply. The Panel has recommended that the proposal can only be implemented ahead of winter 2006 if the Authority's decision is received no later than 23 March 2006.

1.10. In view of this timetable, the importance that the SO has placed on this modification proposal and Ofgem's duties in relation to security of supply, Ofgem considers that, without prejudice to what our decision will be in respect of this modification proposal, this issue should be given urgent attention since it is important that the decision is reached in sufficient time to allow implementation of the proposal before winter 2006, should our decision be to direct the modification.

1.11. To enable Ofgem to meet this deadline, we are unable to consult on this IA for longer than 4 weeks. We had hoped to publish the IA sooner but have had to undertake the necessary analysis at the same time as completing other, high priority unplanned work such as investigating movements in spot gas prices and dealing with a number of urgent gas modifications for winter 2005/06. As the issues raised by this modification are well known to the industry, particularly after their discussion at the recent series of Cash Out Review Working Group (CORWG) (see Chapter 2 below) meetings organised by Ofgem, we think that 4 weeks will give interested parties sufficient time to provide informed responses.

1.12. If you wish to discuss any aspect of this paper please contact Kevin James on 020 7901 7181 or Ben Woodside on 020 7901 7471, who would be pleased to help.

Way forward

1.13. Ofgem will carefully consider responses received to this IA on modification proposal P194 to help inform the Authority's final decision. The initial views expressed in this IA are entirely without prejudice to Ofgem's final consideration as to whether to accept modification proposal P194, which will take into account all relevant considerations, including, among other things, the responses received to this IA. We do not intend to publish a final IA, as described in our guidance for IAs[6] because of the timescales outlined above. We will, however, include all relevant conclusions in our decision document. We intend to make a decision on modification proposal P194 by 23 March 2006.

1.14. In the event that the Authority determines that the modification proposal should be made, the necessary changes to the BSC are planned to be implemented by 2 November 2006.

Consultation code of practice

1.15. If respondents have comments or complaints about the way this consultation has been conducted these should be sent to:

Michael Fews

Head of Licensing

Office of Gas and Electricity Markets

9 Millbank

London

SW1P 3GE

michael.fews@ofgem.gov.uk.

[6] "Guidance on impact assessments – Revised guidance", Ofgem, June 2005

2. Background

2.1. This chapter provides background information on:

- the purpose of the cash out arrangements;
- the current cash out arrangements;
- the principal issues in respect of marginal and average imbalance price calculations; and
- modification proposal P194.

Purpose of cash out arrangements

2.2. Under the rules of the BSC, a Party is in a position of imbalance if its notified contract volume does not match its metered volume, i.e. the Party is producing (or consuming) electricity which has not been sold (or bought) and is therefore not covered by contracts. Imbalance settlement, or 'cash out', is designed so that any electricity produced or consumed that is not covered by contracts is paid (or charged) for at a price that reflects the costs incurred by NGET in rectifying the resultant overall system imbalance. The arrangements are designed to target the costs that NGET has incurred in buying and selling electricity to balance generation and demand on the system onto those Parties with an imbalance, i.e. those Parties on behalf of whom the System Operator (SO) has taken Electricity Balancing actions.

2.3. All participants who have bids and offers accepted by the SO within the Balancing Mechanism (BM) for the purposes of energy or system balancing receive the amount for the trade according to their offer or bid price. The amount participants receive for the bids or offers made in the BM is therefore unaffected by the cash out arrangements.

2.4. Cash out prices are important in sending appropriate price signals and creating the necessary commercial incentives on companies to facilitate the efficient

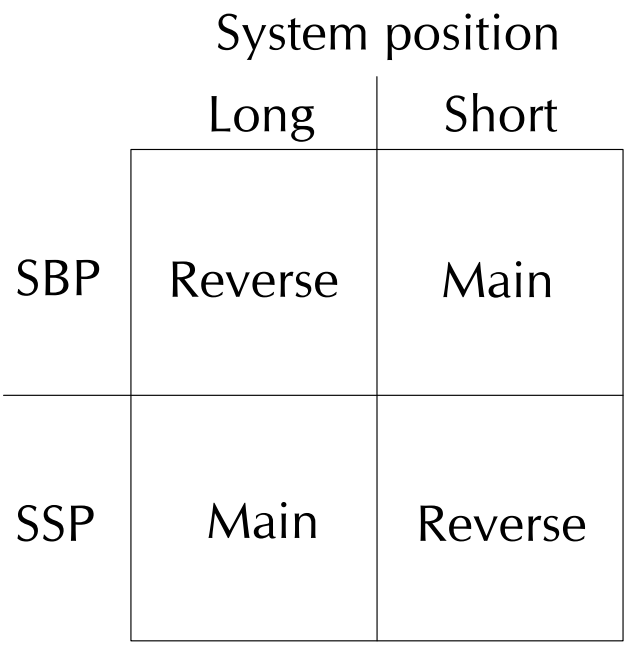
operation of the system and maintain security of supply. For suppliers, the potential to be exposed to high cash out prices during periods of peak demand provides the incentive to contract with generators in advance to meet their customers' peak demand.[7] For generators, the potential to be exposed to high cash out prices following, for example, a mechanical failure, during periods when margins are tight provides an incentive to maintain their plants and to contract with other peaking plants to provide physical cover, and thus maintain the generation levels necessary to meet their contracted demand, with an appropriate margin to spare.

Current cash out arrangements

2.5. The current cash out arrangements consist of a 'dual' cash out mechanism. This means that there are two Energy Imbalance Prices, or 'cash out prices': the System Buy Price (SBP) and the System Sell Price (SSP). These are further defined in any given settlement period as the 'main' energy price, which applies in respect of imbalances in the same direction as the imbalance of the system, and the reverse price, which applies to imbalances in the opposite direction. For example, Figure 1 illustrates that if the system as a whole was short, then the SBP would be the main price and the SSP is the reverse price.

[7] Suppliers can also contract with their customers for demand-side response, whereby they reduce or limit their demand during periods of peak system demand.
BSC modification proposal P194 'Revised Calculation of the Main Energy Imbalance Price', Impact Assessment

Figure 1: Energy Imbalance pricing



2.6. The main Energy Imbalance Price is determined using a volume weighted average of all the eligible[8] Electricity Balancing actions taken by the SO to alleviate the Net Imbalance Volume[9] (NIV). The reverse price is derived from a market price based on short-term energy trades made in the forward and spot markets.

2.7. The cash out arrangements seek to exclude the costs of 'system balancing' (for example the costs of resolving transmission constraints) from the calculation of cash out prices since these are only meant to reflect energy balancing costs. To do this a number of rules (summarised in footnote 8) are applied to 'tag out' system trades and remove them from imbalance price calculations.

2.8. Imbalance revenues received from those with short positions feed into a central fund from which the imbalance payments to those with long positions are made. However, for most settlement periods the imbalance payments and

[8] Defined as actions that are not: Bids or Offers which have a Continuous Acceptance Duration of less than 15 minutes; De Minimus accepted Bids or Offers; Arbitrage accepted Bids or Offers; NIV Tagged Bids or Offers; or System actions identified in the BSAD methodology.

[9] The NIV is calculated by netting off all purchase actions against all sell actions to give the imbalance of the overall System.

revenues do not match exactly and consequently an imbalance cashflow surplus or deficit is created. The net surplus/deficit resulting from summing the imbalance payments and revenues for all market participants is returned to/recovered from market participants via Residual Cashflow Reallocation Cashflow (RCRC) payments, which are based on participants' metered volumes.

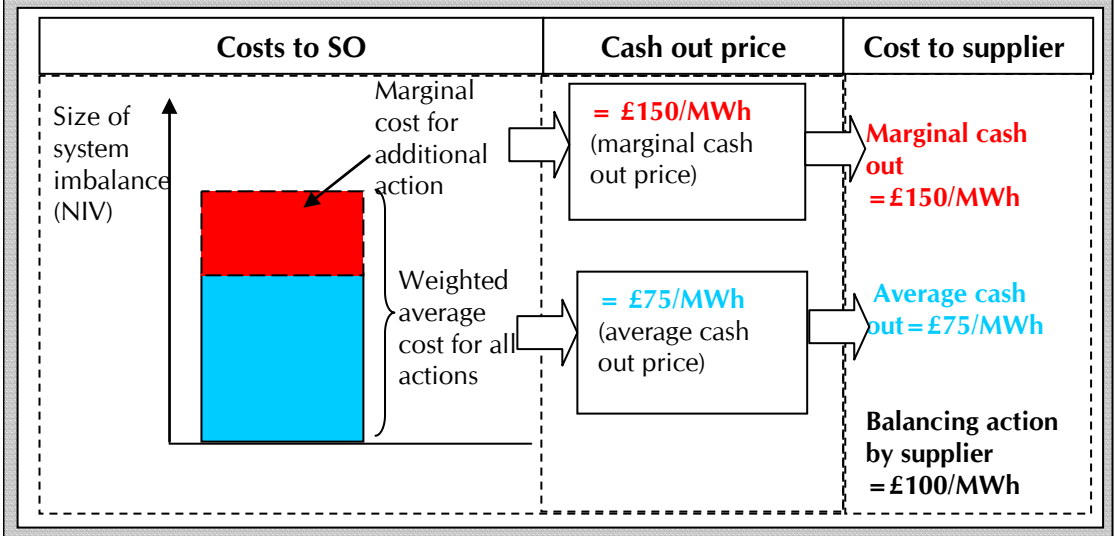
Average vs marginal imbalance prices

Reflecting the costs of system actions

2.9. Cash out prices that properly reflect the marginal – rather than the average – cost of resolving energy imbalances will tend to promote efficient behaviour and reduce the total costs of balancing the system. An example showing why this tends to be the case is set out in Box 1 below. This example shows that if the cash out price does not reflect the marginal costs of balancing, but the average cost, then this can reduce the incentives for market participants themselves to resolve the imbalance more cheaply than the SO. It should be noted that market response in any given situation is in fact determined by a complex interplay of many factors.

Box 1: Example of potential impact of marginal and average cash out pricing on incentives

The following simple example tries to show why cash-out prices that reflect marginal – rather than the average – cost of resolving energy imbalances will tend to promote efficient behaviour and reduce the total costs of balancing the system.



Suppose that cash-out prices are, as present, based on the average cost of resolving imbalances, that the marginal cost of solving another MWh of energy imbalance is 150 £/MWh, and that the average cost of resolving energy imbalances (and hence the cash-out price) is 75 £/MWh. Suppose also that a supplier may shortly go out of balance, but that it could take an action to avoid the imbalance which costs 100 £/MWh.

If the party faces the average imbalance price of 75 £/MWh, it will clearly not take the 'avoiding' action which costs 100 £/MWh. As a result, the SO must take a (marginal) balancing action with a cost of 150 £/MWh. This is inefficient and the SO spends 50 £/MWh more to resolve the imbalance than necessary (i.e. the difference between the relatively cheap avoiding action the market party could have taken and the more expensive marginal cost of resolving an energy imbalance). If the cash-out price does approximate the marginal price then the market participant would face a cash-out price of about 150 £/MWh and would take the cheaper, 100 £/MWh action to avoid the imbalance and the cash out price, saving £50/MWh.

2.10. Accordingly, where market participants have an ability to respond to cash out signals, the amount by which the cash out price (or the average price from which the cash out price is derived) deviates from the marginal price provides a reasonable indication of the potential inefficiency of the balancing arrangements. Therefore, Ofgem has dedicated significant effort in this IA to analysing the difference between average and marginal balancing costs, and the reasons for these differences.

Why an average cash out price was introduced

2.11. Even under the current regime, where cash out prices reflect average costs, economic theory suggests that the average cost (to the SO) should tend toward the marginal cost. This is because generators supplying balancing power are compensated on a 'pay-as-bid' basis[10]. Under a pay-as-bid auction, it would be rational for participants to submit offers (and bids) close to their expectation of the costs of the marginal action that will be accepted by the SO i.e. the most expensive (and cheapest) plant.[11] Over time, if sufficient information is available to participants for them to be able to discover and reasonably anticipate the level of prices that would set the marginal trade, it would be rational for them to adjust their offers (and bids) to be just below (above) the marginal price. However, analysis of actual imbalance prices shows that there is a divergence between marginal and average prices in certain periods, particularly when the system is under stress, see Figure 3.

2.12. Prior to the introduction of the New Electricity Trading Arrangements, Ofgem shared the view of many market participants that imbalance prices should be calculated from a volume weighted average of accepted offer and bid prices in the BM as this would best reflect the costs incurred by the SO in balancing the system and ensure that appropriate signals and incentives were created, for example, by allowing short-term price signals to emerge at times of system stress.

2.13. Ofgem was concerned that marginal cash out prices could create distortions because they could be set based on a very small volume of energy accepted by the SO or alternatively based on a System Balancing action. Ofgem was also concerned that a marginal cash out regime could increase the risk of manipulation to drive up cash out prices and market prices to levels that would not reflect underlying market conditions particularly when the system is not

[10] In other words, they will be paid according to their offer or bid price, rather than the highest price accepted.

[11] For example, suppose that the electricity system is short so that the SO has a requirement to accept offers from generators. If generator A has an expectation that the marginal price will be set by generator B at a price of 150 £/MWh, then it would be more rational for it to price close to this marginal price than continue to submit a lower priced offer.

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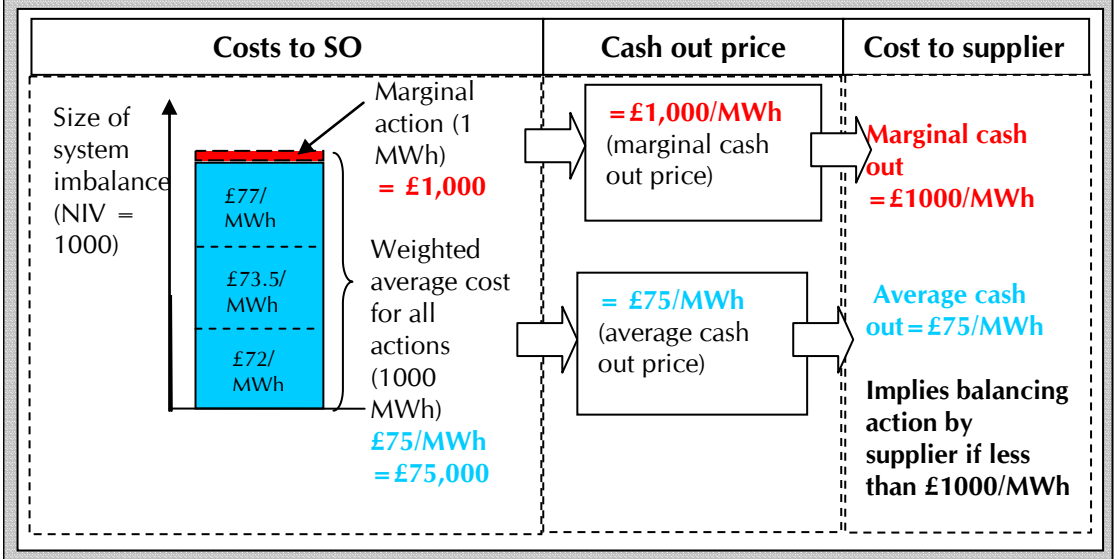
under stress. Box 2 below provides a stylised example of this potential risk.

Box 2: Impact of marginal cash out based on small 'unrepresentative' trades

The following simple (stylised) example tries to show potential costs if small unrepresentative marginal action sets the cash out price. In this example an unrepresentative trade could be viewed as a trade where the price is excessive (i.e. reflects market power not the true marginal cost of energy).



Suppose that the system is short by 1000 MWh and that the SO accepts offers as set out in the diagram above. The marginal cost of solving another MWh of energy imbalance is 1000 £/MWh. The weighted average price is approximately 75 £/MWh. Therefore the total cost to the SO of resolving the 1000 MWh imbalance is (average price *1000) = £75,000.

In this example, the marginal accepted offer of 1 MWh sets the marginal cash out price of 1000 £/MWh. If the party faces this imbalance price, it would take 'avoiding' action provided this action is cheaper than the marginal cash out price (i.e. less than 1000 £/MWh). However, because the marginal cash out price is unrepresentative (i.e. based on excess pricing by a generator with market power) suppliers/generators could spend too much to avoid being out of balance relative to the true costs of imbalances.

It could still be the case that if the party faces the average imbalance price of 75 £/MWh, it will clearly not take the 'avoiding' action which costs more than 75 £/MWh. If the "true" cost of the marginal balancing action by the SO is greater than 75 £/MWh, then there will be some inefficiency (as explained in Box 1). Nevertheless, if there is an opportunity for small unrepresentative trades to set the marginal price quite frequently, then it may be the case that the average cash out pricing could avoid these larger distortions, even if the average methodology is imperfect.

In this example, there are incentives for a generator with market power to set the marginal action, not only because it would receive a payment from the system operator for the balancing action. It would also impose costs on its competitors who are out of balance and would therefore increase the incentives on companies to contract with the generator at these sorts of price levels in future to avoid being out of balance.

2.14. In addition to concerns set out in Box 2, Ofgem also had concerns about the potential for marginal cash out prices to distort the market through the RCRC mechanism.[12]

2.15. In view of Ofgem's concerns and the theory that the average price should tend towards the marginal price anyway, an average approach to the calculation of electricity cash out prices was introduced.

2.16. It should be noted that the methodology in electricity based on weighted average of eligible offers differs from the approach adopted in the gas market, which is based on the marginal action taken by the SO.

Proposed modifications to cash out arrangements

2.17. Since the introduction of the cash out arrangements a number of modification proposals have been made to the way in which the energy imbalance prices are calculated, intended to address concerns that the rules did not give rise to prices that reflected costs and market conditions.

2.18. During the winter of 2003/04 a number of modification proposals in this area were considered and rejected by the Authority on the basis that they did not better facilitate achievement of the applicable BSC objectives.[13] However, in the Authority's decision letters in respect of modification proposals P135-137 and P144[14] Ofgem highlighted several areas where it considered potential improvements could be made in respect of the Energy Imbalance Price calculations.[15]

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[12] In the example in Box 2, the difference between cash out revenues (£1 million) and actual SO balancing costs (£75,000) implies a large sum of money to be passed back to market participants.
[13] Details of Modification proposals 135,136,137 and 144 are provided in appendix 1.
[14] Modification Proposal P135: 'Marginal System Buy Price During Periods of Demand Reduction', Modification Proposal P136: 'Marginal Definition Of The 'Main' Energy Imbalance Price', Modification proposal P137 'Revised Definition of the System Buy Price and System Sell Price', Modification Proposal P144 'Removal of CADL from the BSC'
[15] See Appendix 1 for details.
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Cash out review working group (CORWG)

2.19. In May 2004, Ofgem initiated a review of cash out arrangements to consider, among other things, possible improvements to the calculation of the Energy Imbalance Prices.[16] As part of this review, in August 2004 Ofgem established the CORWG to look at the cash out arrangements in a systematic way.[17]

2.20. Since then the CORWG sub-groups have conducted analysis relating to potential defects of the current cash out arrangements. Where appropriate, Ofgem has utilised or further developed the CORWG's analysis for the purposes of this IA (as indicated in the document).

2.21. The CORWG identified a number of reasons why outturn energy imbalance prices do not always support the theory that average prices should tend to the marginal prices. These included:

- insufficient information available to market participants ;
- inclusion of actions taken by the SO to alleviate system constraints, within the stack of trades used to calculate imbalance charges due to limitations with the tagging mechanism,
- inclusion of non-BM balancing actions[18], and
- operational barriers[19].

2.22. The CORWG generally agreed that, in theory, a marginal price is a more efficient mechanism than an average price in terms of signalling scarcity or

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[16] "Electricity and gas cash out review – a consultation document", Ofgem, May 2004
[17] "Gas and electricity cash out review: the way forward", Ofgem, August 2004

[18] Rather than rely solely on the BM to resolve imbalances, NGET contracts ahead for reserve. There are various mechanisms to allocate the costs of contracting ahead as accurately as possible to the periods in which it is utilised. The way in which this can impact on cash out prices is explained in more detail in Chapter 3.
[19] For example, the technical capability of generation plant to change its output rapidly.
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excess energy. Further details of the work of CORWG can be found on the Ofgem website[20].

Modification Proposal P194

2.23. Modification proposal P194 was raised by NGET on 26 August 2005. It seeks to amend the cash out price calculation by restricting the calculation of the main price to the volume-weighted average of a pre-defined maximum volume of the most expensive balancing actions.[21] Under modification proposal P194 this volume would be set to the 100MWh (referred to as the 'Price Average Reference' (PAR) 100 Volume) of the most expensive (to the system) balancing actions remaining following the tagging procedure.

2.24. If the volume of the eligible balancing actions is less than 100 MWh then, as now, all the eligible balancing actions would be included in the volume weighted average. The proposal would not change the tagging mechanism or the calculation of the reverse price.[22] All bids and offers accepted by the SO through the Balancing Mechanism would continue to be paid as bid / offered as under the current arrangements.

2.25. The BSC Panel considered the P194 Assessment Report at its meeting on 10 November 2005. At that meeting the BSC Panel reached a provisional recommendation, for inclusion in the draft Modification Report, that modification proposal P194 should not be made. At its meeting on 08 December 2005, the BSC Panel considered responses to the draft Modification Report and reached a majority recommendation to the Authority that modification proposal P194 should not be made.[23]

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[20] CORWG documents, including slides outlining its conclusions can be found at www.ofgem.gov.uk/ofgem/work/index.jsp?section=/areasofwork/cashoutreview

[21] Rather than using the volume weighted average of all priced balancing actions which are not De Minimus, Arbitrage, CADL or NIV tagged for the main price.

[22] A full description of modification proposal P194 can be found on the Elexon Website: http://www.elexon.co.uk/documents/Consultations/P194_Assessment_Consultation

[23]The Final Modification Report is available at: http://www.elexon.co.uk/documents/Contact_ELEXON/contact_related_documents/P194MR_FINAL_10.pdf BSC modification proposal P194 'Revised Calculation of the Main Energy Imbalance Price', Impact Assessment

3. Key issues

3.1. This chapter outlines the main issues that Ofgem has identified as requiring consideration in relation to modification proposal P194. In identifying these issues, Ofgem has had regard to the applicable BSC objectives and our wider statutory duties. We will make our decision in respect of this modification proposal on the basis of these statutory duties and our assessment of whether it has been demonstrated that the modification proposal better facilitates the applicable objectives of the BSC compared to the current baseline. As such, to implement the proposal, Ofgem needs to understand any weakness with the current arrangements and to conclude that adopting Modification Proposal P194 would lead to the applicable objectives being better facilitated. In compiling the list of issues to consider, we have also taken account of responses to the BSC modification reports.[24]

3.2. We think that the principal areas on which the potential effects of Modification Proposal P194 must be considered are:

- economy and efficiency;
- competition and distributional impacts;
- security of supply;
- impact on the environment; and
- risks and unintended consequences.

3.3. For each issue, we have considered whether the current cash out mechanism is providing appropriate signals of the costs the SO faces in balancing supply and demand, and if not, what effect this is having. We then discuss the likely

[24] The Draft and Final Modification Reports for P194 prepared by Elexon on behalf of the BSC panel are available at:
http://www.elexon.co.uk/changeimplementation/ModificationProcess/ModificationDocumentation/modProposalView.aspx?propID=212
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impact of modification proposal P194 in this area, and whether it represents an improvement on the current arrangements.

Economy and efficiency

3.4. In this section, we examine whether the modification proposal will improve the economic and efficient operation of the system. The system will function most efficiently where each party faces charges that reflect the costs incurred by the SO in balancing the system. This will encourage parties to take steps to balance their own positions where they are able to do so at a lower cost than the SO. This, in turn, will reduce the overall costs of balancing.

3.5. In assessing whether modification proposal P194 would improve the economic and efficient operation of the system through improving the investment and operational signals and incentives resulting from the cash out arrangements Ofgem considers it is necessary to:

- assess the effectiveness of the signals which arise from the current cash out arrangements both under normal market conditions and in periods during which the system is under stress (i.e. the margin of available generation over actual/forecast demand is relatively tight);
- identify and assess the factors that may be dampening the signals being sent through the current cash out arrangements; and
- assess the extent to which the signals will be improved as a result of a move to a more marginal derivation of cash out prices under modification proposal P194.

3.6. As stated in Chapter 2, the gas cash out arrangements are based on a marginal price derivation. It is also important to consider the interactions between the two regimes in order to assess the likely effect of the modification proposal on the gas market as well as the electricity market. This is important because a significant proportion of electricity generators are gas-fired.

Are existing cash out prices providing appropriate signals?

3.7. In considering whether the existing cash out arrangements are providing appropriate signals to the market it is necessary to consider the existing arrangements and resulting cash out prices that apply during both normal market conditions and times of system stress.

What factors may be dampening signals?

3.8. If the analysis demonstrates that the cash out signals are being dampened either under normal conditions and/or at times of system stress, it is important to understand why this is happening. Through consideration of the points raised by respondents to Elexon's assessment consultation and draft modification report (DMR), the work carried out by CORWG and further consideration by Ofgem, we have identified the following areas which may be influencing the cash out signals:

- **NGET's reserve contracts:** the smearing across all periods of the option fees paid by NGET to have reserve available for use in only a few periods could distort the cash out price;

- **repricing of bids and offers:** there may be barriers which prevent market participants from adjusting their bid and offer prices to reflect market conditions in different periods. The extent to which bids and offers are static and do not respond to market signals, could be reducing the cost reflectivity of the cash out prices;

- **tagging:** if current mechanisms for removing 'system actions' from the NIV stack are not working properly so that energy actions are removed or system actions remain in the stack, cash out prices could be distorted; and

- **average derivation of cash out prices:** if cash out prices derived from the weighted average price of balancing actions are not tending towards the marginal price (for example, because participants are not repricing their bids and offers), the signals from those prices may not be appropriate.

3.9. These factors are not mutually exclusive so that, to the extent that cash out signals are being dampened, it could be a result of a combination of any or all of the above factors. There may also be other factors that could have a dampening effect on cash out signals, but which have not been identified here.

NGET's reserve contracts

3.10. The holding of reserve contracts by the SO is one tool which it uses to balance the system in real time. NGET tenders for reserve which it can call on at short notice to increase generation (or decrease demand) in the event of the system being short.

3.11. When NGET exercises these reserve contracts, the offers it accepts will generally be at a discount to the price the generator would otherwise offer in the balancing mechanism because reserve contracts include an option fee element and an agreed offer price. This option fee can be thought of as an advance payment made for the generator to compensate it for making itself available to NGET as required rather than generating or participating in the BM. Although option fee contracts do feed through into final cash out prices, they are spread across every day of the year.

3.12. The CORWG analysed the method for allocating these reserve option fees, and concluded that under the current arrangements these costs were not well targeted in the sense of being primarily allocated to the periods when reserve is actually used. In addition, as stated above, when reserve is utilised, NGET will pay an agreed (in all likelihood discounted) rate to the reserve-contracted generator. This will appear as a low priced offer in the BM. These cheaper offers will displace potentially more expensive offers from generators that are not contracted to provide reserve and may not accurately reflect the total cost of procuring the reserve if the option fee is not properly allocated.

3.13. The allocation of reserve option fees and the associated lower accepted offer prices when reserve contracts are utilised could therefore potentially reduce the tendency for average prices to tend to marginal. Analysing the correlation between NGET's utilisation of reserve and the periods in which cash out

signals may be dampened could provide evidence on the extent to which the holding of reserve contracts dampens the signal given by the cash out price.

Repricing of bids and offers

3.14. When bids and offers are accepted by the SO within the BM, the Balancing Mechanism Unit (BMUs – individual generation units and supply points that participate in the BM) which has submitted the bid or offer accepted, will receive payment for the amount it has placed for that bid or offer. One measure of the strength of signals provided by cash out prices is the frequency with which market participants reprice their bids and offers in accordance with market conditions in each period. Analysis of the frequency with which BMUs reprice in response to changing market conditions and overall market length could provide evidence on the magnitude of barriers to responding. Such barriers may include:

- transaction costs – e.g. the costs of continuously monitoring prices and system conditions in real time and submitting bids and offers;
- information asymmetries– market participants do not have access to the same information on system balance as NGET or may not be able to access it as quickly as NGET; and
- lack of confidence in the signals –participants may incorrectly think that high priced energy actions are for system rather than energy balancing reasons.

Tagging

3.15. As outlined in Chapter 2, the objective of 'tagging' is to leave the NIV stack composed only of actions taken by NG to resolve energy imbalances. It aims to remove all actions taken for system balancing reasons, e.g. constraint management, frequency support etc. However, to the extent that the tagging mechanism does not perfectly target system trades for removal, the NIV stack (and hence the cash out price) will not reflect the costs NGET incurred in balancing supply and demand on the system. When system trades are

included within energy imbalance charges they weaken the accuracy of the cash out signals, although this effect could be in either direction i.e. they could lead to cash out prices that are too high or too low relative to NGET's energy balancing costs.

Average versus Marginal Derivation

3.16. As explained in Chapter 2, economic theory suggests that the average cash out price should tend towards the marginal price. To the extent that cash out prices calculated based on average prices do not currently tend towards the marginal price, particularly at times of system stress, then signals and incentives would be strengthened by the modification proposal. Indeed, as market participants only currently face an average cash out price, the lack of a marginal cash out price may make it more difficult to determine what the price of the marginal plant will be at times of system stress. Consequently, some market participants are not be aware of the price of the marginal accepted bid or offer.

3.17. On the other hand, if the current average prices do tend towards the marginal price, in particular at times of system stress, the benefit of modification proposal P194 is likely to be negligible. It would also tend to indicate that market participants have sufficient information to reprice their bids and offers to reflect their expectation of the marginal price.

Interactions with the gas market

3.18. If the current electricity cash out arrangements fail to provide the correct signals at times of system stress, weaker signals in the electricity market relative to the signals that exist in the gas market could give rise to distortions. If, for example, gas fired generation is able to respond to system shortages in both markets, it may respond to shortages in the gas market as a priority by reducing generation or not generating at all. Such an action could require the electricity SO to take more expensive offers to resolve imbalances. If the decision by the gas fired generators was based on disparities in the cash out arrangements between the two systems rather than on market conditions (i.e. differences

between the price of gas and electricity), this could reduce security of supply and increase the costs of balancing the electricity system. However, such interactions are complicated as the imbalance price is applied to participants' net imbalance over the course of a day in gas but to its half-hourly imbalances in electricity.

Impact of modification proposal

3.19. It should be noted that the modification proposal only directly seeks to remedy one of the four principal factors identified above (see paragraph 3.8) as possibly affecting the signals provided by the cash out price, namely any dampening of the signals as a result of the current average derivation. However, it may have implications for the other three factors and it will be important to identify any linkages between the derivation of the cash out price and the other factors described above. It is also necessary to consider any wider impacts that modification proposal P194 might have, for example on competition and the environment.

Impact of modification proposal P194 on factors that may be dampening cash out signals

3.20. In considering the impact of modification proposal P194, it is key to consider its effects on the factors discussed above in respect of the dampening of cash out signals, i.e. NGET's reserve contracts; repricing of bids and offers; tagging; and average vs marginal derivation.

NGET's reserve contracts

3.21. Analysis set out in Chapter 4 tries to assess whether modification proposal P194 would have an effect on any dampening of cash out prices caused by NGET's use of reserve. A more marginal cash out price, as is proposed under P194, should provide market participants with more information on the marginal price of balancing in each period. This may encourage greater participation in the BM since parties will be more confident of raising the prices of their bids and offers to a level close to the marginal cost. More bids

and offers in the BM should in turn reduce NGET's requirement to contract for reserve. Finally, if reserve offers are priced lower than other offers, then it is likely that they would be excluded from the cash out price calculation under modification proposal P194, thus removing any impact they may currently be having.

Lack of repricing of bids and offers

3.22. As explained in paragraph 3.21 above, a more marginal cash out price might be expected to lead to more participation in the BM. Under modification proposal P194, BMUs will continue to be paid as bid / offered for any bids and or offers accepted within the BM. The improved information on marginal costs that would result from modification proposal P194 might also increase the frequency with which bids and offers are repriced, since it may encourage parties to be more active in trying to price near the marginal price. Under the average pricing methodology, parties may choose to price near their own marginal cost to avoid missing out on their bid / offer being accepted at a profitable price, because they have incorrectly forecast the marginal cost.

Tagging

3.23. We have examined whether modification proposal P194 would alter the impact of tagging on the cash out prices and the tendency of the average price not to tend to the marginal price. The smaller volume of actions from which the cash out price would be derived under modification proposal P194 is likely to mean system actions are included in fewer periods, but have a larger impact on the price when they are included. In Chapter 4, we test the materiality of these potential impacts.

Average versus marginal

3.24. The potential benefit from the Modification Proposal will depend on, among other things, the extent to which average prices already tend to marginal prices.

Impact on NGET's SO costs

3.25. The weaker the signals that apply to market participants in relation to energy imbalances, the weaker the incentives that will exist for participants to balance their own positions by contracting ahead. Therefore, weaker signals are likely to result in a larger role for the SO in respect of its residual energy balancing role. This will increase the costs of the SO since it will have to procure more reserve and/or potentially buy more expensive energy to provide the volume of flexible capacity that balancing the system would require. This will reduce the efficiency of the electricity market as a whole since some of the costs and risks are taken away from those who create them, and are best placed to manage and mitigate them.

3.26. If the proposal results in more appropriate signals about the costs of energy imbalances, market participants will have stronger incentives to balance their own positions. This will increase the efficiency of the electricity market as a whole and reduce SO balancing costs as most market participants are likely to be able to balance their own portfolios at lower cost than the SO during most periods.

3.27. Moreover there could potentially be an incentive on market participants to hold long positions in order to reduce exposure to the SBP if the incentives on market participants are sharpened through the introduction of a more marginal calculation of cash out prices. This could (in the short term at least) also increase the costs of balancing to the SO, because it will effectively be selling more energy by accepting bids to bring the system back into balance.

3.28. However, the extent to which system length does increase as parties seek to avoid exposure to high SBPs can be seen as the market providing its own reserve, which should, at least in the medium to long term, displace (i.e. reduce by a similar amount) NGET's requirement to hold its own reserve. This may give rise to lower overall costs of balancing.

3.29. NGET considers that rather than necessarily increasing system length, a more marginal cash out signal will encourage participants to appropriately cover

their contractual positions in periods of system stress, which account for a relatively small number of the overall settlement periods in a year.

3.30. In assessing whether the proposal results in stronger signals in relation to energy imbalances, it is therefore necessary to assess what impact the change to a more marginal derivation of cash out prices is likely to have on SO costs particularly at times of system stress.

Impact on market participants' costs

3.31. The modification proposal will sharpen cash out signals to the extent that the weighted average price does not tend to the marginal price at present. If the modification proposal does sharpen the signals to market participants, it could be expected to impact on costs to market participants facing imbalance in certain periods. However, decreased SO costs would be expected to reduce costs incurred by market participants as a whole.

Impact on market participants' response

3.32. The benefits of stronger signals and incentives rely on the ability of market participants to respond. Market participants could be expected to seek to mitigate any increase in imbalance costs by:

- engaging in more active management of their generation/customer portfolio or improved trading and contracting ahead with other parties;
- reducing the likelihood of imbalance (e.g. by investments to improve the reliability of their plants, improved demand-forecasting and/or contracting for more flexibility and demand-side response); and/or
- using risk mitigation such as financial hedging instruments or by managing its overall physical portfolio so that they are long overall (i.e. generating more than their contracted position).

3.33. Some market participants indicated in their responses to the draft modification proposal that they are already doing everything they can to address

imbalances. As such, they do not consider that they could respond to any increased signals relating to imbalance that would arise from the implementation proposal. The ability of market participants to respond to stronger signals therefore needs to be considered when assessing the costs and benefits of the modification proposal.

Interactions with the gas market

3.34. A change to the arrangements in electricity so that the costs to the system of resolving electricity imbalances were accurately signalled to gas market participants (as with other electricity market participants) could assist in providing greater economy and efficiency and also security of supply. However, evidence that the interactions between cash out prices can give rise to perverse incentives on gas fired generators that do not reflect underlying market conditions in the two markets may not necessarily be a reason to change the electricity arrangements. The cause of the problem may be that gas has a long balancing period and uses a marginal derivation of its main imbalance price, so that a very small high priced trade mid-way through the day can set the imbalance price for the whole day even if by the end of the day the gas system is not under stress. If this is a problem the solution may be to change gas cash out arrangements, not electricity. Furthermore, the different cash out periods in gas and electricity are always likely to create different incentives in the two markets. However, if these balancing periods appropriately reflect the physical realities and SO balancing costs of the two markets, it may not be appropriate to adjust either set of arrangements.

Competition and distributional impacts

3.35. Cash out prices may have an effect on the level of competition in the electricity market. Higher imbalance charges that do not reflect market conditions could constitute a barrier to entry. However, higher charges per se do not constitute a barrier to entry in the pure economic sense since they will be incurred equally by incumbents and new entrants (in proportion to the level of their imbalance). It could be argued that a signal which more accurately reflects the

costs of balancing may attract more entry because it provides more certainty (i.e. less risk) in terms of forecasting costs. On the other hand, the short-term uncertainty created by changing the cash out arrangements could have adverse effects on all players.

3.36. A change in the derivation of the cash out price may have a redistributive effect, since the total volume of imbalance payments may change under the modification proposal, which would in turn alter the amount redistributed through RCRC. Because this 'pot' is distributed in proportion to the total credited energy i.e. metered volumes, in a period, a larger RCRC would benefit those who produce/consume large volumes of electricity relative to those who have a large imbalance (and have thus contributed more to the pot). To the extent that these two groups are composed of different participants, there will be a redistributive effect. This section considers which parties may be expected to benefit more, and which may benefit less, from a more marginal cash out mechanism.

Effect of dampened signals

3.37. As has been previously discussed, the current cash out signal is based on the average of accepted bids (and offers), and participants in the BM may find it hard to know what the marginal bid (or offer) was. Accordingly, they may find it harder to increase their profits by repricing their bid/offer to the likely marginal bid/offer. The difficulty of judging the marginal bid/offer may dissuade some generators and suppliers from participating in the BM. Lower liquidity, in the form of a narrower range of bids and offers, would, other things being equal, reduce competitive forces in the market, e.g. through less downward pressure on prices.

Impact of modification proposal

Liquidity

3.38. As described above, a cash out signal that better reflects marginal bids and offers could increase participation in the balancing market. It should also

provide stronger incentives for market participants to try to balance their positions ahead of gate closure. Improved participation in spot and forward markets would result in increased liquidity and could include more active participation (including on the demand-side), thereby increasing the overall range of balancing tools available to NGET and increasing competitive pressures. Greater liquidity could also help support the development of more actively traded financial products.[25]

Gaming

3.39. Ofgem has previously expressed concerns[26] that more marginal forms of pricing may increase the opportunity or incentive of generators to 'game' the arrangements. As a more marginal price means that the overall cash out price will generally be calculated on the basis of a smaller number of trades, there is a concern that this could increase the impact that a high-priced trade that did not reflect underlying market conditions would have on the overall cash out price. High cash out prices could feed through to higher day-ahead and forward prices or result in net cash flows back to generators through the RCRC, both of which could increase profits for generators. The concern is that, under modification proposal P194, market participants may try to manipulate market prices through small volume and high priced offers, particularly at times of system stress.

Distributional impacts

3.40. One of the key objectives of cash out arrangements is that, in order to provide incentives and signals, the costs of resolving energy imbalances are faced by those market participants that caused those costs to be incurred. A more marginal price could, on average, mean that there would be a higher buy price (where the system is short) or a lower sell price (where the system is long) for being out of balance. This may impact certain classes of customer or generator

[25] This would have the benefit of reducing the cost or enable the development of more sophisticated tools for market participants to hedge against market risks.
[26] For examples of these concerns please refer to Ofgem's decision letters in respect of BSC Modification Proposals P135, P136 and P137.
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to a greater or lesser extent. These redistributive effects may be appropriate if it means that the resulting change in cash out prices better distributes the costs of resolving imbalances to those causing them.

3.41. Hence, to the extent that cash out has beneficial redistributive effects, generators and suppliers more efficient at balancing will be able to compete more effectively if they are not exposed to SO balancing costs imposed by others, and less efficient generators and suppliers face the costs they impose on the system instead. In addition, the increased incentives on participants to buy out even small volumes of imbalance could result in more liquidity in this close to real time market. At present NGET pays suppliers of balancing power on a 'pay as bid' basis, and charges demand either at a price approximating the average of accepted bids (the main price) or at a price derived from a market price based on short term energy trades on the forwards and spot markets (the reverse price). The money paid to providers of balancing power and users of it are roughly equal. If parties are cashed-out at a more marginal price as a result of the proposal, NGET would receive more from consumers of balancing power than it pays to providers (who would still be paid as bid), resulting in a greater surplus that has to be passed back to industry through RCRC. As the monies passed back are allocated based on metered volumes, this means that larger users obtain higher payments, whereas smaller parties obtain lower amounts. Therefore, if a more marginal cash out regime increases the RCRC sums, this could have redistributive impacts.[27]

Security of supply

3.42. The sharpness of the cash out signal determines the extent to which market participants offer flexibility, in the form of bids and offers, to NGET. The more flexibility NGET has to balance the system, the more protection it has against, e.g. plant loss or sudden changes in demand, which could otherwise result in a loss of supply.

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[27] In addition, respondents to Elexon's assessment consultation have noted that higher cash out prices would entail larger credit cover requirements and could again have a relatively larger impact on smaller players (relative to their turnover).
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3.43. Cash out prices should also feed into prices on the forward electricity markets, which signals the need to invest in new plant. The more accurately cash out prices reflect the costs of balancing the system, the more accurate forward prices should be in signalling expectations of future supply and demand conditions.

Effect of dampened signal

3.44. Dampened signals may have an impact on security of supply in both long term investment timeframes and, more directly, in the short term.

Short term effects

3.45. If inaccurate signals lead to a reduction in the number of bids and offers in the BM, NGET as SO has fewer options for balancing the system, which increases the chances of supply interruption at times of system stress. In its response to the Assessment Procedure Consultation in respect of modification proposal P194, NGET suggests that if the cost of buying the marginal unit in the forward market is greater than the likely exposure from (dampened) imbalance prices then economic rationale would dictate that the marginal unit will never be bought in the forward market. The distortion of the signal of energy scarcity could lead to a perverse incentive where, on days of system stress, market participants would find it economically beneficial to go short into the BM. This could threaten security of supply in those periods.

Long term effects

3.46. To the extent that imbalance prices influence forward prices, weak or inaccurate signals may cause investors to make incorrect investment decisions. In particular, investment in new and/or existing plant could be delayed, potentially leading to supply shortages.

Impact of modification proposal

3.47. If the modification proposal can be demonstrated to result in more appropriate pricing signals at times of system stress there are potentially long and short term effects on security of supply.

Short term effects

3.48. In the short term, improved signals and market response could enhance incentives on market participants to balance and to generate sufficient trading activity to enable shortfalls of supply relative to demand to be resolved. The SO has indicated that such increased trading is important for security of supply.

3.49. However, one potential consequence of a more marginal cash out could be that generators would self insure by holding back some output for use at short notice. It is suggested that this would be undesirable from a security of supply perspective.

3.50. One concern in relation to security of supply is whether participants already respond to price signals at times of system stress to the maximum extent that they are able to do so. If marginal cash out imposed much greater costs on those market participants, this could have security of supply impacts if a large proportion of generation chose not to generate from plant to avoid risk of high cash out prices in the event of generation failure. Consequently, the precise impact of modification proposal P194 on security of supply will very much depend on the likely market response(s).

Long term effects

3.51. In the long term, sharper pricing signals may influence the investment behaviour of generators (e.g. investing in existing plant to improve reliability, and/or investment in new more responsive or reliable plant) by providing signals to market participants via the forward market as to the value of that plant relative to other forms of generation. It may also influence decisions regarding the closure or refurbishment of existing plant and the levels of maintenance to undertake.

3.52. On the demand side, sharper signals could provide stronger incentives on market participants to develop more flexible contracting and/or more responsive demand, which would reduce the potential for unplanned interruptions to supply. In addition, the proposal could improve incentives on market participants to invest resources to improve their demand forecasting techniques. If the proposal was effective in influencing behaviour significantly, this could result in market signals providing a better indication to parties of the value of holding a more reliable and responsive portfolio of generation, which would benefit security of supply.

Impact on the environment

3.53. Concern has been expressed that the proposal could damage the environment by increasing the risks faced by renewable generators. If renewable generators were less able to predict their output they would face greater risks than non-renewable generators who could predict their output and manage this. Evidence suggests that, other than wind generators, renewable forms of generation are no less predictable than thermal plants over short timescales[28] and hence they should not be at any disadvantage with regard to balancing. In respect of wind, there is evidence to suggest that over short-term timeframes its predictability improves considerably.[29]

3.54. However, even if predictability does vary between particular types of generation, this is not a reason to reject the proposal. If certain generation technologies are less reliable than others it is appropriate that they are exposed to the costs of managing this. They can either manage their exposure by contracting with the demand side or other more reliable generators. Or they can pay the cash out price that reflects the cost to the SO of managing the risk

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[28] Report to the DTI on the Review of the Initial Impact of NETA on Smaller Generators, Ofgem, August 2001.

[29] See for example: "Variability of wind power and other renewables – management and option strategies", International Energy Agency, June 2005. In this report, it is noted that in countries that have invested in forecasting, such as Germany, the forecast error of only 2% have been achieved at the hour-ahead stage. The report also considers the benefits of "distributional" effects, such that a generator with a wider portfolio of wind farms would see far less variation in its aggregate output than if an individual wind turbine was considered in isolation.

for them. It is important, as with other generators, that they are exposed to the full cost so that they too can assess the costs of managing the risk themselves or letting the SO manage them.

3.55. As has already been indicated, a possible consequence of implementing the modification proposal could be that some market participants would adopt longer positions to ensure that they are not exposed to the risk of an increased SBP. As stated above, whether there are increased incentives on market participants to hold long positions will depend on the number and type of periods in which the imbalance signals will be strengthened as a result of modification proposal P194. Another way that market participants could manage the risk would be to part-load some or all of their plants so that they could replace, at short notice, the output of any of their plants that happened to trip. Typically, the efficiency of plants that are part-loaded is lower than when they are operating at full output so that their fuel use and emissions is higher for each unit of electricity generated. Hence, any rise in part-loading of plant could have adverse environmental consequences.[30]

3.56. Parties with a wider portfolio of generating plant would generally be more able to part-load one or more of their plant; whereas single site generators, for example, are unlikely to have the option of reducing output to provide reserve. In addition, different types of power station vary significantly in their flexibility, and hence are more or less suitable for part-loading. For example nuclear power needs to run at full capacity for safety reasons, whereas coal plant can be turned up or down relatively quickly once it is running.

3.57. Some part loading is necessary in order for parties to be able to respond to system changes. However, incentives exist through the EU Emissions trading scheme to minimise the possible environment cost of part-loading. Equally, the increased incentives on market participants to balance could reduce the

[30] For example, data available on a modern gas-fired plant operating at 100% could have a net efficiency of 58%. Based on these figures part loading a CCGT to say 75% load would decrease the efficiency by just under 2 percentage points and increase the NOx and CO2 emissions per unit of electricity by a similar amount. Part loading to 50% would have a more marked effect - decreasing efficiency and increasing per unit emissions by approximately 5 percentage points.

amount of reserve that the SO needs to hold, which is also achieved by part-loading plants, which could benefit the environment. There would only be an impact on the environment to the extent that modification proposal P194 alters the aggregate level of part-loading.

Risks and unintended consequences

3.58. In addition to the key issues identified above, Ofgem considers that modification proposal P194, if implemented, could potentially have an impact on the tagging mechanism and on the environment.

Tagging mechanism

3.59. As stated above, the current cash out arrangements apply certain rules to remove system balancing actions from the cash out calculations through the tagging mechanism. They have the objective of ensuring that the cash out price only reflects the costs to NGET of resolving energy imbalances. As stated above, the tagging mechanism does not always remove all system balancing actions, particularly constraint actions, and this could be affecting cash out signals.

3.60. Moving to a more marginal pricing calculation could exacerbate the impact of system trades on the energy imbalance price, because system actions are likely to be expensive, and could, if not excluded, fall within (and form a significant proportion of) the most expensive 100 MWh used to calculate the cash out price under modification proposal P194.

3.61. The inclusion of system actions within imbalance charges could disadvantage market participants facing imbalance charges. This is because those parties will face potentially high costs of alleviating system constraints which are not attributable to the imbalance position of the affected parties.

Costs of implementation

3.62. Elexon has estimated the central costs of implementing this proposal and the costs for each market participant. We do not propose to produce our own estimates of implementation costs, but have sought to verify with Elexon its estimates.

Summary

3.63. This chapter has outlined the main areas that modification proposal P194 could affect. The next chapter seeks to assess the likely costs and benefits associated with modification proposal P194 in relation to each of the areas identified. Where possible or appropriate, it seeks to quantify the costs and benefits.

4. Costs and benefits of the proposal

Introduction

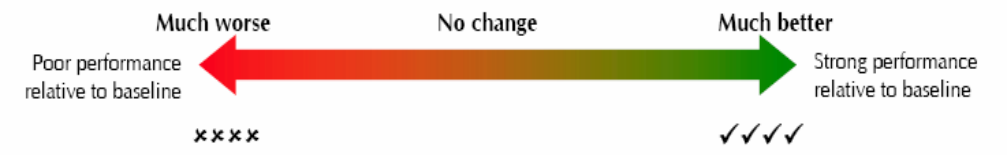
4.1. Wherever possible and appropriate, Ofgem has sought to quantify the effect of the impacts that would be likely to result from the approval of modification proposal P194. Our baseline for comparison has been the current cash out mechanism and most of our analysis has concentrated upon differences that would have arisen had modification proposal P194 been in place during the period 1 April 2004 to 30 June 2005. This analysis was originally undertaken in Autumn 2005 by NGET for the CORWG, which explains why the analysis does not include data up until the present time. Where data are available, and where Ofgem considered more recent data may have a material impact on our conclusions, analysis has been supplemented with data from more recent periods.[31]

4.2. Not all of the issues that Ofgem considers it necessary to take into account in assessing the impact of modification proposal P194 can be easily assessed via quantitative analysis. In some instances, this is because it is not possible to isolate the impact of the issue being considered from the impact of other factors with the data available. In other instances, it is because available data or possible analysis would not allow Ofgem to draw meaningful conclusions. For these issues, Ofgem has included a qualitative discussion of the likely impact that would result from implementing Modification Proposal P194.

4.3. Where Ofgem has made a qualitative assessment, the assessment presented in this chapter is expressed as a rating that compares the performance of the proposal against the current baseline. The spectrum of ratings used in the assessments in the remainder of this chapter is illustrated in Figure 2.

[31] In most instances this is simply to extend the analysis so that there is a larger (more statistically significant) sample of information on which to base the analysis. Where this is not the case, this is explained in the text.

Figure 2: Interpretation of qualitative assessment



4.4. As a result of the analysis that it has carried out, Ofgem has identified a number of positive and negative impacts that would arise from implementing modification proposal P194. Consequently, Ofgem has had to balance these competing effects in assessing the likely overall impact of implementing Modification Proposal P194 on the wholesale electricity market.

Economy and Efficiency

4.5. This section focuses on what impact modification proposal P194 might have on cash out prices, the overall level of participants' imbalance exposure and NGET's balancing costs. In undertaking this analysis, we have considered the direct effects of the modification proposal on the derivation of the cash out price, as well as possible changes in behaviour by participants in response to the implementation of modification proposal P194.

Are existing cash out prices providing sufficient signals?

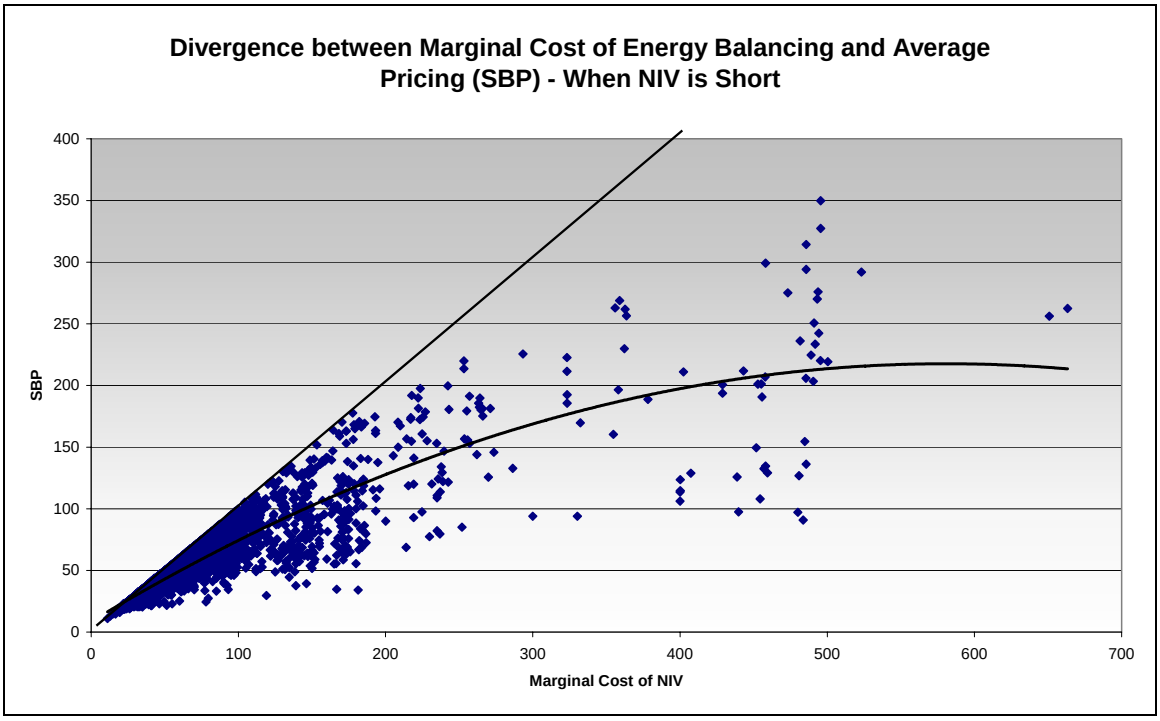
4.6. The modification proposal has to be assessed against the arrangements currently in place. As explained in Chapter 3, it is necessary first to examine the signals that are provided under the current methodology, and whether these signals are being dampened.

Does the average price tend to the marginal?

4.7. We start by considering whether the average cash out price does indeed tend towards the marginal price as economic theory suggests under a defined set of assumptions (see Chapter 2). In order to examine this, NGET carried out analysis to show the correlation between the marginal cost of resolving NIV when the system is short and the outturn (weighted average) price for 2004/5. If average prices were tending towards the marginal cost of resolving the

system shortage, the observations would cluster around the straight diagonal line in Figure 3 below. However, the chart clearly demonstrates that this is not the case.

Figure 3: Comparison between marginal and average costs of balancing energy

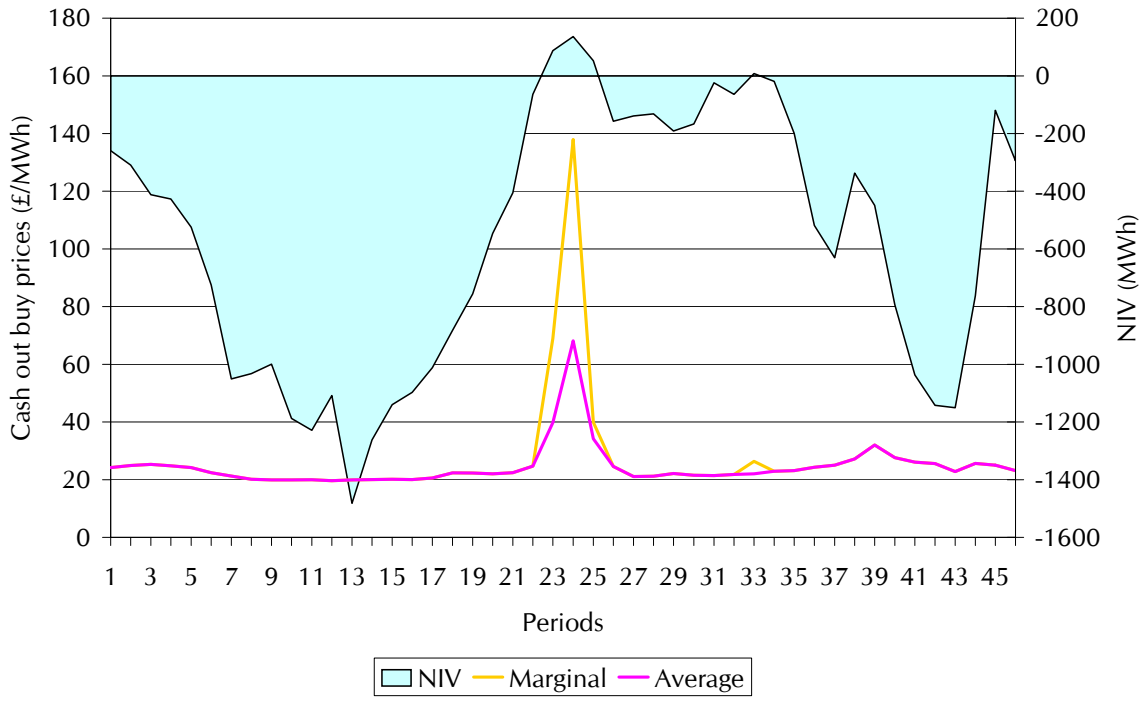


Source: NGET

4.8. In a number of periods where SBP was relatively low, the weighted average price was at or close to the marginal cost. However, as prices rise, there is an increasing divergence between the two figures, as demonstrated by the curved trend line. The analysis was only carried out for periods when the NIV was short, since NGET is less concerned about periods when the NIV is long.

4.9. The analysis suggests that there is a particular divergence between average and marginal costs of balancing in certain periods. Assuming that SBP was higher at periods of system stress, (i.e. when NIV was particularly short), the analysis suggests that the divergence between average and marginal costs of balancing is most marked at periods of system stress. An illustration of this, for a set of specific balancing periods on one day, is shown in Figure 4.

Figure 4: Comparison of marginal and average cash out buy prices on 27 March 2005

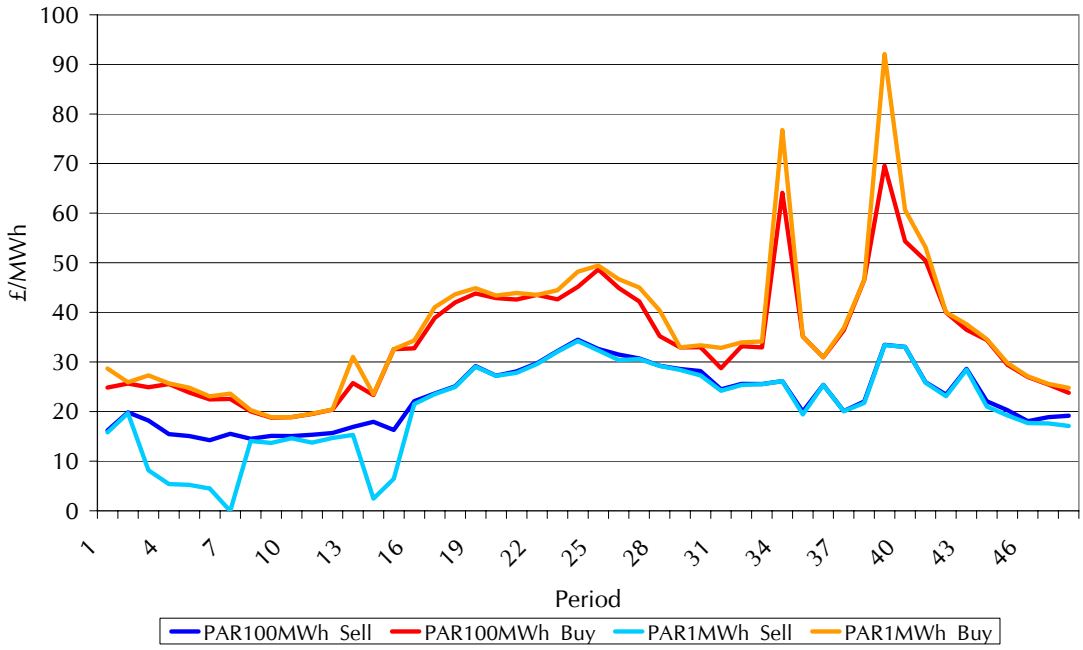


Source: NGET

4.10. Figure 4 clearly shows that in periods where the system is long (and NIV negative), the marginal and average prices are almost identical, whereas in period 24, where the system is under stress and the NIV positive, the marginal buy price would have been significantly higher than the weighted average price – around £140/MWh versus £65/MWh. This suggests that a marginal derivation of cash out charges would provide sharper economic signals to balance in such periods.

4.11. As explained in Chapter 2, modification proposal P194 would not set cash out prices solely on the cost of the marginal trade, but on the weighted average of 100 MWh of the highest priced offers (where SBP is the main price) or lowest priced bids (where SSP is the main price). Figure 5 compares, in overall terms, the difference of a fully marginal methodology to the PAR100 (i.e. where the main imbalance price is based on a weighted average of the top 100 MWh in the NIV) approach incorporated in modification proposal P194.

Figure 5: Comparison of marginal and PAR 100 based on sample periods[32]



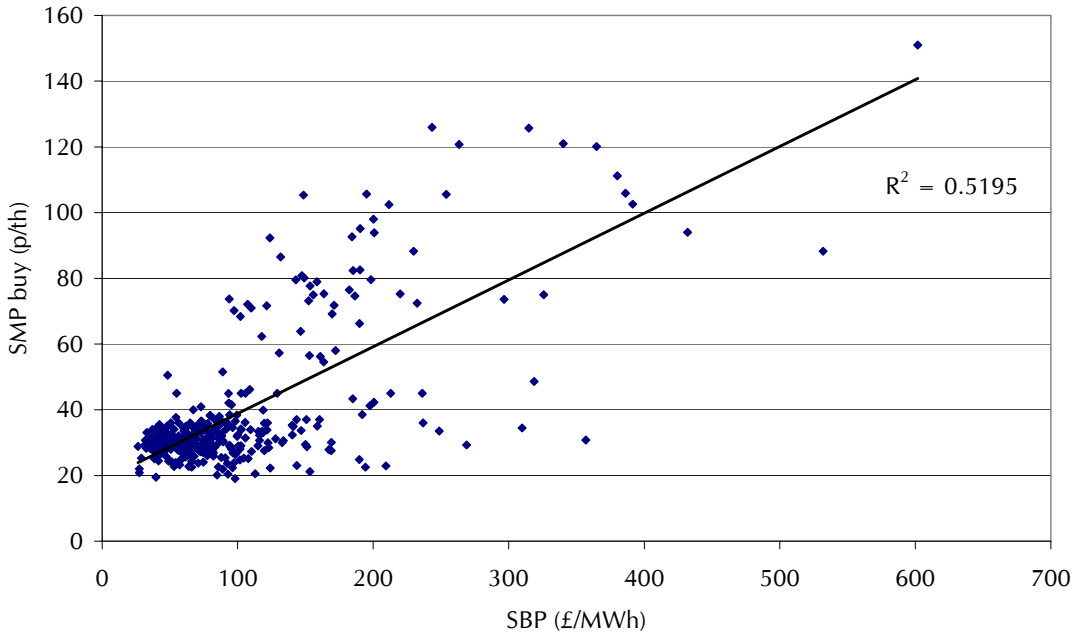
4.12. Analysis later in the chapter looks at the difference in cash out prices that would result from moving to a PAR100 methodology. Although the above chart does not fully show the differences between PAR100 and a fully marginal methodology, due to averaging across days, it would appear that in broad terms the PAR100 follows closely the marginal price.

Interactions with gas cash out arrangements

4.13. As stated in Chapter 3, if the current cash out arrangements fail to provide the correct signals at times of system stress, the weaker signals in the electricity market relative to the signals that exist in the gas market could give rise to distortions. Figure 6 shows the correlation between the highest daily cash out prices in the electricity market and the SMP buy price in the gas market for all days in 2005.

[32] This chart is based on 12 days selected by the CORWG as representative days from data from April 04 – March 05, including different seasons and Triad days during this period.
BSC modification proposal P194 'Revised Calculation of the Main Energy Imbalance Price', Impact Assessment

Figure 6: Correlation between cash out prices in electricity and gas



4.14. Figure 6 shows some degree of correlation between cash out prices in the electricity and gas market. Nevertheless, there are periods when the cash out prices in electricity and gas are not well correlated (as indicated by the spread in the data). In some cases this may be because supply conditions in one market are relatively benign, whereas supply in the other market is quite tight. A key issue is what happens when the gas market requires a response in the electricity market from gas fired generation. This issue is considered in the section below (paragraph 4.85 and Appendix 4).

What factors may be dampening signals?

4.15. As set out in Chapter 3, Ofgem has identified, following consideration of the FMR, the views of respondents to the DMR and assessment consultation and the work of CORWG, four factors which may be dampening the cash out signals. These are:

- NGET's reserve contracts;
- lack of repricing of bids and offers;

- the tagging mechanism; and
- the average calculation of cash out prices.

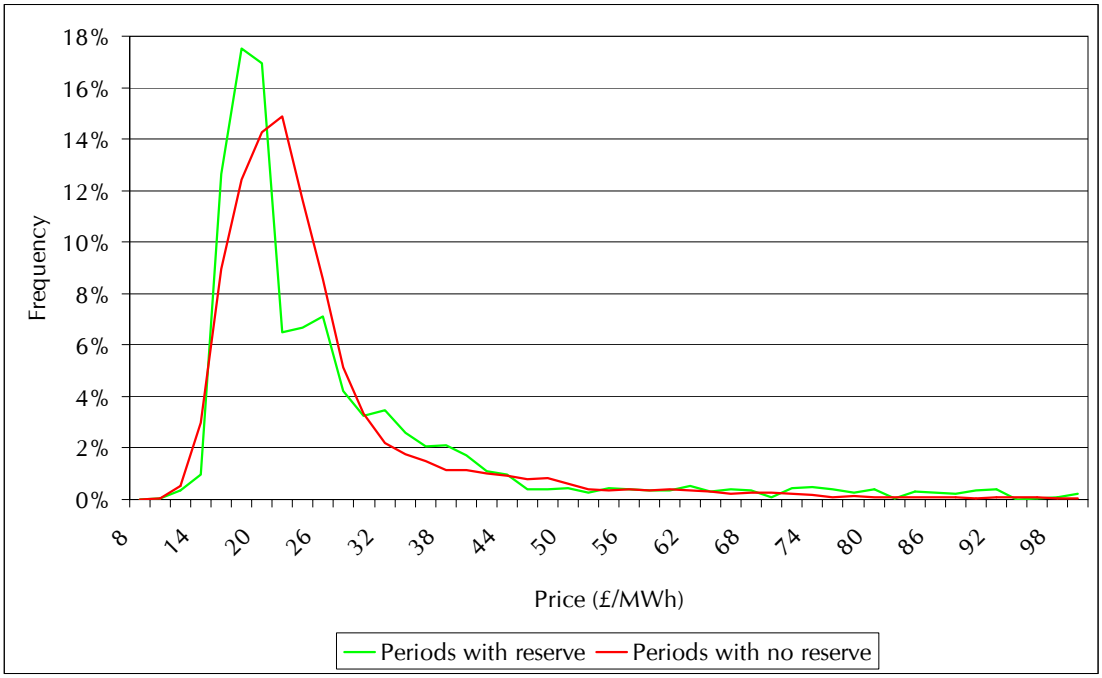
4.16. We present our analysis in respect of each of these factors below.

NGET 's reserve contracts

4.17. In order to assess whether NGET's allocation of the costs of reserve contracts has a dampening effect on cash out prices as would be expected, we have carried out analysis to show the difference in prices between those periods where standing reserve is called upon and those periods where it is not.

4.18. Using data supplied as part of the CORWG process, Figure 7 plots for 2004/05 the distribution of SBPs under the current cash out mechanism. SSPs are not considered since NGET is unlikely to call on reserve when the system is long. The prices are displayed separately for periods where NGET called on reserve and periods where it did not. Over the course of the year, NGET utilised standing reserve during approximately 11% of periods, two thirds of which were during peak periods. In those periods when standing reserve was utilised, the average volume called upon was 57 MWh, or approximately 7% of the average volume of actions accepted (800 MWh).

Figure 7: Distribution of SBP in periods with and without use of reserve (Average pricing)



4.19. Under the current cash out mechanism, there is a concentration of periods with prices in the range of £15-30/MWh. In periods where no reserve is called by NGET, prices are focused around the higher end of this range, whereas they are mostly at the lower end for periods where reserve is used. This analysis suggests that the calling of standing reserve by NGET may have a slight dampening effect on cash out prices. However, it does not provide conclusive proof of such an effect because there may be other factors affecting cash out prices in the periods when NGET utilises reserve which have not be taken into account.

Repricing of bids and offers

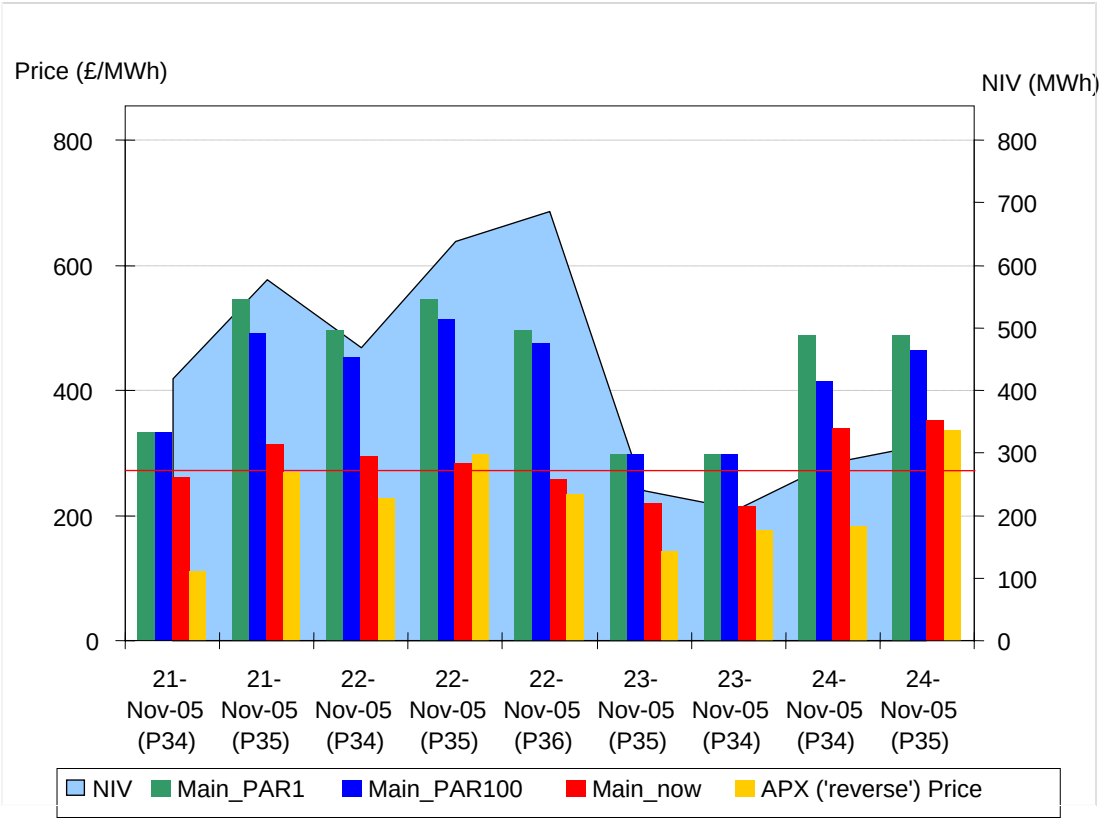
4.20. If market participants are not particularly pro-active within the BM in that they fail to reprice bids and offers in response to changes in the likely cost of the marginal trade then average prices are unlikely to tend to marginal. NGET identified the peak periods on 21-22 November 2005 as a recent example when the market was short (shown as a positive NIV in Figure 8 below) and,

over this period, the cash out prices (shown as Main now) failed to tend towards the marginal price (shown as PAR_1[33]).

4.21. Chapter 3 noted however that the absence of marginal pricing may itself act to reduce the extent of repricing as under the current calculation market participants cannot rely on the main cash out price to inform them of the marginal price. As market participants are paid the price they have bid (offered) within the BM for accepted bids (offers), and not the marginal price of the trade, the clearer indication of the marginal price may cause market participants to reprice more frequently to set their price near to the marginal price in subsequent periods. It therefore seems likely that if modification proposal P194 is introduced, this might improve the incentives on BMUs to reprice.

[33] Namely the last 1 MWh offer in the NIV.

Figure 8: Comparison of average versus marginal prices over peak periods: 21 - 24 November 2005



Source: NGET

4.22. Figure 8 tends to support the conclusion that individual BMUs are not changing their offer prices posted in the BM in response to changes in the direction and length of the system.

4.23. Ofgem undertook further analysis, presented in Table 2 below, which considered offer prices placed in the BM on these two days.[34] As suggested above, the results identify that when the system became shorter, generators failed to adjust their offer prices in the BM. For example, on 21 November 2005 the system moved from being 165MW long to 576MW short over 3 periods but the average offer price actually fell from £292/MWh to £278/MWh. A fairly similar result is shown for the 22 November 2005, although there was some increase in offer prices during the course of 22 November 2005, the offer

[34] There is some difference in the offer data owing to differences in the settlement run periods used. BSC modification proposal P194 'Revised Calculation of the Main Energy Imbalance Price', Impact Assessment

prices were not significantly higher despite a change in NIV of 400 MWh. There is also relatively limited movement in the standard deviation (suggesting that the spread in offer prices remained fairly constant over these periods).

Table 2: Comparison of market participant behaviour over peak periods on 21 - 22 November 2005

	Settlement Period					
Settlement Date	33	34	35	36	37	38
21-Nov-05						
Average offer Price	292.1	237.7	277.8	274.6	195.7	213.2
Std Dev of offer price	221.0	192.5	205.8	206.0	162.5	141.5
NIV	-164.4	419.3	576.3	297.7	342.4	445.6
22-Nov-05						
Average offer Price	160.0	217.5	215.3	232.0	242.6	248.7
Std Dev of offer price	134.8	148.8	156.6	147.9	140.2	185.2
NIV (MWh)	178.4	468.1	638.5	686.6	497.4	104.0

Source: Ofgem (Elexon data)

4.24. In order to test whether the aggregate data hides any underlying changes in individual market participants' behaviour, separate analysis was carried out in respect of individual BMUs. The result of this analysis indicated that, of the 38 BMUs active on 21 November 2005, between periods 33 and 38 only 15 per cent of them changed the offer prices they placed in the BM.

4.25. Although it is difficult to apply strong conclusions on bid-offer behaviour from such limited data, together with the wider anecdotal evidence NGET provided as part of its proposal, this analysis tends to support the view that there is

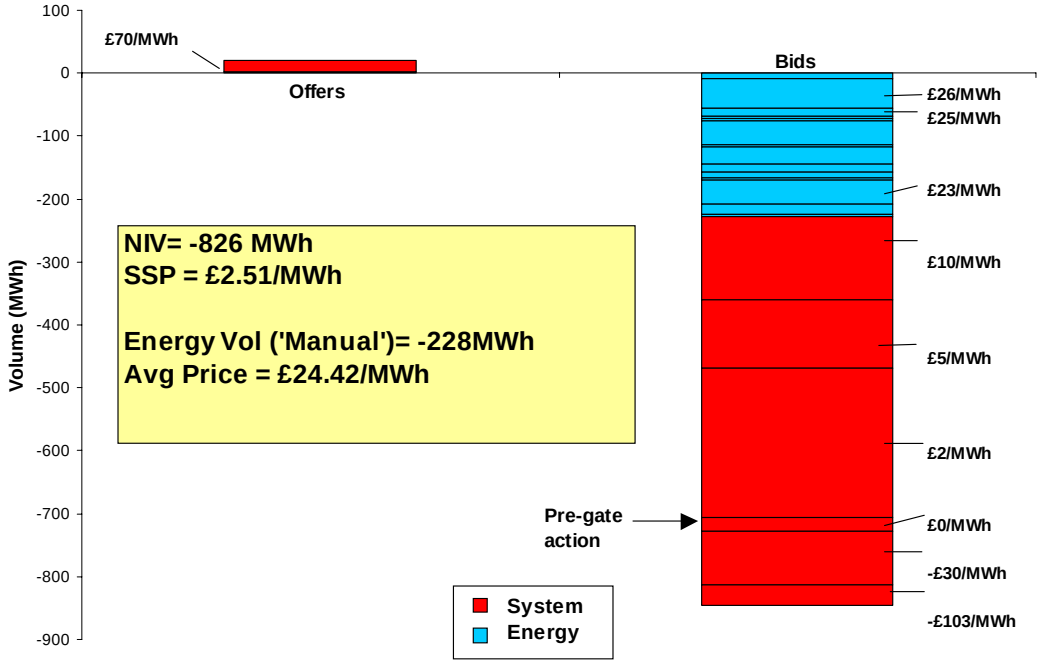
sometimes limited repricing of offer prices in response to changing system conditions. This point was also raised by a number of respondents to Elexon's modification consultation. A lack of within day repricing is, therefore, likely to explain, at least in part, why average cash out prices are not tending towards the marginal price during certain periods

Tagging

4.26. Average prices may not be tending to the marginal price because the tagging mechanism does not always perfectly target system trades for removal. As explained in chapter 2, the objective of 'tagging' is to remove system actions so that the cash out calculation is only based on actions taken by NGET to resolve energy imbalances.

4.27. Figure 9 (provided by NGET) demonstrates that system actions can in some periods form a large proportion of the NIV stack. The chart shows all the bids and offers that were accepted by NGET for settlement period 19 on 26 September 2005, after NIV tagging has taken place. The final NIV is calculated by netting off the (smaller) offer stack from the bid stack, and the main price (SSP) is the weighted average of all remaining bids.

Figure 9: Bid/Offer stack for 26 September 2005, settlement period 19



Source: NGET

4.28. The SSP in this period was £2.51/MWh, although the weighted average price of all 'energy' actions in the stack was £24.42/MWh. It is not possible to say from this chart whether there were 'energy' actions available that would have replaced the 'system' actions, and hence what the price would have been in the absence of these system actions. However, system actions do not reflect the cost of energy balancing the system, except by chance.

4.29. Cash out prices that are distorted by the presence of system trades in the NIV stack reduce the ability of market participants to analyse and forecast the cash out price in any period. If participants believe actions taken for system reasons may influence cash out prices, but are unable to predict when this 'distortion' might occur then this can create uncertainty. This is likely to make participation in the BM more unpredictable as it is harder for participants to assess what the marginal price for energy trade is likely to be. This could result in participants being reluctant to spend time and resources in this assessment and cause them to price at their own marginal cost rather than the cost of the marginal trade. This therefore could have the effect of reducing active

participation in the BM, as it creates more risk for parties. Even if market participants are attempting to price bids and offers on the basis of the marginal price of electricity imbalance, if the resulting cash out price is determined by costs of system rather than energy balancing then there will likely be a number of periods when the average does not tend to marginal.

4.30. NGET undertook further analysis on tagging, looking at the period from 1 April 2005 to 14 November 2005. One of the results of the analysis is that there is a difference in the average cash out price in periods when there were constraints compared to periods where there were not. This suggests that system trades could be impacting upon the calculation of the cash out price.

4.31. Of the 10,946 periods considered, system constraints were present in 28% of them (i.e. 3,104 periods). However, not all of these constraints would have been resolved in the BM, nor is it necessarily the case that constraint trades in the BM fed into cash out prices (the data from NGET does not reveal whether tagging successfully removed these trades).

4.32. To consider how often constraint periods were likely to have system trades in the NIV stack (i.e. how often system actions were not tagged out), Ofgem requested that NGET analyse 30 random periods where there was a constraint. Of the 30 random periods analysed, system actions were present in the NIV stack (and therefore influenced the cash out price) in 10 periods. System actions were present in the top 100MWh of the stack (i.e. the PAR100 volume) in eight of those periods.

4.33. On the basis of this small sample, system trades affected cash out prices under a PAR100 methodology in 7.6% of periods.[35] However, to the extent that additional energy balancing actions would have been required if there had been no system actions, no assumptions can be made as to whether these constraint actions displaced a cheaper alternative, since data on bids and offers

[35] An impact was detected in 8 out of the 30 constraint periods selected. Given 3104 of 10946 are constraint periods, [(8/30 x 3104)/10946] x 100 = 7.6%.
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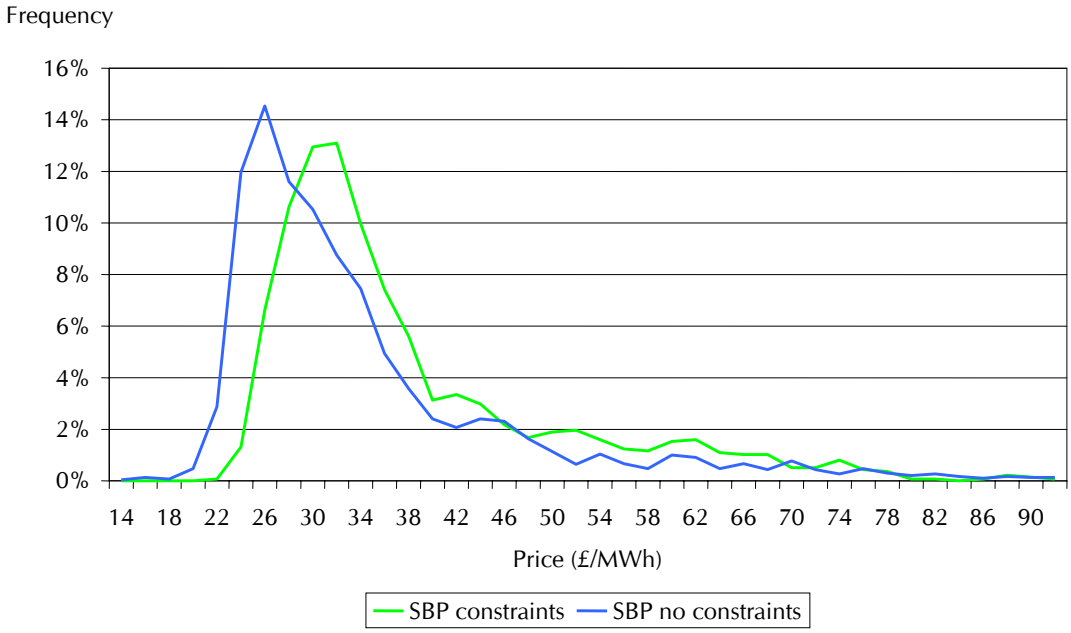
not accepted is not available. Hence, it cannot be determined whether the price would have been different in the absence of constraints.

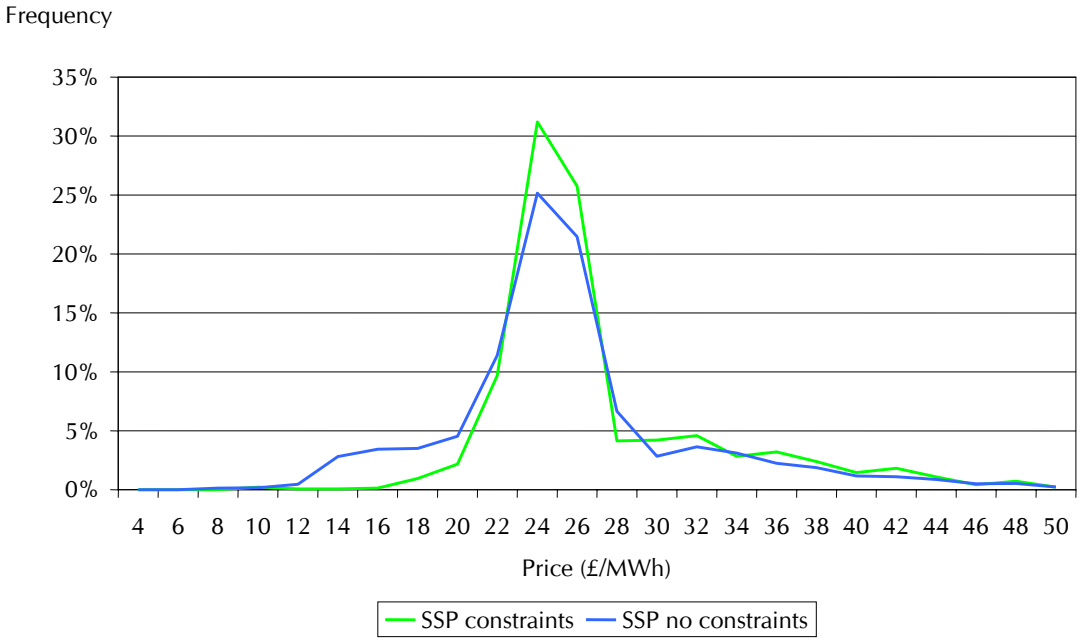
4.34. In order to examine further the effect that constraints have on cash out prices, the analysis below shows the difference in prices between periods in which system constraints are present and periods without constraints.

Figure 10: Distribution of buy prices



4.35. As might have been expected, the SSP under both the current and proposed derivation methodology was higher in those periods identified by NGET as constrained. Prices above £30/MWh occurred more frequently in constrained periods than they did in unconstrained periods, and vice versa. For example, under the current average methodology, an SBP of £34/MWh occurred in 13% of constrained periods, and only 8% of unconstrained periods, whereas an SBP of £26/MWh occurred in 7% of constrained and over 14% of unconstrained periods.

Figure 11: Distribution of sell prices



4.36. Constraints also appear to push up system sell prices in a number of periods from a range of £10 – 20/MWh to around the £25/MWh mark.

4.37. On average, the difference between SBP in constrained and non-constrained periods is £3.72/MWh (14% of the average buy price or 6% of the average peak price over this period). It is unlikely that cash out prices will include constraint costs in all periods where there are constraints. The inclusion of constraint costs in some periods however, means it is more uncertain where the marginal energy trade is and, for that reason, participants will not be able to submit BM bids for energy reasons which reflect that marginal energy trade, which means in turn that the average bids for energy would have a wider spread than would be the case if the tagging regime worked perfectly (and all market participants had perfect foresight).

Average versus Marginal

4.38. If average prices already tended towards marginal prices sufficiently there will be less benefit with the change. However, the analysis thus far suggests that this is not the case and that there may be a number of factors that are leading to the dampening of cash out signals. The proposal seeks to address this by changing the calculation of cash out prices towards a more marginal basis. The key question, therefore, is what impact modification proposal P194 is likely to have, not only directly by changing the cash out price, but also on the other factors that appear to be acting to dampen current cash out signals.

Impact of the modification proposal

Will it address dampened signals?

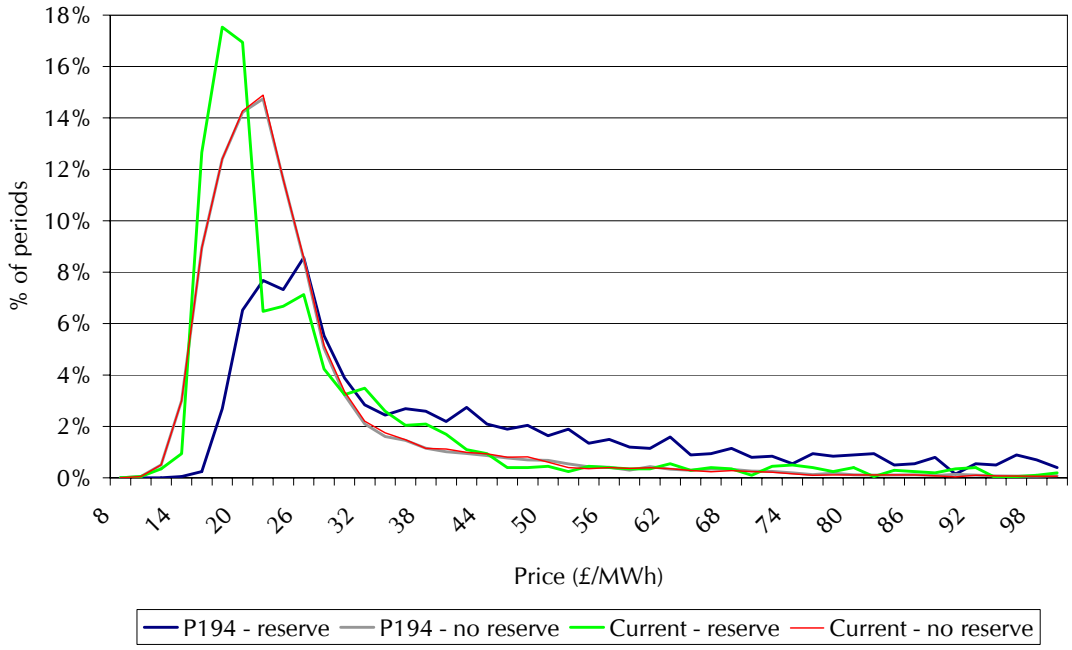
4.39. Having seen that the cash out signals are, at times, being dampened under the current cash out methodology, we analyse below the effect that the introduction of modification proposal P194 could be expected to have in relation to each of the potentially dampening factors described above, and whether it may work to sharpen cash out prices appropriately.

NGET's reserve contracts

4.40. As set out above, the analysis demonstrates that under the current mechanism, cash out prices tend to be slightly lower in periods where NGET calls on reserve than in other periods. We have considered whether this effect would be improved or worsened if modification proposal P194 was introduced.

4.41. Figure 12 reproduces Figure 7 (which considered the distribution of cash out prices in periods when reserve was used and when it was not), and additionally shows the cash out prices that would have applied over the same period if the P194 derivation methodology had been used (and assuming that participants' behaviour had not changed).

Figure 12: Distribution of SBP in periods with and without use of reserve



4.42. Figure 12 demonstrates that in periods where no reserve was called by NGET, the SBP would have been almost identical under the P194 methodology as under the current calculation. However, in periods where reserve was used, the SBP would generally have been higher using a PAR100 calculation.

4.43. This analysis suggests that modification proposal P194 would reduce the dampening effect that NGET's use of reserve has on cash out prices. This impact is likely to be associated with the fact that lower exercise prices for reserve are not likely to be among the highest priced offers that fall within the PAR100 volume.

4.44. In addition to this effect, there could be a further impact on NGET's use of reserve under P194 if it results in increased participation in the BM or greater balancing by parties. Both such effects would reduce the extent to which NGET had to rely upon reserve contracts and hence reduce the potential for reserve costs to dampen cash out prices.

Repricing of bids and offers

4.45. As noted earlier, the current average cash out prices may reduce the extent of repricing, because market participants cannot use the main cash out price to inform them of the marginal price and hence assist them in repricing decisions. Introducing a cash out price which more closely reflects the marginal price should make it easier for participants to reprice in response to changing system conditions.

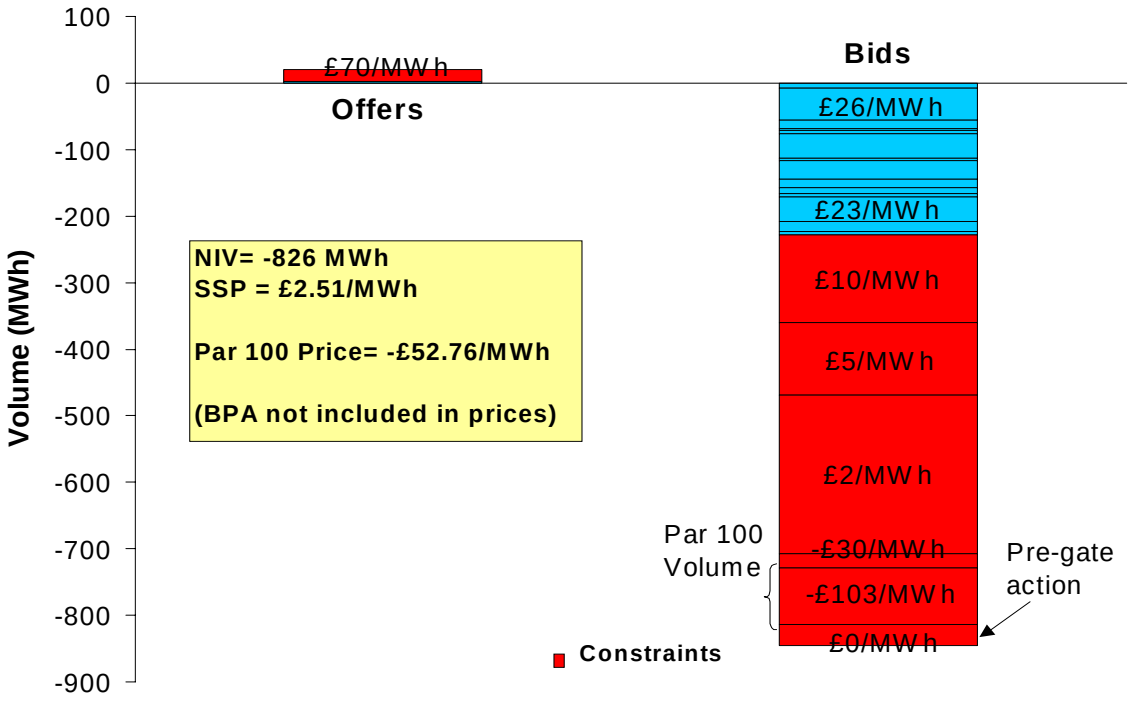
4.46. More active participation in the BM and/or contracting ahead could have associated benefits in relation to liquidity. This is discussed in more detail in paragraph 4.90 onwards.

Tagging

4.47. The analysis set out above demonstrated that the failure of the tagging process in some periods to remove system trades from the stack of bids and/or offers used to determine the imbalance charges can affect the cost reflectivity of cash out charges and the associated signals for market participants. Ofgem has considered whether the effect of this tagging issue on cash out prices is likely to be exacerbated or diminished if modification proposal P194 was introduced.

4.48. To consider this, Figure 13 below updates the analysis in Figure 9, which considered whether or not system actions might fall within the NIV and whether this would be exacerbated by P194. The tagging methodology would not change under modification proposal P194, and so the NIV would still be calculated by netting the offer stack against the bid stack. However, SSP would be calculated using the weighted average of the most expensive 100MWh.

Figure 13: Bid/Offer stack for 26 September 2005, settlement period 19



Source: NGET

4.49. The SSP under modification proposal P194 would have been -£52.76/MWh in this period, compared with an SSP under the current methodology of £2.51/MWh and the weighted average of the top 100MWh of *energy* actions in the NIV stack of around £23/MWh.

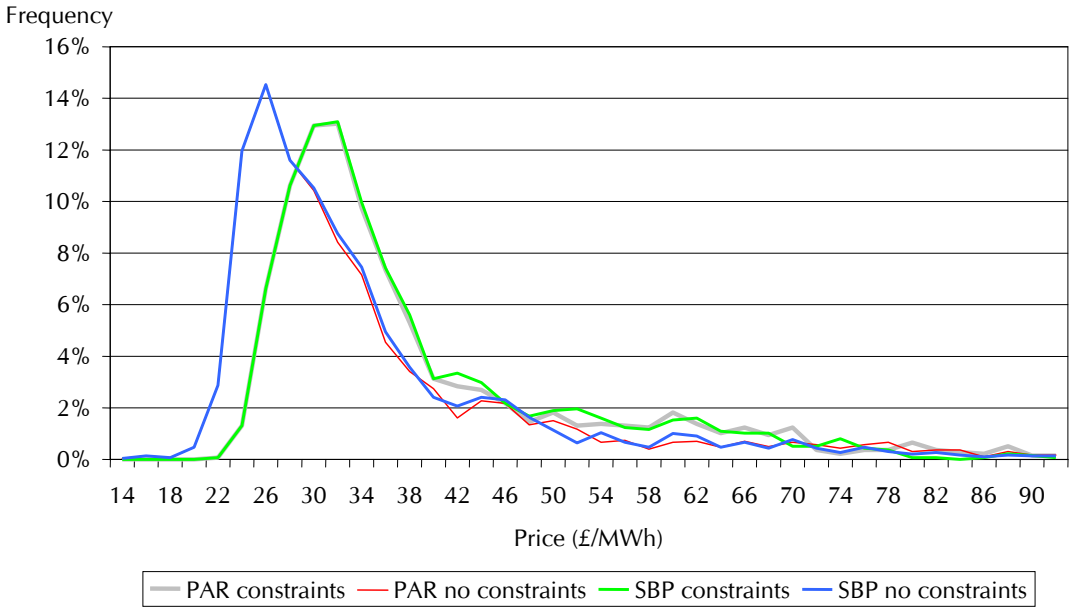
4.50. As discussed above, it is not possible to identify from this analysis whether there were energy actions available that could have replaced the system actions, and hence what the price would have been in the absence of these system actions. However, it is clear that in this period, the presence of system actions would have had a much more significant effect on SSP under P194 than under weighted average pricing. It is also clear that under the current methodology the cash out signal given was weak for this period.

4.51. As stated previously, NGET undertook further analysis on tagging, looking at the period 1 April 2005 – 14 November 2005. Of the 10,946 periods considered, system constraints were present in 28% of them (i.e. 3,104

periods). However, not all of these constraints would have been resolved in the cash out mechanism, nor is it necessarily the case that these trades were not tagged out by the current tagging methodology.

4.52. Figure 14 updates analysis in Figure 10 (which considers the difference in the distribution of prices in constrained and non-constrained periods where SBP was the main price). The updated analysis considers what modification proposal P194 prices would have been in these periods.

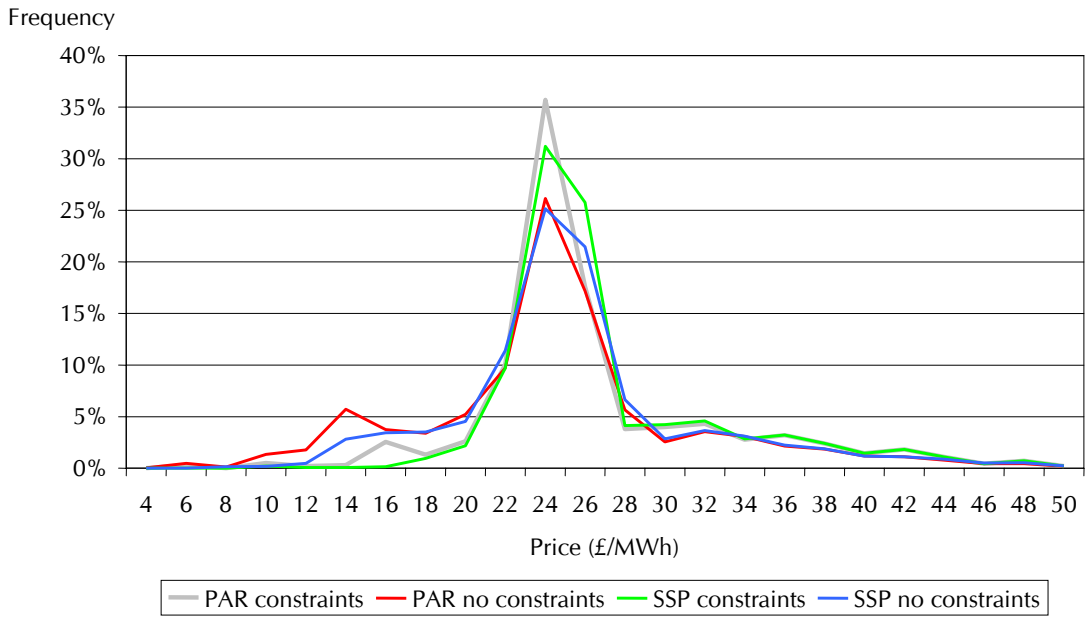
Figure 14: Impact on buy prices of P194 in constrained and unconstrained periods



4.53. Figure 14 provides no evidence that, on average, constrained periods have a stronger effect on the cash out price under the PAR100 methodology than under the weighted average methodology. Based on this historical data, the difference between prices in constraint periods and constraint-free periods during the period analysed is £3.72/MWh under the current mechanism, and £3.74 under the PAR 100 mechanism.

4.54. Figure 15 provides analysis of the impact on SSP of modification proposal P194 in constrained and unconstrained periods.

Figure 15: Impact on sell prices of P194 in constrained and unconstrained periods



4.55. This suggests that the difference in SSPs due to constraints is more significant under PAR 100 than under the current methodology – on average, constrained periods increase the price by £1.96/MWh under the proposed mechanism, versus £1.41/MWh under the current scheme.

4.56. In conclusion, the above information tends to suggest that cash out prices are different in periods with constraints from prices in constraint –free periods, suggesting that tagging is having an impact. However, the PAR 100 methodology does not generally appear to increase this effect for SBP although it appears to have some impact for SSP. As shown in Figure 13, there are, however, examples where modification proposal P194 would have a significant impact in this respect.

4.57. If distortions caused by the inclusion of system actions are one explanation of why average prices are not tending to marginal prices, it does not appear that P194 would resolve this issue. Conversely, where the constraint action is within the 100 MWh volume used to derive the main cash out price, the modification proposal might, in fact, exaggerate the impact of the inclusion of this trade.

Average versus Marginal

4.58. Table 3 shows the impact that modification proposal P194 would have had on the SBPs and SSPs for a period of over a year (from 1 April 2004 to 30 June 2005) by comparing the PAR100 cash out prices with the average cash out prices in each period.

Table 3: Impact of P194 on cash out prices without participant response

Change in cash out prices (£/MWh)	Proportion of main cash out prices with differential within that range	
	SBP	SSP
<=41	99.0%	
<=25	98.4%	
<=20	98.0%	
<=15	97.3%	
<=10	96.2%	
<=5	93.3%	
0	83.9%	75.7%
>=-1		88.6%
>=-2		93.9%
>=-5		98.6%
>=-10		99.7%

4.59. The table shows that modification proposal P194 would not have had a substantial impact in most Settlement Periods. Thus, in 84% of periods when SBP was the main price and 76% of periods when SSP was the main price, there would have been no change in the cash out prices if modification proposal P194 had been implemented. However, in just under 4% of the periods when SBP was the main cash out price, the proposal would have resulted in cash out prices that were more than £10/MWh higher than under

the current arrangements. The distribution of outcomes is narrower for SSP – in only 1.4% of the periods when SSP was the main cash out price would the SSP have been more than £5/MWh lower than under the current arrangements.

4.60. For the purposes of its SO incentive scheme,[36] Ofgem asked NGET to consider, based on historic data, the overall impact on its SO costs resulting from modification proposal P194. As part of this analysis, NGET considered the impact that P194 would be likely to have on SSP and SBP. Its conclusions were that the modification proposal would have a small effect on SSP for a large proportion of the time and large effect on SBP on only a small number of occasions.[37] This confirms the results shown in Table 3.

4.61. Table 3 does not analyse in which periods cash out prices would have been different under modification proposal P194. However, as Figure 4 indicated, the main defect with the current arrangements that modification proposal P194 seeks to remedy relates to the failure of the average derivation of cash out prices to tend to the marginal price at times of system stress. If the modification proposal affects imbalance prices as expected, there should be a substantial difference in the imbalance prices at times of system stress. Consequently, it is not surprising that modification proposal P194 may not have a substantial impact on an average measure of cash out prices since most periods are not periods of system stress.

4.62. To explore whether the modification proposal does improve the signals to market participants during times of system stress, we have considered whether the degree of change in cash out prices in moving from average to marginal

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[36] Each year, Ofgem sets an incentive scheme covering the costs of keeping the system in balance. The scheme sets a target level of costs and allows NGET to keep a proportion of any savings it can make against this target. If actual costs exceed the target, NGET pays a share of additional costs. Part of the process of setting those SO costs is to determine an appropriate level of costs given different factors that could potentially impact on NGET's balancing activity.

[37] NGET estimates that P194 would have reduced imbalance prices by 4% in the case of SSP and increased SBP by 6% across all periods. The average change in value at times of system stress would be 15% for SBP and would reduce SSP by 6% when this was the main price. As only 22% of the time, SBP is the main price, it considers that the overall impacts on average are balanced, although at times of system stress there may be an impact on prices.
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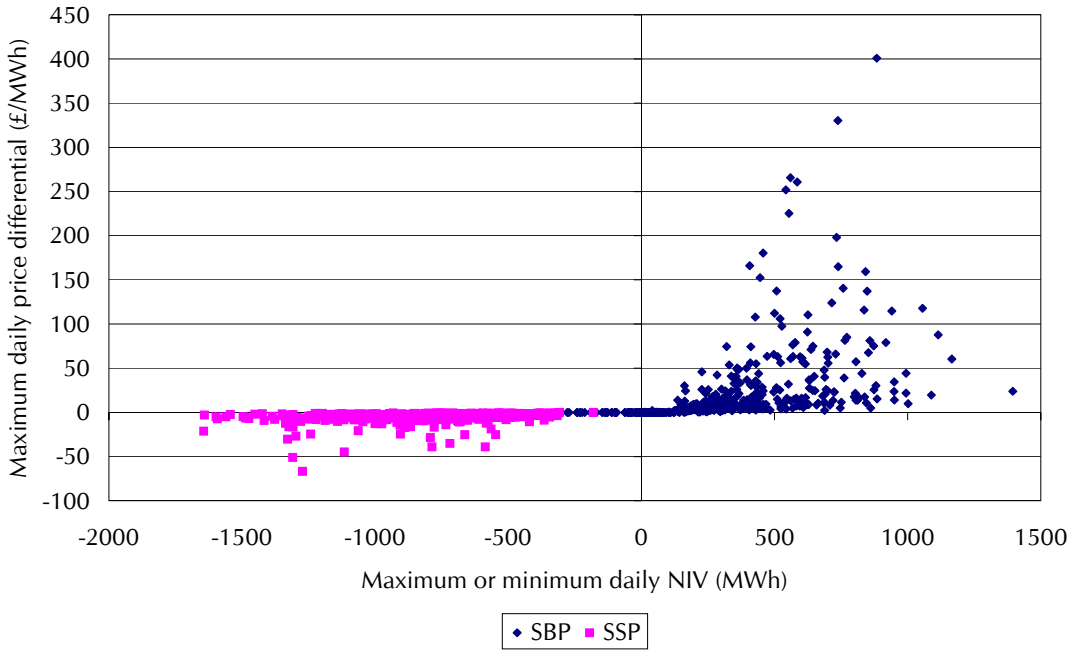
prices is related to system length by further examining the data underlying Table 3.

Correlation between system length and change in cash out price in moving from average to modification proposal P194 methodology

4.63. Figure 16 shows the largest difference between the PAR 100 price and current weighted average price for each day against the extreme NIV for that day,[38] for the period 1 April 2004 to 30 June 2005. Each data point represents a single day and the price differences are shown as the absolute difference between the average price and the price determined under the PAR 100 methodology.

Figure 16: Correlation of maximum daily price differentials with NIV



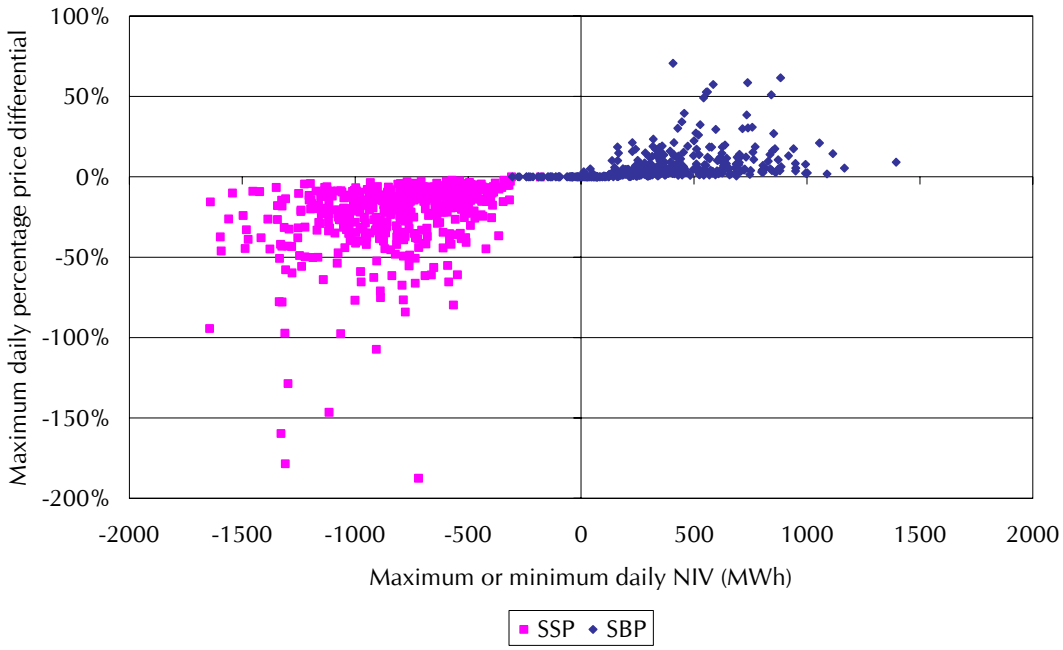
4.64. The analysis suggests that in absolute terms the impact of P194 is greater on buy prices than on sell prices. As shown in Figure 16, a shorter system (more positive NIV) generally corresponds with increases in SBP. On days when the system is already close to balance (i.e. NIV near to 0), there is very little effect

[38] When the data point represents a change in SBP it is plotted against the maximum daily NIV. When it represents a change in SSP it is plotted against the minimum daily NIV.

on cash out prices. However, there is some spread in these data and on some occasions the data suggests that there would not have been a large difference in SBP even when the system was particularly tight. Hence, there does not appear to be a very strong correlation.

4.65. This difference in impact between buy and sell prices is primarily attributable to differences in the average size of the SBP and SSP. If the SBP was already high, then a relatively large absolute difference will only represent a fairly small percentage change. Equally, if the average SSP was low, then small differences to the cash out price as a result of P194 may have a larger proportional impact. This can be seen by comparing Figure 16 with Figure 17, which shows the differences in cash out prices on a percentage basis.

Figure 17: Correlation of maximum daily percentage price differentials with NIV



4.66. Figure 16 shows that in percentage terms, the impact on SSP is generally greater than the effect on SBP. Again, there is little impact on prices when NIV is close to zero, and prices can be significantly more extreme under a P194 methodology when the system is significantly long or short. However, both sets of analysis show only weak evidence of a correlation between the cash out price differentials and the length of the system overall. One reason for this

may be partly due to the averaging effect (i.e. taking NIV across the day) or concentrating on daily values.

4.67. Figure 18 and Figure 19 below repeat the analysis above to show the correlation between NIV and the average versus P194 price differentials during peak and off-peak periods respectively. The figures concentrate on the correlation between NIV and prices during peak periods for buy prices (since this is when the system is likely to be short) and during off-peak periods for sell prices (when the system is more likely to be long).

Figure 18: Daily maximum buy price differentials during peak periods

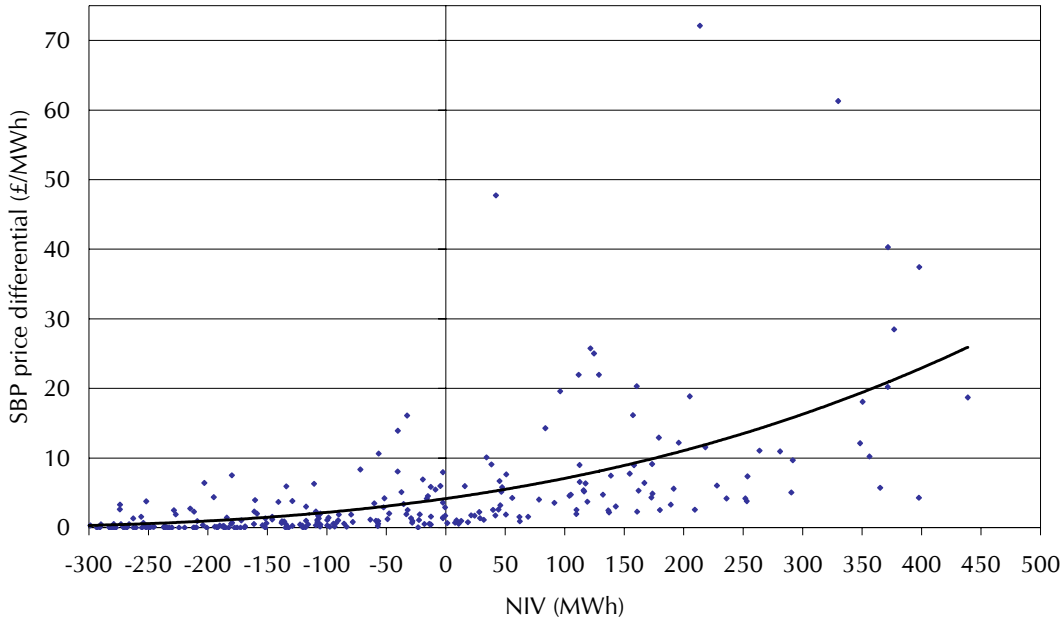
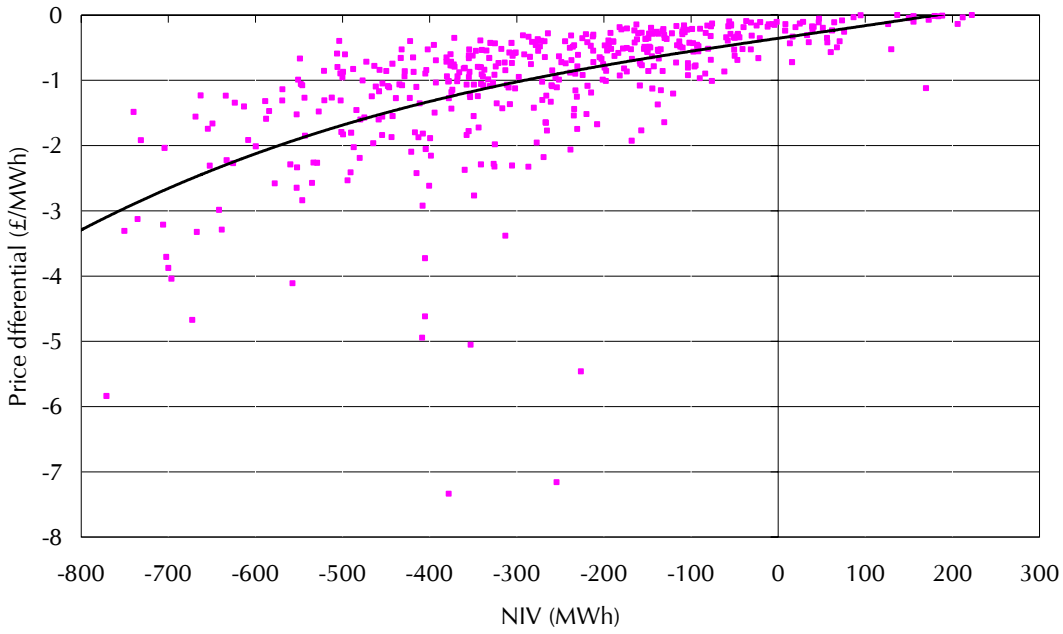


Figure 19: Daily maximum sell price differentials during off-peak periods



4.68. These figures suggest that there is a greater degree of correlation between the system length and the impact of P194 than the analysis of across all daily values suggested. As shown in Figure 18, as the system becomes shorter (NIV becomes more positive), the P194 buy price relative to the average SBP increases. As the system becomes longer (NIV becomes more negative), the P194 sell price relative to the average SSP decreases. The costs to participants of being out of balance would therefore be greater, the larger the overall system imbalance. In other words, modification proposal P194 does appear to provide at least somewhat sharper pricing signals at times of system stress than the current volume-weighted average prices.

Impact on SO costs

4.69. As stated in Chapter 3, in assessing whether the proposal results in stronger signals in relation to energy imbalances, it is necessary to assess what impact the change to a more marginal derivation of cash out prices has on SO costs, particularly at times of system stress.

4.70. Ofgem requested NGET, as part of its analysis regarding its SO costs for 2006/07, to consider the potential impacts of modification proposal P194. NGET's analysis:

- considers the impact on prices, which was discussed in paragraph 4.60 above;
- considers the likely impact on market length; and
- estimates the impact changes to market length would have on its external balancing costs.

Impact on market length

4.71. As stated above, NGET's conclusion on the impact on prices is that the modification proposal would have a small effect on SSP for a large proportion of the time and large effect on SBP on only a small number of occasions.[39] Overall, NGET's assumption is that increasing the incentive to balance should move the market less long when the market is long and less short when the market is short.[40] The net impact for most periods is that the market should be less long, simply because there are more periods when the system is long.

Impact on external balancing costs

4.72. NGET states that if the market becomes generally shorter (and/or free headroom reduces[41]) then, other things being equal, NGET will in general be likely to need to procure more reserve. If the market moves longer and/or free headroom increases then it will need less reserve.

4.73. NGET estimates that an average reduction in NIV of 50 MW (equivalent to around 10% of monthly average NIV) may have an impact on reserve

[39] See footnote 37 for an explanation.
[40] NGET does not consider that the market is likely to go longer in all periods in response to the higher prices associated with SBP (in particular to further minimise their risk of going short and incurring higher SBP). NGET suggests that SBP would have to be significantly higher than offer and forward prices for this behaviour to be observed and this is not borne out by the data it has considered.
[41] This is the measure of the difference between declared generation availability (maximum export limits) and what that plant has declared it will deliver (FPNs).

procurement costs of perhaps £1-2 million per annum. NGET has only presented these figures rather tentatively and considers that there are a number of other complex factors that may act to increase its costs.[42]

4.74. Ofgem considers that, given NGET's external SO incentive target for 2005/06 is currently set at £377.5 million, there might be a greater impact than estimated by NGET. NGET's analysis suggests that modification proposal P194 would have an impact on balancing incentives and behaviour, but does not appear to capture fully the potential benefits of a reduction in SO activity to resolve system shortages. Ofgem considers that it is necessary for NGET undertake further analysis to consider this issue in more detail.

4.75. Nevertheless, overall Ofgem considers that the impact on SO costs is likely to be to reduce them, and by greater than the £1-2 million presented by NGET. Clearly if modification proposal P194 affects market participants' behaviour, P194 should also reduce the number of balancing actions that NGET would have to undertake to resolve system shortages. This issue is considered in the following section.

Impact on market participants' behaviour

4.76. Apart from NGET's analysis of SO costs, the analysis presented thus far has been based on the assumption that the implementation of modification proposal P194 would have no impact on participants' behaviour. However, if participants expect SBP to be higher when the system is particularly short (and SSP to be lower when the system is particularly long), they may choose to protect themselves against exposure to these more unfavourable cash out prices. This could suggest that participants may have a slight bias towards

[42] For example, if the average level of the NIV is reduced (less long), NGET notes that there are likely to be offsetting impacts on its incentivised balancing costs, which ultimately is recovered from consumers under NGET's SO incentive scheme. This is because its incentive mechanism contains Net Imbalance Adjustment (NIA) component. The NIA component of NGET's SO incentive scheme is designed to adjust NGET's costs to reflect the fact that it has little control over the extent to which participants choose not to balance their positions. The extent to which the volume of imbalances falls (assuming no changes to prices) could increase NGET's balancing costs.

adopting somewhat longer positions than they currently do in order to guard against being exposed to high SBPs. Analysis by Elexon (in Appendix 2) would tend to support this overall assumption about participant behaviour (i.e. that it should increase incentives to balance, but with stronger incentives to avoid being exposed to SBPs than to SSPs).[43]

Estimating cash out prices if behaviour changed

4.77. To assess what effect such a change in participant behaviour might have on cash out prices, we asked NGET to reanalyse what cash out prices would have been under modification proposal P194, but adjusting downwards the NIV of the system (for simplicity this was achieved by making it longer) and the volume of offers submitted to the BM (i.e. reducing the amount by which NGET can increase output).

4.78. The results of this analysis are presented in Table 4, where the data is presented in order of increasing system length (i.e. of the periods studied, the system was shortest in period 38 on 13 November 2005 and least short in period 14 on 11 May 2005). The table shows:

- the change in SBP due to implementing modification proposal P194 but assuming no change in participant behaviour (hence no change in system length or number or size of offers); and
- the effect of a 5% and 10% reduction in the volume of each *offer* made available to NGET together with the corresponding reduction in the extent to which the system is short; assuming:
    - First, that there is no change in the volume of corresponding *bids* accepted by NGET (i.e. the increase in plants' output has not

[43] In the analysis Ofgem requested Elexon undertake, it found that P194 is likely to provide an increased incentive to avoid being generally short that is proportional to the extent a Party is net short. P194 is likely to provide an increased financial incentive to avoid being generally long that is proportional to the extent a Party is net long. Therefore, P194 is likely to increase the financial incentive to avoid either being consistently long or consistently short (i.e. having either a net positive or net negative imbalance volume over an extended period). The incentive to avoid being consistently short is likely to be increased to a greater extent than that for being generally long.
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caused them to change the extent to which they are willing to reduce their output), and

- Second, that the volume of *bids* made available and accepted by NGET, decreases by 50% of the change in the volume of *offers* i.e. if NGET accepts 10 MWh less *offers*, it also accepts 5 MWh less *bids*, with the reduction spread uniformly over the bids it had previously accepted.

4.79. The two tables 4 (i) and (ii) compare prices under the various cases with those that were actually seen i.e. the volume-weighted average prices. Table 4(ii) compares the SBPs when modification proposal P194 is assumed to cause participants' behaviour to change with those that would occur under P194 without any change in participants' behaviour.

Table 4: Impact of changes in participant behaviour on SBPs under current mechanism and under proposed modification P194 when the system is short (£/MWh)

i. Impact relative to current cash out mechanism[44]	Settlement Period	NIV	No change in behaviour	Impact when participants go longer but no change in bid volume		Impact when participants go longer, and bid volumes change by 50% of change in offer volumes	
				5% reduction in offer volumes	10% reduction in offer volumes	5% reduction in offer volumes	10% reduction in offer volumes
13-Nov-05	38	866	18.84	18.84	18.84	18.84	18.84
18-Jun-05	24	666	6.26	6.26	5.97	6.26	6.26
10-Nov-05	34	459	49.11	39.66	30.21	48.08	47.04
24-Oct-05	38	339	1.47	0.49	0.49	1.59	1.71
17-Jul-05	42	185	4.27	-4.96	-5.05	0.58	-3.10
08-Jun-05	23	143	7.11	4.72	1.90	6.90	6.69
05-Sep-05	36	125	0.00	0.00	0.00	0.00	0.00
08-Apr-05	45	78	0.00	-0.29	-1.36	-0.09	-0.24
30-May-05	14	74	0.00	-0.06	N.A.*	-0.03	-0.06
10-Nov-05	18	72	0.00	-4.43	-12.66	-1.44	-3.42
09-Apr-05	19	67	0.00	-6.16	-7.26	-2.47	-5.80
13-Apr-05	32	46	0.00	-0.23	-4.66	-0.07	-0.20
21-Apr-05	5	44	0.00	0.00	0.00	0.00	0.00
11-May-05	14	2.0	0.00	N.A.*	N.A.*	N.A.*	N.A.*

ii. Impact relative to P194 mechanism (£/MWh)	Settlement Period	NIV	Impact when participants go longer but no change in bid volume		Impact when participants go longer, and bid volumes change by 50% of change in offer volumes	
			5% reduction in offer volumes	10% reduction in offer volumes	5% reduction in offer volumes	10% reduction in offer volumes
13-Nov-05	38	866	0.00	0.00	0.00	0.00
18-Jun-05	24	666	0.00	-0.29	0.00	0.00
10-Nov-05	34	459	-9.45	-18.90	-1.04	-2.07

[44] *These values are not applicable because the change in offer volumes brings about a change in the sign of NIV (i.e. from positive to negative or negative to positive). The system in this case would flip from being short to long.

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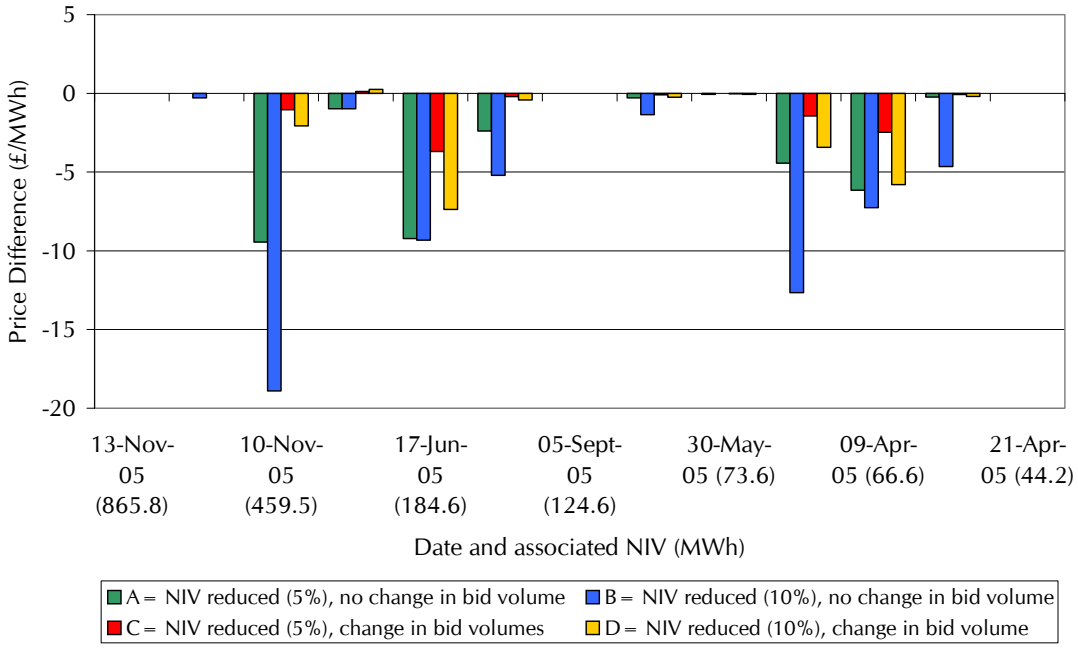
24-Oct-05	38	339	-0.98	-0.98	0.12	0.24
17-Jul-05	42	185	-9.23	-9.32	-3.69	-7.37
08-Jun-05	23	143	-2.39	-5.20	-0.21	-0.42
05-Sep-05	36	125	0.00	0.00	0.00	0.00
08-Apr-05	45	78	-0.29	-1.36	-0.09	-0.24
30-May-05	14	74	-0.06	N.A.*	-0.03	-0.06
10-Nov-05	18	72	-4.43	-12.66	-1.44	-3.42
09-Apr-05	19	67	-6.16	-7.26	-2.47	-5.80
13-Apr-05	32	46	-0.23	-4.66	-0.07	-0.20
21-Apr-05	5	44	0.00	0.00	0.00	0.00
11-May-05	14	2.0	N.A.*	N.A.*	N.A.*	N.A.*

4.80. Figure 20 summarises Table 4(ii) above. It shows for the settlement periods and dates selected for the different levels of system tightness (NIV), the impact on SBP.

Figure 20 – Impact relative to proposed modification P194



4.81. Whilst it has only been possible to analyse a small number of periods in the time available, the results appear to corroborate what might have been anticipated, namely that:

- the impact of participants going longer is almost always to reduce the SBP relative to the price that would prevail with no change in behaviour;

- when the system is particularly short (e.g. the top two periods shown in each table when the system was short by more than 650 MWh before participants' behaviour is taken into account) changes in participants' behaviour have little or no effect on the impact of modification proposal P194;

- when the system is almost balanced changes in participant behaviour have relatively little effect (e.g. the bottom two periods in the table when the system was short by less than 50 MWh before participants' behaviour is taken into account);

- the greatest impact of participants' behaviour on SBPs occurs in between these extremes and the result is lower SBPs than would have occurred with no change in behaviour. If participants who choose to go longer also make more bids available then the impact of their behaviour on prices will be limited.

4.82. In other words, this analysis also tends to suggest that there is a correlation between the impact of modification proposal P194 and system length in that the maximum impact on prices occurs during those periods when the system was shortest. It is also the case that the changes in prices during these more recent periods when BETTA was live are comparable to those seen, for similar system lengths, in the period analysed prior to BETTA. In other words, the introduction of BETTA does not seem, on the basis of this limited sample of data, to have had a significant impact on the likely effect of implementing modification proposal P194.

Quantifying the impact of changes in behaviour

4.83. As regards the impact that the change in prices would have on overall imbalance costs, Elexon estimates that total net imbalance charges, would have been £32 million higher, or 30%, during 2004/05 if modification proposal

P194 had been in place. Further details of Elexon's analysis can be found in Appendix 2 and in the discussion on competition and distributional effects included later in this chapter. Since Elexon's analysis assumes no change in participant behaviour, this increase in total net imbalance charges would not have been accompanied by any change in balancing costs.

4.84. If participants' behaviour were to change as a result of modification proposal P194, we estimate that balancing costs could fall by between £13 and £87 million per year. Appendix 4 explains how this range was derived. In summary, the analysis seeks to determine the savings associated with a reduction in the number of balancing actions caused by changes to the NIV as a result of changes in participant behaviour.

Interactions with gas market

4.85. As stated in Chapter 3, the modification proposal could impact on the interactions between gas and electricity markets as sharper signals in the electricity market could affect decisions by gas-fired generators on whether or not to generate.

4.86. Ofgem has identified the period 26 December 2005 – 1 January 2006 as being of particular interest. During this period both the gas and electricity markets were tight and this led to NGET eventually issuing a High Risk of Demand Reduction ('HRDR') notice to the electricity market. In the event, system security was maintained. Nevertheless, it is interesting to consider the response of gas-fired generators over this period and the interactions between the signals in the electricity and gas markets. It should be noted that market conditions during this period were very tight and this analysis is in no way representative of typical circumstances, but is intended to reflect the possible effects in periods of extreme system stress.

Position in the electricity market – 28 - 29 December 2005

4.87. Appendix 4 analyses the interactions between the gas and electricity markets during the period 26 December 2005 – 1 January 2006. During that time,

NGET issued a Notice of Insufficient Margin, based on the unavailability of some generators. In summary, the analysis suggests that the opportunity to offer in much higher prices and be accepted by NGET may not have been clear to CCGTs, as the average cash out price was providing relatively weak signals even though an HRDR notice had been issued. In the first instance, this will have impacted on the economy and efficiency with which the system was operated. Moreover, if the electricity system had been much tighter then there could have been significant security of supply impacts (a quantification of security of supply impacts is discussed in paragraphs 4.114 to 4.118 below.

Summary of economy and efficiency impacts

4.88. In summary, the analysis presented above suggests that P194 would have benefits in terms of increased efficiency and economy. P194 would provide stronger signals for participants to balance their positions at times of system stress, whilst cash out prices would remain largely unaffected at other times. This should improve the efficiency and economy with which the wholesale market operates as market participants have stronger incentives to balance their own positions. To the extent that participants responded to these signals by making more plant available, NGET's balancing costs should also fall, again increasing the efficiency of the system. Ofgem has estimated that the proposal could reduce NGET's balancing costs by between £13 and £87 million per annum. However, the costs of reducing imbalance volumes (for example by increasing plant availability, holding plant back for self-reserve etc.) would partially offset the reduction in NGET's balancing costs.

Table 5: Summary of economy and efficiency impacts[45]

ECONOMY AND EFFICIENCY	(i) Are current cash out prices providing signals?	Tagging issues	✗ ✗	-
		Repricing of bids and offers	✓	-
		Reserve	✓	-
		Average versus marginal	✓ ✓	-
	(ii) Impact of less dampened signals?	SO costs	✓ ✓	>£2 million
		Change in participants' behaviour	✓ ✓ ✓	£13 to £87 million
OVERALL ASSESSMENT	✓ ✓			

Competition and distributional impacts

4.89. In considering the potential effect of modification proposal P194 on competition, Ofgem has focused on three main impacts:

- competition effects associated with impacts on liquidity;
- the potential for parties to game; and
- distributional effects whereby different types of market participants or different sizes of market participants may be more affected than others.

Liquidity

4.90. It might be the case that a more marginal cash out price would increase the volume of trades undertaken in near real time markets as participants would have stronger incentives to avoid exposure to cash out prices relative to the

[45] See Footnote 3, which applies to all summary tables in this document.

current arrangements. Liquidity in these near real time markets is beneficial as it aids price discovery.

4.91. We have sought to explore the effect of cash out signals on liquidity in near real time markets by examining whether the liquidity in these markets changed following the implementation of Modification Proposal P78. This modification introduced reverse cash out prices[46] based on forward prices and had the effect of dampening cash out prices. Prior to its implementation, cash out prices were volatile and generally higher than market prices. To avoid exposure to these cash out prices, participants had typically chosen to go long or at any rate tried hard to balance their positions. After the implementation of P78, the incentives to go long reduced and system length noticeably shortened.

4.92. Consequently, if liquidity in near real time markets fell when P78 was implemented, this might indicate that the volume of trading in near real time markets is partly a function of sharpness of the signals of the cash out regime. In turn, if modification proposal P194 were to be implemented then it might be the case that liquidity of near real time markets increases.

4.93. Figure 21 shows the total volumes of contracts traded on the Spectron platform each month around the period when P78 was implemented on 11 March 2003 and the average monthly system length (NIV) over the same period.

[46] The reverse cash out price is applied to participants who are out of balance in the opposite direction to the system i.e. they are long when the system is short and vice versa.
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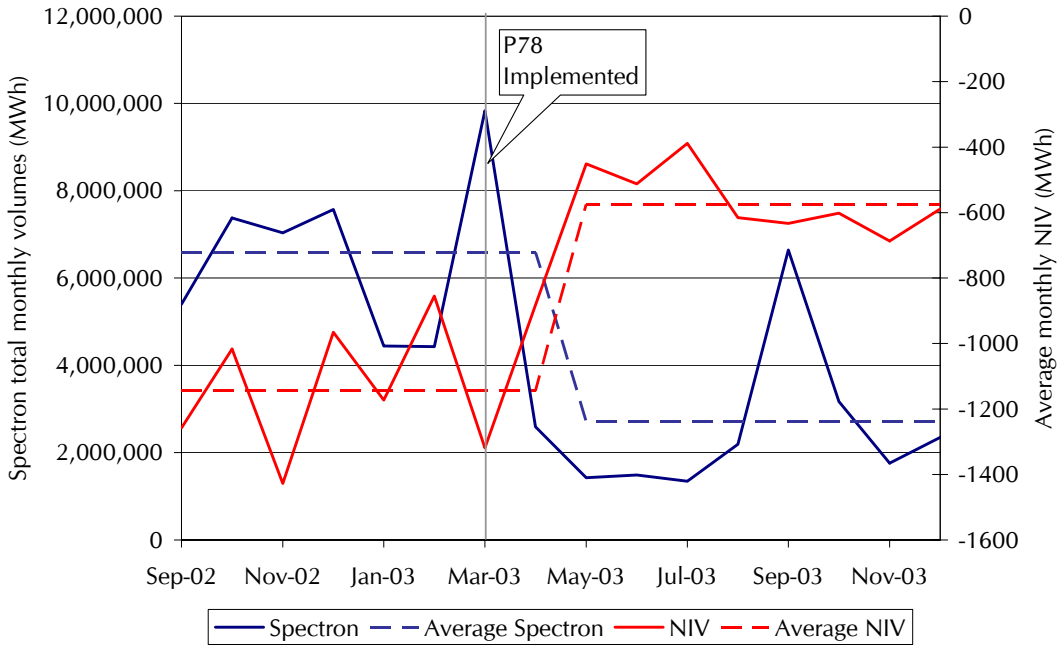
Figure 21: Total monthly volumes traded on Spectron and average monthly NIV values around the time P78 was implemented



4.94. In the period examined before implementation of modification proposal P78 (September 2002 to March 2003) the average volume traded each month was 6.6 TWh. In the period examined after implementation of P78 (March 2003 to December 2003) the average volume this volume fell to 2.7 TWh, i.e. volumes fell by nearly 60% after implementation of P78. At the same time, the average amount by which the system was long more than halved, falling from 1145 MWh to 575 MWh.

4.95. Whilst it is difficult to be certain how much of this effect was due to P78 and how much to other market developments, the evidence of P78 suggests that sharper cash out prices might lead to an increase in near real time liquidity.

Gaming

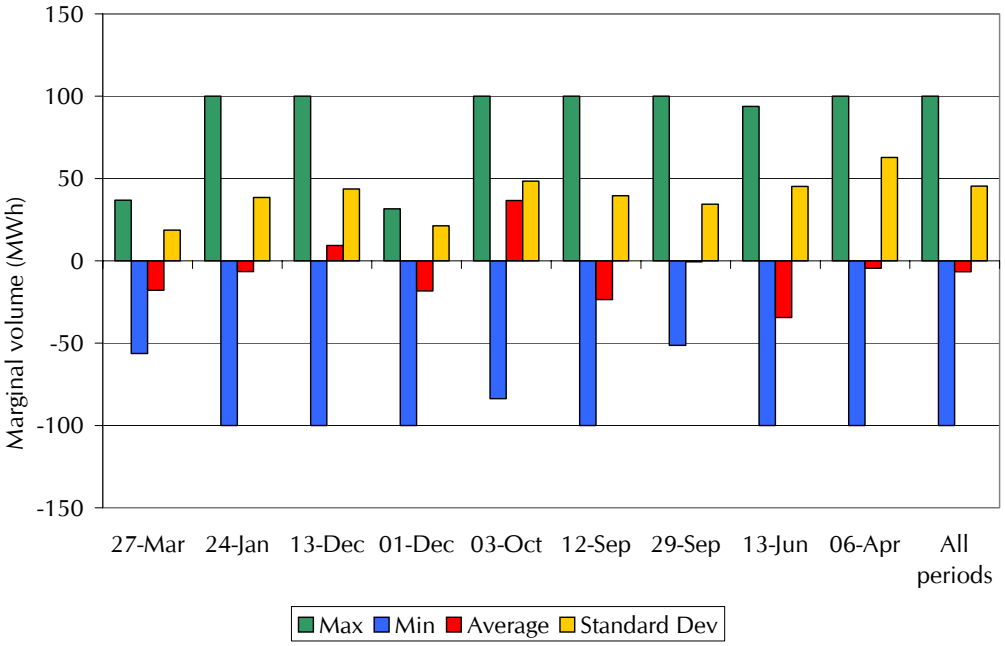
4.96. As identified in chapter 2, there is concern that more marginal forms of pricing could increase the opportunity or incentives for market participants to 'game' the cash out determination system, so that prices are set in a manner more favourable to that participant relative to others. This might be the case as the

ability to influence cash out prices would increase as the volume of trades used to calculate it is reduced. Given that under modification proposal P194 the cash out price would be based on a smaller sample of trades, it follows that any trades that fall within the cash out calculation would be likely to have a larger impact on the cash out price than under the weighted average methodology based on a larger volume of trades.

4.97. Ofgem raised similar concerns in its decision on modification proposal P136, which proposed that the main price be set by the price of the single marginal action in the NIV stack. The 'chunky' marginal methodology of the P194 proposal, whereby cash out prices are not set just by the action with the most extreme price but instead by the volume-weighted average of the 100 MWh of actions with the most extreme prices, could in part be seen to mitigate this potential effect.

4.98. To understand the scope for gaming of cash out prices, Ofgem has assessed the typical volume of trades in the BM to understand the number of trades that would, on average, be used in the calculation of the cash out price under modification proposal P194.

Figure 22: Statistics on the size of the marginal actions taken in each period on selected days



4.99. Figure 22 shows that, for the periods studied, the average size of the marginal action is significantly smaller than 100 MWh. Therefore, under P194, it is likely that the cash out prices are set from actions taken by more than one BMU. However, on all but two of the days assessed, there was at least one balancing period where the marginal action was approximately 100 MWh, implying that the cash out price under modification proposal P194 will on some occasions be determined on the basis of a single action.

4.100. Table 6 provides information on the distribution of the size of marginal actions for the same sample of 432 periods. It confirms that, in most instances, more than one action will be included in the calculation of cash out prices under P194. In only 16% of the periods studied was the size of the marginal action greater than 75 MWh, so the percentage of periods in which one action sets the cash out price will be less than this.

Table 6: Historical analysis of distribution in size of "marginal" trades[47]

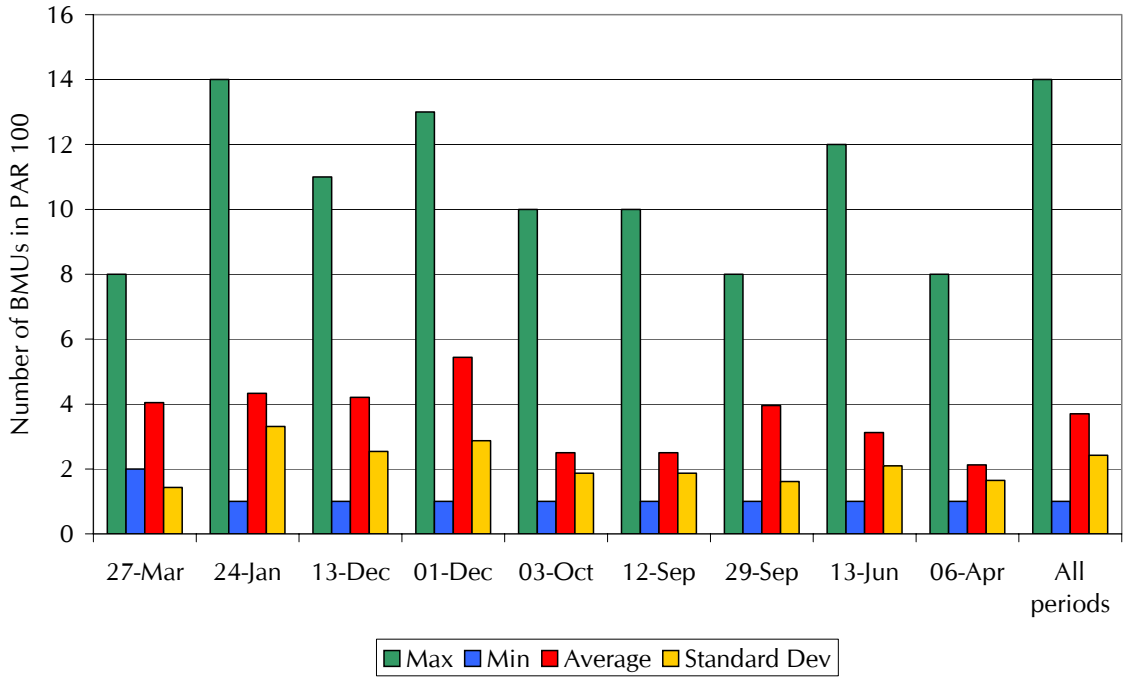
	Marginal volume (MWh) (in absolute terms)				
	<5	**<10**	**<25**	**<50**	**<75**
Total (out of 432 periods)	61	316	196	105	68
% of all periods	14%	27%	55%	76%	84%

4.101. Thus, it appears likely that the 'chunky' nature of P194 will provide some mitigation against concerns that one participant might be able to unduly influence the level of the cash out price. However, there may still be occasions when it is possible for a participant to influence cash out prices because the price is determined by only one or two actions. This seems to be

[47] Based on analysis over 'representative periods'. Marginal trade relates to the highest priced bid/lowest offer

corroborated by the analysis shown in Figure 23, which suggests that typically actions from 3-4 BMUs will cover the top 100 MWh of the stack and at times there have been up to 14 different BMUs within the stack.

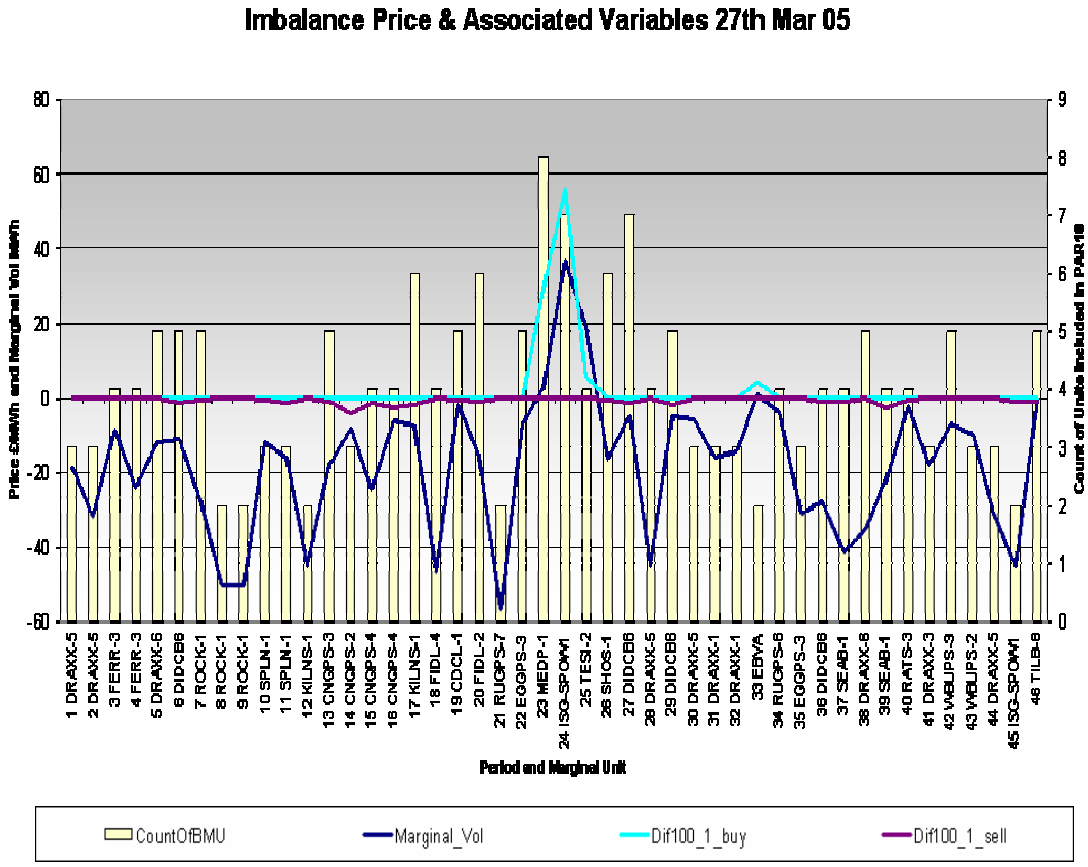
Figure 23: Number of BMUs in the top 100 MWh of actions



4.102. The analysis shown in Figure 23, which suggests that typically actions from 3-4 BMUs will cover the top 100 MWh of the stack and at times there have been up to 14 different BMUs within the stack. However, the analysis does show that on certain occasions there has only been one BMU in the PAR100.

4.103. Figure 24 provides a more detailed view over 48 settlement periods on 27 March 2005 in relation to the size of marginal volume and the number of BMUs in the PAR 100.

Figure 24: Detailed analysis of cash out variables for each period of 27 March 2005



Source: NGET

4.104. On the bottom axis in Figure 24 is the actual BMU that was the marginal unit for that settlement period. This analysis was provided by CORWG and shows that it was not the same BMU in each period that is the marginal plant (i.e. that there was a degree of competition between BMUs). The analysis available from CORWG looked at a number of other periods and confirmed that there was some diversity in the stack.[48]

4.105. Ofgem notes that respondents to the consultation have identified a number of factors that may act against any concerns that P194 would provide opportunity or greater incentives to act anti-competitively:

[48] This analysis did not consider the ownership of BMUs within the stack.

- competitive pressures would ensure that competing, lower priced energy balancing trades were selected. NGET has incentives so that it seeks to procure balancing services in the most efficient and economic manner;

- the current cash out rules mean that the highest priced trades are often tagged out. Hence, market participants seeking to raise cash out prices would need to have sufficient information regarding likely bids and offers of other market participants. Given uncertainties and information requirements it may therefore be difficult to ensure that bid or offer sets the marginal price; and

- if such behaviour were detected, market participants could potentially be found in breach of Competition Law.

4.106. Overall, Ofgem considers that, by using a reduced volume of balancing bids and offers to calculate the cash out price, relative to the current arrangements, it follows that the cash out price is more susceptible to undue manipulation by a market participant than would be the case if the current arrangements were maintained. It is also true that this effect is, on average, less than that which would have be the case had modification proposal P136 been implemented because the PAR100 methodology means that most of the time a larger proportion of trades would set the cash out price.

4.107. Therefore, Ofgem accepts that there is a slightly higher risk of manipulation by participants than under the current set of arrangements. However, Ofgem also considers that there are many mitigating factors that mean this impact is likely, in practice, to be negligible. These include the fact that, on average, the 100 MWh volume is typically large enough to include a number of BMU bids and that the inherent uncertainty of the tagging process means that a market participant is unlikely to be able to forecast the operation of the BM with sufficient certainty to be able to manipulate the outcome of the cash out determination.

Distributional impacts

4.108. Concerns were raised in responses to the FMR that modification proposal P194 would have more significant impacts on some parties than others, in particular that smaller and independent parties may be disproportionately affected because they are less able to self balance. For the period 1 April 2004 to 31 March 2005, Ofgem asked Elexon to undertake analysis to assess the distributional impacts that modification proposal P194 would have had on participants' cash out exposure. This analysis assumes that P194 has no impact on participants' behaviour, consequently it may overstate the impact that P194 would have since, as we have shown above, if participants chose to go longer as a result of P194, the impact on cash out prices would be reduced.

4.109. Elexon's findings, which are reported in full in Appendix 2, can be summarised as follows:

- on average, participants could face a net annual increase in net imbalance charges of around 20% (allowing both for Imbalance Charges and RCRC). The largest annual benefit for any Party was £1.93 million and the largest annual dis-benefit was £1.95 million;

- parties that produce less than 1% of energy in the market will be more affected by P194 than larger parties, because smaller parties have a larger proportion of their energy exposed to imbalance charges. However, the effect is almost as likely to benefit smaller parties as penalise them. In other words, while P194 affects smaller parties more than larger ones, this effect may be positive or negative;

- it also follows from the correlation between Credited Energy exposed to Imbalance Charges and the effect on P194 that net generators are likely to benefit and net suppliers be adversely affected. This is simply because net suppliers tend to have more of their Credited Energy exposed to Imbalance Charges;

- P194 provides incentives to avoid being both excessively long or excessively short. However, the incentives on avoiding being consistently short are greater than those for avoiding being generally long (which confirms our assumptions in the 'Economy and Efficiency' section on the likely impact of P194 on participants' behaviour);

- many respondents to the consultation on Modification Proposal P194 suggested that credit cover might have to increase as a result of more extreme cash out prices and pointed out that this would again discriminate against smaller players. Elexon considers that Parties' credit cover requirements may go down as well as up but that smaller Parties are more likely to be adversely affected than to benefit.

4.110. The Elexon analysis suggests that smaller parties on average would be likely to face higher charges overall as a result of a more marginal derivation of cash out prices. This could have the effect of reducing the competitive pressure on larger parties. However, it is also likely to improve incentives on smaller parties to balance their positions, and reward those that are better able to do so.

4.111. To the extent that the analysis suggests that costs would be targeted more towards those market participants out of balance, there is a potential positive impact on competition. As stated in Chapter 3, competition should encourage the most efficient generators and suppliers to be able to gain a competitive advantage over their rivals. To the extent that certain market participants are better able to balance than competitors, then they should not face the costs imposed upon the SO to resolve those imbalances. Therefore, to the extent that the cash out arrangements can be seen to better distribute the costs incurred by the SO in resolving imbalances, this should improve competition.

Summary

4.112. Overall, the effect of P194 on competition seems likely to be slightly positive. Ofgem agrees with many respondents to the Assessment Consultation and DMR, that whilst a move to more marginal cash out prices would, in theory,

increase the potential for cash out prices to be manipulated, in practice this is unlikely to be a major problem. Conversely, if P194 has any impact on liquidity, it should be to increase it.

4.113. As regards distributional effects, there is some evidence that smaller Parties and net suppliers are, at the margins, more likely to be adversely affected by P194 whereas larger Parties and net generators would be more likely to benefit from it. The analysis suggests that in respect of smaller players there are some that could benefit from the proposal. In addition, Elexon's analysis suggests it is also likely to improve incentives on smaller parties to balance their positions, and reward those that are better able to do so.

Table 7: Summary of competition and distributional impacts[49]

COMPETITION AND DISTRIBUTIONAL IMPACTS	Liquidity	✓
	Gaming	✗
	Distributional impacts	✓
OVERALL ASSESSMENT	✓	

Security of supply

4.114. In this section we consider qualitative and quantitative analysis on the effects that P194 could have on short and long term security of supply.

Short term effects

4.115. If participants chose to adopt longer positions as a result of P194 being implemented, this is likely to enhance short-term security of supply, because more plant will be generating than would otherwise be the case. In other words, there are likely to be fewer occasions on which the system would be short. Of course, once all the power plants capable of generating electricity at

[49] See Footnote 3, which applies to all summary tables in this document.

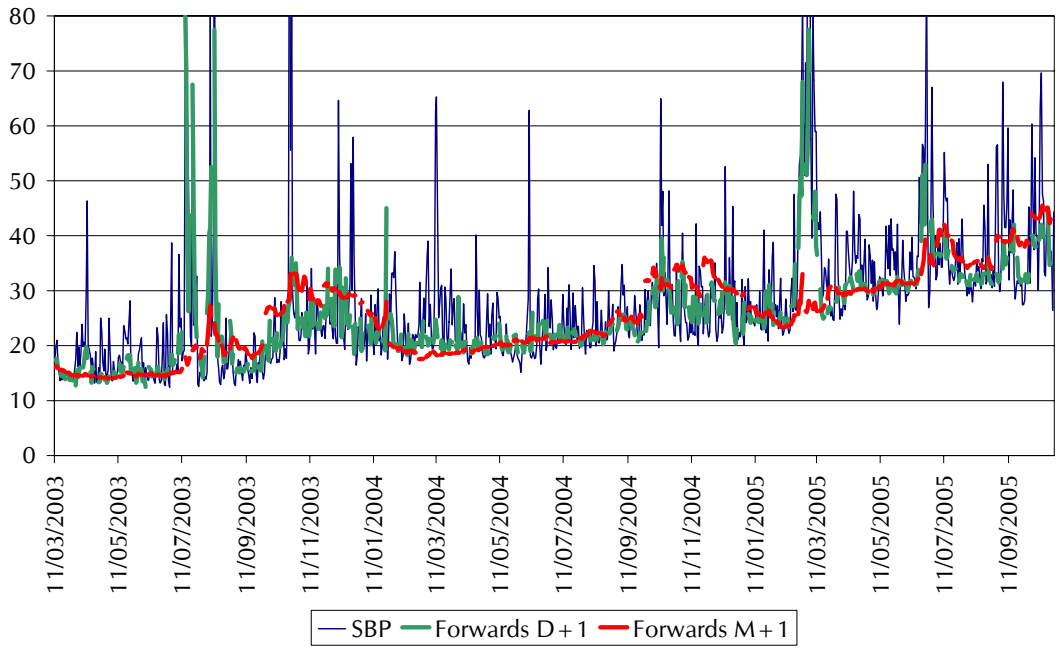
a particular moment are already producing at full capacity, P194 can have no further effect.

4.116. Some respondents to the consultation on P194 argued that participants might choose not to contract the output of unreliable generating plants because of the risk that their breakdown could result in the participant being exposed to disadvantageous cash out prices. Whilst this possibility cannot be entirely excluded, Ofgem takes the view that if the expectation of higher SBPs feed through into spot and forward prices this will provide an incentive for participants to improve the reliability of their plants so that they can benefit by contracting for additional power at these more favourable prices. It was notable, for example, that the introduction of the New Electricity Trading Arrangements, which first targeted balancing costs on to out-of-balance participants instead of socialising the costs, led to an appreciable improvement in the reliability of plant.

Long term effects

4.117. In the long term, sharper price signals may be expected to have a positive effect on security of supply in that they will provide stronger incentives to bring new plant to market. Figure 25 plots weekly average values of SBP, month-ahead forward prices and day-ahead forward prices, for the period March 2003 to November 2005.

Figure 25– Weekly average SBP, month-ahead and day-ahead prices (£/MWh)



4.118. These data indicate a reasonable correlation of 0.62 between month-ahead forward prices and SBPs and a much stronger correlation of 0.91 between day-ahead prices and SBPs. As day-ahead and month-ahead prices also feed into price curves on investment timescales, this suggests that the higher cash out prices under P194 will feed through into forward prices and hence may influence participants' investment decisions.

4.119. We also calculated that P194 would have increased the average level of SBP by £1.50/MWh over the period 1 April 2004 to 30 June 2005. It would have increased the average level of SBP during peak periods by £2.60/MWh. Whether such increases, even assuming they were fully reflected in forward prices, would be sufficient to persuade participants to undertake investments that they would otherwise not have undertaken will, of course, depend on how marginal the investment decisions were. However, it is clear that implementing P194 would not adversely affect long term security of supply and could well improve it.

Table 8: Summary of security of supply impacts[50]

SECURITY OF SUPPLY	Short term impacts	✓✓
	Long term impacts	✓
OVERALL ASSESSMENT	✓✓	

Environmental impacts

4.120. Chapter 3 discussed potential environmental issues arising from the implementation of the modification proposal if it resulted in more plant being part loaded and in relation to distributional impacts.

4.121. As stated in Chapter 3, available evidence suggests that renewable forms of generation, other than wind generation, are no less predictable than other forms of generation. Ofgem considers that it is appropriate for market participants to face the costs associated with the SO undertaking actions to resolve imbalances. The key purpose of the modification is to ensure that the costs imposed by less predictable forms of generation are faced by those generators.

4.122. It should also be highlighted that not all forms of renewable generation display the same characteristics, and the degree to which renewables power stations are able to control their output varies across technologies. If the modification proposal improved the signals to the market, then it would also encourage more flexible forms of generation (including other renewable forms of generation) to provide necessary system support.

4.123. Chapter 3 noted that wind generation may have less capability to balance its position (although there is evidence that also shows that the predictability of wind output over shorter time frames of an hour improves considerably). Ofgem considers that this modification proposal will only be a barrier to entry

[50] See Footnote 3, which applies to all summary tables in this document.

to the extent that the increased costs associated with this proposal will outweigh the benefits that renewable generation receives (through the Renewables Obligation and European Union Emissions Trading Scheme for example). Ofgem considers that this is unlikely to be the case but invites the views of respondents on this point.

Part loading of plant

4.124. Chapter 3 also identified that there could be adverse environmental consequences from the implementation of the modification proposal if it results in more plants operating at part load. If a plant is operating at part load the efficiency of its operation will decrease, and in turn its emissions per unit of output will rise.[51] Such plants will be generating less than if they had been running at full load therefore this 'shortfall' would need to be met by further generation. On the other hand, as discussed in relation to NGET's SO costs, part loading of plant would increase levels of free headroom and could result in a corresponding fall in NGET's requirements for reserve. Therefore, it would only be the case that if the total reserve increased (i.e. market part loading plus NGET reserve) that there would be a net impact.

4.125. In choosing to part load their plant, generators are balancing the opportunity costs of not operating at full output against the costs of having to buy energy in the very short-term markets to cover plant failures or forecasting errors. It may be more efficient in the long run for a few players to hold part loaded plant and use that part-loading flexibility more frequently by selling it where it is profitable. Environmental considerations and the market drivers coincide. Therefore, to the extent that modification proposal P194 results in more efficient use of plant and fuel, total costs could reduce.

[51] See footnote 30.

Summary

4.126. Improved economic signals may provide beneficial impacts to the environment and decisions regarding part loading. There is no evidence to suggest that there will be a material net impact on the environment due to increased part-loading because of offsetting effects on NGET's reserve requirements.

4.127. In relation to the issue of whether distributional impacts on renewable generators may act as a barrier to entry, available evidence suggests that these forms of generation are (save for wind) no more unpredictable than thermal forms of generation. If certain types of renewable generation are more unpredictable than other generation (including renewable forms of generation), it is appropriate for those generators to face the costs this imposes on the system.

Table 9: Summary of environment impacts[52]

IMPACT ON ENVIRONMENT	Part loading/more efficient use of generation	-
	Distributional impacts	-
OVERALL ASSESSMENT	-	

Risks and unintended consequences

Tagging

4.128. The stronger effect that imperfect tagging would have on more marginal prices is one of the main risks that Ofgem has identified. As explained previously, the current tagging rules are seen as proxies for excluding all system actions from the NIV stack, therefore there is a risk that the main price is not always

[52] See Footnote 3, which applies to all summary tables in this document.

reflective of purely energy balancing costs. Under the P194 tagging methodology, any system actions which appear in the PAR would usually constitute a larger proportion of, and therefore have a greater effect on, the cash out price.

4.129. Although our analysis suggests overall that system actions appear to impact cash out prices, in the periods analysed there is limited evidence to suggest that P194 would exacerbate any potential distortion in relation to system buy prices. When the system is long, there may be a bigger impact. Nevertheless, it may be the case that very infrequently system trades may have a large impact on cash out prices and when this occurs the impact can be quite material, as shown in Figure 13.

4.130. On this basis, there are likely to be risks associated with P194 arising from tagging issues. The analysis in this IA does not discount the possibility that 'system actions' would have a more significant influence on cash out prices in some periods under P194 than under the current baseline. As well as distorting prices in those periods, that possibility also has the effect of increasing the risks involved with participating in the BM, and may encourage market players to minimise exposure to the risk of unrepresentative prices by submitting less bids and offers. However, the analysis provides little evidence that P194 would significantly change the effect that 'system actions' would have on cash out prices overall.

Table 10: Summary of risks and unintended consequences[53]

RISKS AND UNINTENDED CONSEQUENCES	Tagging issues	✗ ✗

[53] See Footnote 3, which applies to all summary tables in this document.

Costs of implementation

4.131. Elexon has estimated that the central costs of implementing this proposal would be around £350k for an add-on to an existing release or £630k for a stand-alone release, and that the costs for each market participant would be anywhere between £10k and £200k. Supposing about 30 market participants, this implies costs of between £300k and £6 million, or total costs of between £650k and £6.6 million.

Summary of analysis

4.132. Table 11 below summarises the impact we consider the modification proposal will have on each of the areas discussed in this document.

Table 11: Summary of costs and benefits of the modification proposal[54]

		Issue/area	Net impact of P194	Quantification
ECONOMY AND EFFICIENCY	(i) Are current cash out prices providing signals?	Tagging issues	✗✗	-
		Re-pricing of bids and offers	✓	-
		Reserve	✓	-
		Average versus marginal	✓✓	-
	(ii) Impact of less dampened signals?	SO costs	✓✓	>£2 million
		Change in participants' behaviour	✓✓✓	£13 to £87 (million)
COMPETITION AND DISTRIBUTIONAL IMPACTS	Liquidity		✓	
	Gaming		✗	
	Distributional impacts		✓	

[54] See Footnote 3, which applies to all summary tables in this document.

SECURITY OF SUPPLY	Short term impacts	✓✓	
	Long term impacts	✓	
IMPACT ON ENVIRONMENT	Part loading/more efficient use of generation	-	-
	Distributional impacts	-	-
RISKS AND UNINTENDED CONSEQUENCES	Tagging issues	As above	-
IMPLEMENTATION COSTS	System costs	✗	£350,000[55]
	Per market participant	✗	£10,000-£200,000
OVERALL ASSESSMENT		✓	

[55] This figure is based on implementation as part of an existing planned update to software system this would increase to £630,000 for a stand-alone release

5. Initial conclusions

5.1. Based on the analysis carried out by NGET, Elexon and Ofgem, Ofgem's initial view is that the benefits of modification proposal P194 are likely to outweigh its costs, and, without prejudice to its discretion in deciding whether to approve this modification proposal, it is accordingly minded to direct that the modification be made.

5.2. Ofgem's assessment is that on the evidence presented there is a defect in the current arrangements, namely that current cash out prices provide dampened signals. However, to consider the potential benefits the modification proposal could bring, it has been necessary to assess the reasons why signals are dampened:

- **NGET's reserve contracting:** The prices paid in respect of the provision of reserve by generators can be lower than the market price at times of system stress. These prices feed into cash out prices and can have a dampening impact on them;

- **constraint costs:** these costs are associated with maintaining the reliability and quality of the system and not energy balancing. In some periods the costs of alleviating constraints are feeding into the main imbalance price, which could be affecting the appropriateness of the cash out signals;

- **repricing of bids and offers:** market participants do not appear to be repricing towards the likely marginal balancing cost when the system is under stress, as a result of this the volume-weighted average falls below the marginal price; and

- **average v marginal:** the volume-weighted average derivation of the main imbalance price does not appear to be tending to the marginal price at times of system stress. This is reducing the cost reflectivity of the imbalance price and hence the signals to market participants.

5.3. These factors are not mutually exclusive. Modification proposal P194 is directed principally at the last of these factors and could improve signals by reducing the dampening impact of these factors. Although it is difficult to determine the precise magnitude of each factor, our initial assessment is that the proposal should provide sharper signals at times of system stress. The proposal should also reduce the impact of reserve contracts feeding through into cash out prices and potentially improve incentives to reprice, but is unlikely to resolve (and may exacerbate) constraint issues.

5.4. In reaching this minded to position, Ofgem would highlight that this is a finely balanced initial assessment. Meaningful quantification has been either not possible or not appropriate for many of the criteria upon which the decision is based, and so Ofgem has weighed up the qualitative arguments and the likely outcomes of the modification proposal in order to reach a decision. Although the potential costs, particularly in terms of the risks from current tagging rules are not immaterial, Ofgem considers that the benefits which can be expected for the economic and efficient operation, and the security, of the system, particularly in the longer term, are likely marginally to outweigh such costs. The benefits arise particularly from increased incentives on market participants to balance their own positions, and the corresponding reduction in NGET's residual role.

1. Appendix 1 – Further background

1.1. This appendix provides an additional explanation of the BM and current cash out arrangements and discussion of a number of the most recent and relevant modification proposals in relation to cash out arrangements in electricity.

Balancing mechanism and cash out arrangements

1.2. The BM was designed as a tool to assist National Grid Company plc (NGC) (now know as National Grid Electricity Transmission (NGET), as the System Operator (SO), to keep the Transmission System in balance close to, and in, real time by providing a mechanism to adjust levels of generation and demand through the acceptance of bids and offers submitted to the BM (Electricity Balancing). The SO also uses the BM, amongst other things, to ensure that the system remains within safe operating limits, and that the pattern of generation and demand is consistent with any system transmission constraints (System Balancing). System Balancing actions include, but are not limited to, frequency control and the alleviation of locational constraints. The SO also has commercial freedom to trade in other short term markets and to contract with generators, suppliers and customers to balance the system.

1.3. Under the rules of the BSC, a Party is in a position of imbalance if its notified contract volume does not match its metered volume, i.e. the Party is producing (or consuming electricity) which has not been sold (or bought) and is therefore not covered by contracts. Imbalance settlement, or 'cash out', is designed so that any electricity produced or consumed that is not covered by contracts is paid for at, or charged at, a cost reflective price. The arrangements are designed to target the costs that the SO has incurred in buying and selling electricity to match generation and demand onto those Parties that are in imbalance, i.e. those Parties on behalf of which the SO has taken electricity balancing actions.

1.4. Parties that are 'long' when the market as a whole is 'short' (i.e. generators whose physical output exceeds their contracted volume or suppliers whose

customers' demand is less than their contract volume when total demand on the system is greater than the total supply of generation), are not, in any meaningful sense, contributing to balancing the system (except inadvertently). The same is true for parties who are short when the market is long. Parties with imbalances in the opposite direction to the system can also impose costs on the system (these are the costs associated with the need for a generator or supplier to change its output at short notice) as their contribution to balancing is not guaranteed, requiring the SO to manage the resulting risks.

System and energy balancing

1.5. The distinction between system balancing and electricity balancing is relevant to the discussion of cash out arrangements. System balancing actions are undertaken by the SO on behalf of the system as a whole and are not related to an individual party's energy imbalance over the relevant balancing period, whereas the SO undertakes electricity balancing actions primarily as a result of market participants not balancing their own positions over the relevant balancing period.

1.6. Consequently, the cash out arrangements are designed to target the costs that the SO has incurred in electricity balancing onto those Parties that are in a position of imbalance, i.e. those Parties on behalf of whom the SO has taken electricity or gas balancing actions. The cash out arrangements seek to exclude system balancing costs from the calculation of cash out prices. To do this, certain rules are applied to cash out to "tag out" system trades, thereby removing them from cash out calculations.

1.7. The methodology for separating electricity balancing actions in the BM from system balancing actions is as follows. First, accepted offers/bids with a continuous duration of less than 15 minutes are excluded from consideration (as the balancing period is set at half an hour, parties' electricity imbalance position are measured on a half-hourly basis). Next, all accepted bids/offers of less than 1 MWh are excluded. Then, in situations where accepted offers have Offer prices below the bid prices of accepted bids, arbitrage tagging occurs and

a matching volume of accepted bids and offers for which the offer price is lower than the bid price are excluded. Finally, if the offer stack is greater than the bid stack, offers are excluded in order of descending offer prices until the volume excluded is equal to that of the bid stack and the remaining offers are used to calculate the main price (If the bid stack is greater than the offer stack, then the cheapest bids are excluded until the offer stack volume has been reached and the remaining bids set the main price).[56]

Residual Cashflow Reallocation Cashflow

1.8. The cash out arrangements are not designed to recover NGET's balancing costs. Instead, the cash out arrangements relate to cashflows associated with market participants' energy imbalance volumes. As outlined above, Parties that are short are charged SBP for their imbalance volumes and Parties that are long receive SSP for their imbalance volumes. Imbalance revenues received from those in short positions feed into a central fund, while imbalance payments to those in long positions are made from the same fund. However, it is unlikely for the imbalance payments and revenues to match and consequently an imbalance cashflow surplus or deficit exists for each balancing period. The net surplus/deficit resulting from summing the imbalance payments and revenues for all market participants is returned to/recovered from market participants via Residual Cashflow Reallocation Cashflow (RCRC).

1.9. The RCRC in each settlement period is allocated to each energy account prorated on the basis of the values of the energy volumes credited to each energy account. The pro-rated proportion to be allocated to each energy account is the Residual Cashflow Reallocation Proportion (RCRP), which is multiplied by the Total Residual Cashflow (TRC) to give each energy account's RCRC. The RCRC values are then summed over the energy accounts of each party, and summed across all settlement periods to give the daily RCRC.

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[56] For further information on tagging rules refer to appendix 2 of "Electricity and gas cash out review – a consultation document", Ofgem, May 2004

Modification proposals relating to cash out arrangements

1.10. During the design of NETA, Ofgem/DTI, in consultation with interested Parties, considered whether cash out prices should be calculated using a marginal or volume weighted average methodology. After extensive consultation and discussion, Ofgem/DTI concluded that marginal cash out pricing had a number of drawbacks relative to a volume weighted average approach. For instance, since at the time of the introduction of NETA, Gate Closure was set 3.5 hours ahead of real time, following which participants could not revise their bids or offers, it was the view of Ofgem/DTI that there would be a significant risk that marginal prices would be set by unrepresentative actions (for example, a high priced Offer accepted by the SO early in the trading window). More generally, Ofgem/DTI had concerns that, based in part upon previous experience of Pool pricing, a marginal pricing approach could be vulnerable to manipulation and could lead to greater volatility in cash out prices and prices that frequently reflected neither underlying market conditions nor the costs incurred by NGC in balancing the system.

1.11. Since NETA Go-Live, in the light of experience gained under the new arrangements, a number of modifications have been made to the way in which Energy Imbalance Prices are calculated as a result of concerns that the rules did not give rise to prices that reflected costs and market fundamentals on the grounds that the proposed changes would increase the likelihood of this happening. These modifications include the introduction of the Continuous Acceptance Duration Limit ("CADL") and changes to the treatment of contracts in the calculation of the Energy Imbalance Price. Approved Modification P78 was introduced to address a potential defect in the methodology for calculating Energy Imbalance Prices used at that time which resulted in high levels of SBP that were considered to be driving the market long, as discussed above.

Modification Proposal P78

1.12. Approved Modification P78 was submitted by NGC on 5 April 2002 in response to concerns expressed by both NGC and market participants that cash out prices were reflective of costs associated with both System Balancing and Electricity Balancing. It was also suggested that SBP was being distorted by System Balancing costs more frequently than SSP and hence that the spread between SBP and SSP was larger than would be the case if System Balancing costs were correctly excluded. This, in turn, was creating asymmetric risks for Parties, in response to which they were tending to go long to avoid exposure to a high SBP, with the result that the market itself was long overall.

1.13. Approved Modification P78 introduced a mechanism into the BSC to remove a category of acceptances taken for System Balancing reasons from the calculation of cash out prices. Under Approved Modification P78 these acceptances were considered to be characterised by equal and opposite compensatory actions which, in general, were being taken by the SO for System Balancing reasons, for instance the alleviation of network constraints.

1.14. Approved Modification P78 also sought to change the derivation of cash out prices such that there would be a 'main' price and a 'reverse' price. It proposed that the reverse price would be derived from a market price based on short-term energy trades made in the forward and spot markets. The main price would be derived using a volume weighted average of all the eligible Electricity Balancing actions taken by the SO to alleviate the Net Imbalance Volume ("NIV"). Under the proposal the main price would apply to imbalances in the same direction as the imbalance of the System and the reverse price would apply to imbalances in the opposite direction. On 9 September 2002, the Authority decided to direct that Approved Modification P78 should be made. Approved Modification P78 was implemented on 11 March 2003.

1.15. As part of its decision, Ofgem highlighted that it considered that the principle behind the current dual cash out mechanism continued to be appropriate. Participants who are spilling electricity should receive a lower price for their electricity than if they had been fully contracted since they may be imposing

costs on the system. Conversely, participants on whose behalf the SO has to procure the flexible delivery of electricity at short notice should pay the full cost of power delivered over short timescales.

1.16. Ofgem requested further information from NGC on the frequency with which System Balancing actions affect the reverse price and the impact that they have on Energy Imbalance Prices. Ofgem accepted NGC's advice that the costs of System Balancing actions are being included in the calculation of Energy Imbalance Prices. Ofgem considered that the change under P78 would help make cash out more reflective of the cost of electricity balancing and this would facilitate the achievement of the applicable BSC Objective of "promoting effective competition in the generation and supply of electricity, and (so far as consistent therewith) promoting such competition in the sale and purchase of electricity".

1.17. Under original Modification Proposal P78, the reverse price is based on a market price. Ofgem considered that this would have the impact of enhancing incentives for Parties to balance their own positions. Ofgem highlighted that enhanced incentives to balance will increase the level of competition by encouraging parties to trade ahead of Gate Closure, facilitating applicable BSC objective of "promoting effective competition in generation and supply electricity.." and reduce the costs incurred by NGC in balancing the system.

Modification Proposal P135

1.18. During autumn 2003 the Authority also considered the issues raised in respect of Modification Proposal P135 raised by NGC , which proposed that the Energy Imbalance Price calculation be amended such that SBP is calculated using a marginal methodology during periods of demand control and where the System is short (i.e. where there is insufficient generation to meet demand). Modification Proposal P135 was raised by NGC (and granted urgent status) as an 'interim measure', ahead of raising what it considered to be a more enduring long term solution with Modification Proposal P136.

1.19. The Authority rejected Modification Proposal P135 on grounds that it would not better facilitate achievement of the Applicable BSC Objectives. This decision was reached for a number of reasons which included concerns that by having two regimes in place for the calculation of Energy Imbalance Prices there would be scope for perverse incentives to exist and also that there could be increased risk that cash out prices were set at levels that did not reflect NGC's costs on the basis of a very small volume offer. In addition, Ofgem considered that the incentives that would be created by the RCRC mechanism could also undermine the intended effect of the Modification proposal and that there was a significant risk that the Modification proposal could increase the risk of generators inefficiently part-loading or withholding capacity in the event that demand control was likely.

1.20. As part of the Authority's decision letter on Modification Proposal P135, Ofgem highlighted several areas where it considered potential improvements could be made in respect of the Energy Imbalance Price calculations. These areas included:

- Continuous Acceptance Duration Limit ("CADL") tagging;
- NIV tagging;
- NIV volume;
- +/-£99,999/MWh bid and offer price constraint; and
- Ensuring that correct incentives are in place on suppliers if demand control is instructed.

Modification Proposals P136 and 137

1.21. Modification Proposal P136 was submitted on 1 August 2003 by NGC. In its Proposal, NGC considered that the use of a volume weighted average methodology for the calculation of the main cash out price significantly understates the cost of the marginal balancing action. Further, it considered that this understatement is particularly significant at times of energy shortage

(i.e. high levels of demand relative to generation availability) when the marginal cost of balancing energy is likely to be high. NGC was of the view that the use of a volume weighted average methodology to calculate the main cash out price has meant that these prices have failed to reflect the true underlying marginal cost of balancing and thus have not provided market participants with sufficient incentives to contract ahead in the forward energy markets to mitigate the risk of not being able to achieve a balanced position at Gate Closure.

1.22. Modification Proposal P137 was submitted on 1 August 2003 by Barclays Bank Plc. In its proposal, Barclays considered that the current method of calculation of the main cash out price fails to reflect the underlying costs of market shortage, and in particular that a volume weighted average definition of the main cash out price underestimates the marginal cost of balancing at times of shortage.

1.23. Barclays was also of the view that the current NIV tagging methodology inappropriately tags out accepted offers at times of system shortage, as the need to maintain operating reserves would result in NGC also accepting bids in the BM at this time, which will result in the most expensive offers being tagged out. In addition, it considered that the current methodology used to include the costs that NGC incurs in procuring and using reserve into cash out prices was flawed. Barclays argued that the existing methodology does not reflect the opportunity cost of using this reserve when it is called because the option fees paid for reserve are averaged over the Settlement Periods for which the reserve is made available, rather than those Settlement Periods in which the reserve is actually used. Further, it was of the view that the current derivation of SBP does not account for the use of non BM Unit specific standing reserve.

1.24. Each of Modification Proposals P136 and P137 sought to modify the BSC to introduce a marginal methodology for the calculation of the main cash out price. Under each Modification Proposal the marginal price would be derived from the last eligible electricity balancing action remaining in the NIV, i.e. the most expensive offer acceptance or electricity BSAD purchase when the system

is short, and the least expensive bid acceptance or electricity BSAD sale when the system is long.

1.25. NGC, the Proposer of Modification Proposal P136, was of the view that using a marginal methodology for the calculation of the main cash out price would provide a more appropriate price signal to the market as to the underlying cost of supplying the last increment of energy required to balance generation and demand. The Proposer considered that a more appropriate price signal would place incentives on market participants to contract ahead in the forward energy markets to mitigate the risk of not being able to achieve a balanced position at Gate Closure, which in turn would benefit the operation of the Transmission System when security of supply is an issue and would increase the level of competition in the market.

1.26. The Authority rejected Modification Proposals P136 and P137 on the grounds that it would not better facilitate achievement of the applicable BSC objectives. While Ofgem acknowledged that strong views were expressed both for and against the introduction of marginal imbalance pricing, on balance Ofgem was of the opinion that neither Modification Proposal would be economic and efficient on the basis that they would lead to non cost-reflective pricing. Furthermore, on the basis that that the Modification proposal may not be effective in targeting NGC's costs back on to BSC Parties, Modification Proposals P136 and P137 would not better facilitate competition in that they would increase costs to, and risks on, market participants.

Modification Proposal P144

1.27. Following this, Modification Proposal P144 'Removal of CADL from the BSC' was raised and granted Urgent status. The Authority issued its decision letter to reject Modification Proposal P144 on 18 December 2003 on grounds that it would not better facilitate achievement of the Applicable BSC Objectives. This decision was reached on the basis that CADL tagging is an appropriate mechanism for identifying balancing actions taken to address within-half-hour effects (such as frequency control) and that this mechanism complements the

NIV tagging mechanism in achieving the best differentiation between System Balancing and Electricity Balancing actions.

1.28. As in the Authority's decision letter on Modification Proposal P135, in the decision letter for Modification Proposal P144 Ofgem made clear that it considered that, where there are potential improvements to be made in respect of the Energy Imbalance Price calculations, it is important for the industry to address these issues in the appropriate forum and, if any perceived defects are identified, for resolution of these defects to be progressed as quickly as possible.

2. Appendix 2 – ELEXON cashflow analysis

CORWG – P194 REGULATORY IMPACT ASSESSMENT ANALYSIS

1. Background

An argument was expressed during the Modification Procedures for P194 – 'Revised Derivation of the "Main" Energy Imbalance Price' (P194) that, if approved, there would be a disproportionate adverse financial impact on certain Party types. In addition, it was suggested that P194 would encourage 'excessive' length in the market by encouraging Parties to take net long positions to avoid exposure to System Buy Price.

Ofgem indicated that, in order to quantify these perceived impacts for the purpose of its Regulatory Impact Assessment, it would be useful to consider the financial impact on different categories of Parties based on historic data. It was suggested that the net financial impact on each participant could be estimated, this would then be considered in the context of participant size and imbalance exposure in order to quantify the extent to which the financial impact of P194 may be disproportionate. Consideration of the impact on participants in terms of their annual net imbalance position could also help to illustrate whether P194 would be likely to encourage 'excessive' length in the market.

2. Approach

The following approach was used to estimate the impact on participants by size and imbalance exposure.

- Historic data in the period 1 April 2004 – 31 March 2005 was considered;
- Energy Imbalance Prices that would have been calculated using the P194 methodology were estimated for each Settlement Period;
- Revised Imbalance Charge and Residual Cashflow Reallocation Cashflow (RCRC) values were calculated for each Energy Account in each Settlement Period considered;
- For each BSC Party ID, the Party Total Absolute Energy Imbalance Volume and Party Total Absolute Credited Energy were calculated for the period considered. These values were compared to give a Percentage Imbalance for each Party in the period considered.
- The net annual financial impact of P194 on each Party in the time period considered was calculated in terms of Imbalance Charges and RCRC. Values were divided by the Party Total Absolute Credited Energy in the period considered to give costs per unit Credited Energy (this approach was utilised to give values which could be compared between Parties of different sizes);
- For each BSC Party, the Party Total Absolute Credited Energy and the Market Total Absolute Credited Energy were compared to give a Percentage Market Share;
- Parties were classified as either Net Generators or Net Suppliers on the basis of their Net Credited Energy over the period considered;
- High level cashflow data was considered to illustrate the potential order of magnitude impact of P194 on industry cashflows; and
- The following relationships were investigated:

a. **Net cost of P194 per unit Credited Energy Vs Market Share**: Consideration of the net cost of P194 as a consequence of changes in Imbalance Charges and RCRC relative to Market Share was intended to show any correlation between whether P194 is likely to benefit a Party and the size of that Party.

b. **Net cost of P194 per unit Credited Energy Vs Proportion of Credited Energy exposed to Imbalance Charges:** Consideration of the net cost of P194 per unit Credited Energy as a consequence of changes in Imbalance Charges and RCRC was intended to show whether P194 would provide an increased incentive to balance. It should be expected that there would be a correlation between the net cost of P194 and the proportion energy exposed to Imbalance Charges, unless other factors (such as the effect of the RCRC) are acting to distort any increased incentive to balance provided by P194.

c. **Proportion of Credited Energy exposed to Imbalance Charges Vs Market Share**: Consideration of the proportion of Credited Energy Exposed to Imbalance Prices against Market Share was intended to support consideration of whether there is any correlation between the extent a Party is exposed to changes in Energy Imbalance Prices and participant size.

d. **The impact on Net Generators and Net Suppliers:** Consideration of the net cashflow between those Parties which were Net Generators and those which were Net Suppliers should support consideration of whether either area of the market is likely to be detrimentally affected by P194.

e. **Proportion of imbalance associated with Net Generators and net Suppliers:** Consideration of the proportion of the market total absolute imbalance volume associated with Net Generators and Net Suppliers was intended to support consideration of whether Net Suppliers or Net Generators are exposed to changes in Energy Imbalance Prices to a greater extent.

f. **Net cost of P194 per unit Credited Energy VS Net Imbalance Position:** Consideration of the extent a Party benefits or is financially adversely affected by P194 against net imbalance volume over an extended period was intended to support consideration of whether there is likely to be an increased incentive to be consistently long or short under P194.

It should be noted that no attempt was made to account for changes in participant behaviour. As such, the analysis provides a view of the financial impact of P194 in comparison to the current baseline if applied historically with no opportunity for participants to respond to the changes in pricing signals. Since it must be assumed the market would respond to any change in the calculation of Energy Imbalance Prices, the figures involved do not provide any indication of the actual financial impact were P194 to be implemented. However, the analysis does support consideration of the overall trends that would be likely to occur.

It should be noted that some BSC Party IDs have not been included in the results, for example inactive IDs (where there were no cashflows in the periods considered) and Party IDs where it appeared the energy was being reallocated to an energy account of another Party.

TABLE 1: ANNUAL SUMMARY

Area	Value	Commentary
Percentage of Credited Energy exposed to Imbalance Prices	**2.24%**	The Market Total Annual Absolute Credited Energy was 621,000 GWh, the Market Total Annual Absolute Imbalance Volume was 13,900 GWh.
Total increase in Party Annual Net Imbalance Charges	**£32m**	Over the year considered, the Party Annual Net Imbalance Charge summed across all Parties increased by £32m. This represented an approximate increase of 30% in the Annual Net Imbalance Charge cashflow for the market. The increase in Imbalance Charges resulted in a corresponding £32m increase in the RCRC, this represented an increase of approximately 630%.
Largest increase in Annual Net Imbalance Charges for any Party	**£4.4m**	£4.4m was the largest increase in Annual Net Imbalance Charges for any individual Party, representing an increase of approximately 37%. It should be noted that, as a consequence of changes to the RCRC, this Party actually received an overall net benefit.
Largest Annual Net RCRC benefit	**£4.9m**	The Party with the largest annual benefit via RCRC received a net benefit of £4.9m, £4.4m of this benefit was offset by increases in Imbalance Charges.
Largest Annual Net Dis-benefit	**£1.95m**	The Party with the largest Annual Net Dis-benefit (via RCRC and Imbalance Charges) received a net charge of £1.95m under P194 as compared to the current baseline (this represented a 34% change in annual cashflow). This Party had a Market Share of roughly 5% and contributed 9.6% of the Market Total Absolute Imbalance Volume. The Party was net long during the period considered.
Largest Annual Net Dis-benefit per unit Credited Energy	**£4.19 /MWh**	The Party with the largest Annual Net Di-benefit received a net charge of £4.19/MWh per unit Party Total Absolute Credited Energy under P194 as compared to the current baseline. This Party received an Annual Net Charge per unit Absolute Credited Energy of £44.33/MWh under the current baseline. This Party was net short during the period considered and had 100% of its Credited Energy exposed to System Buy Price.
Largest Annual Net Benefit	**£1.93m**	The Party with the largest Annual Net Benefit (via RCRC and Imbalance Charges) received a net payment of £1.93m under P194 as compared to the current baseline. This Party had a Market Share of 12% and contributed 6.8% of the Annual Market Total Absolute Imbalance Volume.
Largest Annual Net Benefit per unit Absolute Credited Energy	**£0.18/MWh**	The Party with the largest Annual Net Benefit per unit Credited Energy received a net benefit of £0.18/MWh under P194 as compared to the current baseline.

Chart 1:

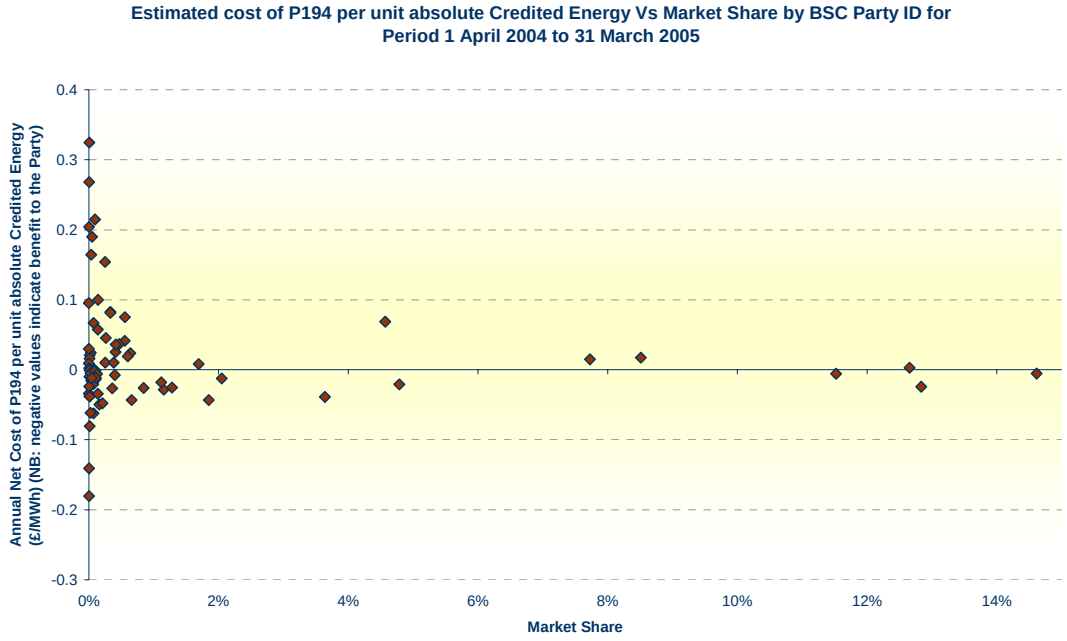


Chart 1 above shows the relationship between the Annual Net Cost of P194 per unit Credited Energy and Market Share by BSC Party ID. The Annual Net Cost of P194 per Unit Credited Energy is taken to be the net impact of changes in RCRC and Imbalance Charges over a period of one year for the Party divided by that Party's absolute Credited Energy in each Settlement Period summed over the year. A Party's Market Share is taken to be that Party's absolute Credited Energy in each Settlement Period summed over the year divided by the total of all Parties' absolute Credited Energy in each Settlement Period summed over the year.

Some Parties with a large Market Share benefited from P194, whilst others with a comparable Market Share received a net charge under P194. Likewise, some Parties with a small Market Share benefited whilst others received a net charge. Hence from this data, there appears to be no clear correlation between a Party's Market Share and whether or not P194 that Party was likely to receive a financial benefit over the period considered.

It is considered that the following conclusions can be drawn from Chart 1:

- **P194 can act as either a benefit or a dis-benefit to any individual Party;**
- **There is no clear correlation between whether P194 is a benefit or a disadvantage and a Party's Market Share.**

Chart 2:

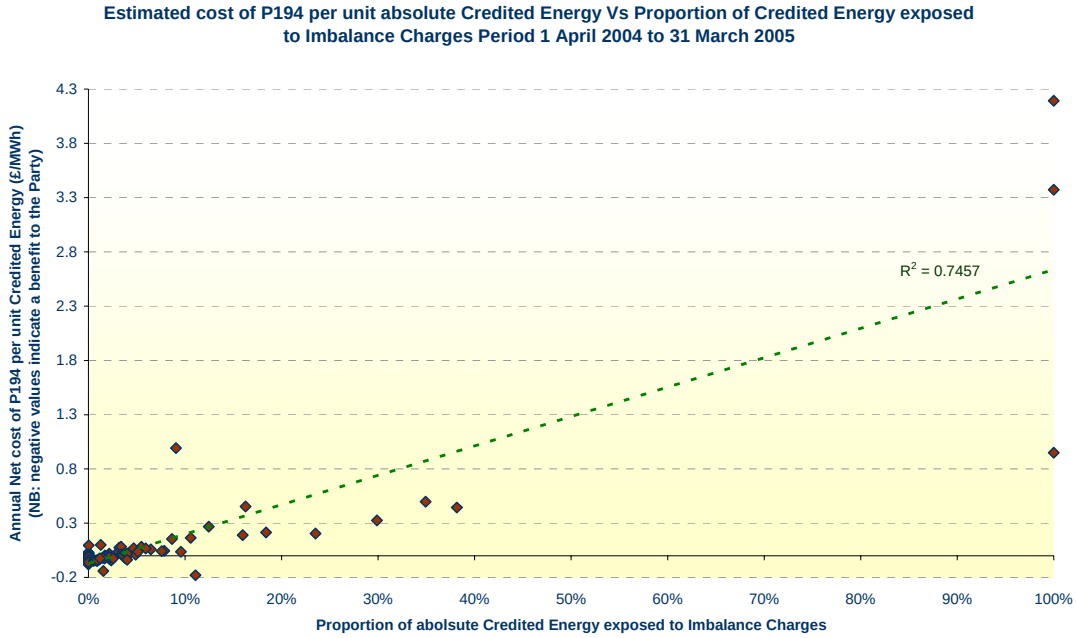


Chart 2 shows the relationship between the Net Cost of P194 per unit Credited Energy under P194 (as explained under Chart 1) and the proportion of a Party's Credited Energy exposed to Imbalance Charges. The proportion of a Party's Credited Energy exposed to Imbalance Charges is taken to be the Party's absolute Imbalance Volume in each Settlement Period summed over the period considered divided by that Party's absolute Credited Energy in each Settlement Period summed over the year. Since Imbalance Volumes are treated as absolute, all Imbalance Volumes contribute positively to the calculation of a Party's proportion of Credited Energy exposed to Imbalance Charges (i.e. there is no netting of imbalance volumes between Settlement Periods).

The data shows that participants with a larger proportion of their energy exposed to Imbalance Charges during the period considered were more likely to be adversely financially impacted by P194. Those Parties with a smaller proportion of energy exposed to Imbalance Charges are more likely to benefit (as consequence of net increases in the RCRC). Therefore, the analysis indicates that there is a correlation between the net cost of P194 and the proportion of energy exposed to Imbalance Charges. This would be expected as P194 increases (or does not change) Energy Imbalance Prices relative to the current baseline; therefore it would be expected to have an adverse financial impact on those Parties with a larger exposure to Imbalance Charges. However, the analysis also appears to illustrate the financial incentives provide by an increase in Imbalance Charges would not distorted by the increase in the RCRC.

The data highlights that a number of participants had a 100% of their energy exposed to Energy Imbalance Prices during the period considered. Parties with 100% of their energy exposed to Energy Imbalance Prices had a combined Market Share of 0.0014% and contributed 0.0639% of the Market Total Absolute Imbalance Volume. These Parties were subject to the largest adverse financial impact per unit Credited Energy in the period considered.

It is considered that the following conclusions can be drawn from Chart 2:

- **The net cost of P194 per unit Credited Energy is proportional to the percentage of a Party's Credited Energy exposed to Imbalance Charges**
- **Parties with a large proportion of their Credited Energy exposed to Imbalance Charges are likely to be adversely impacted financially due to net increases in Imbalance Charges under P194; and**
- **Parties with a small proportion of their Credited Energy exposed to Imbalance Charges are likely to benefit financially due to a net increase in the RCRC under P194.**

Chart 3:

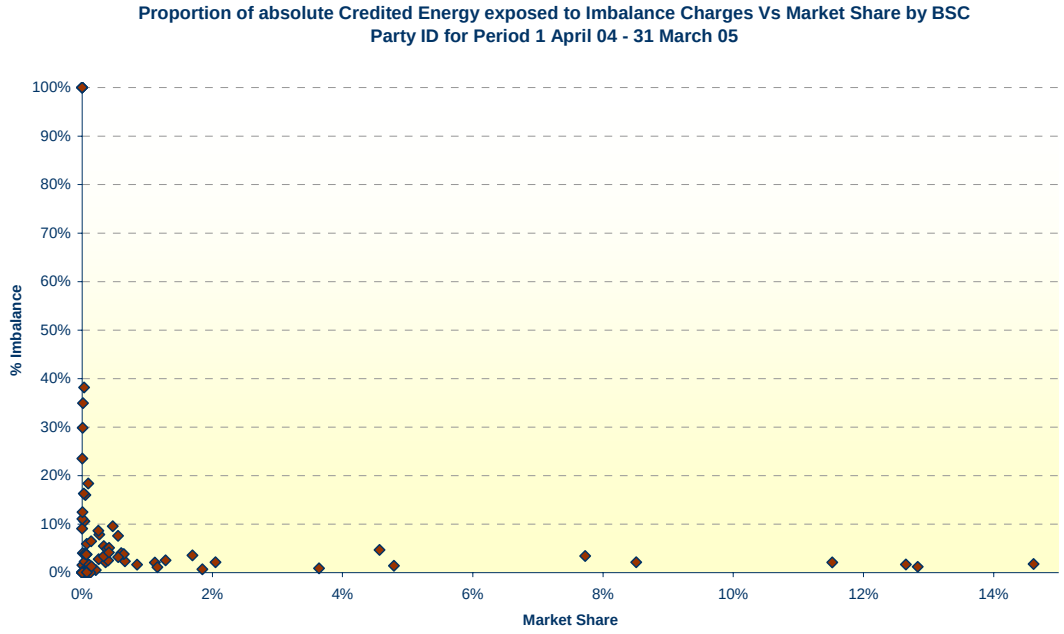


Chart 3 illustrates the relationship between Party's Market Share and the proportion of Credited Energy exposed to Imbalance Charges in the period considered (the derivation of these values is explained for Graphs 1 and 2).

The analysis shows that, in general, Parties with a smaller Market Share are more likely to have a larger than average proportion of their credited energy exposed to Energy Imbalance Prices. Consequently, as illustrated in Chart 2, it appears that small Parties are more likely to be adversely financially impacted by P194.

It is considered that the following conclusions can be drawn from Chart 3:

- **Parties with a smaller Market Share are more likely to have a larger proportion of their Credited Energy exposed to Imbalance Charges.**

Generation - Supply comparison:

Area	Result
Total Annual Net Cost of P194 (in terms of increases in Imbalance Charges and changes to the RCRC) to Parties that were Net Generators in the period considered (NB: negative value indicates a net benefit).	**-£3.5m**
Proportion of Market Total Annual Absolute Imbalance Volume associated with BSC Parties that were Net Generators in the period considered	**30%**
Total Annual net cost of P194 to Parties that were Net Suppliers in the period considered	**£3.5m**
Proportion of Market Total Annual Absolute Imbalance Volume associated with BSC Parties that were Net Generators in the period considered	**70%**

For each Party the Credited Energy for each Settlement Period was summed across the period considered to give the Party's Net Credited Energy. Where a Party's Net Credited Energy was positive the Party was considered a Net Generator. Where a Party's Net Credited Energy was negative the Party was considered a Net Supplier. The Annual Net Cost of P194 was summed across all Net Generators to give the Total Annual Net Cost of P194 to Parties that were Net Generators (likewise for Net Suppliers). Party Absolute Imbalance Volumes were summed across all Net Generators; this was then divided by the Absolute Imbalance Volume summed across all Party's to give a proportion of Market Total Imbalance Volume associated with Net Generators (likewise for Net Suppliers).

The analysis indicates that, during the period considered, P194 provided a cashflow from Net Suppliers to Net Generators of the order of ~£3.5m per annum. It also illustrates that a greater proportion of the Market Annual Total Absolute Imbalance Volume during the period considered was associated with Net Suppliers than Net Generators.

It is considered that the following conclusions can be drawn from the data above:

- **Net Generators are likely to financially benefit from P194;**
- **Net Suppliers are likely to be adversely financially affected by P194; and**
- **Net Suppliers are associated with a larger proportion of the total market imbalance than Net Generators.**

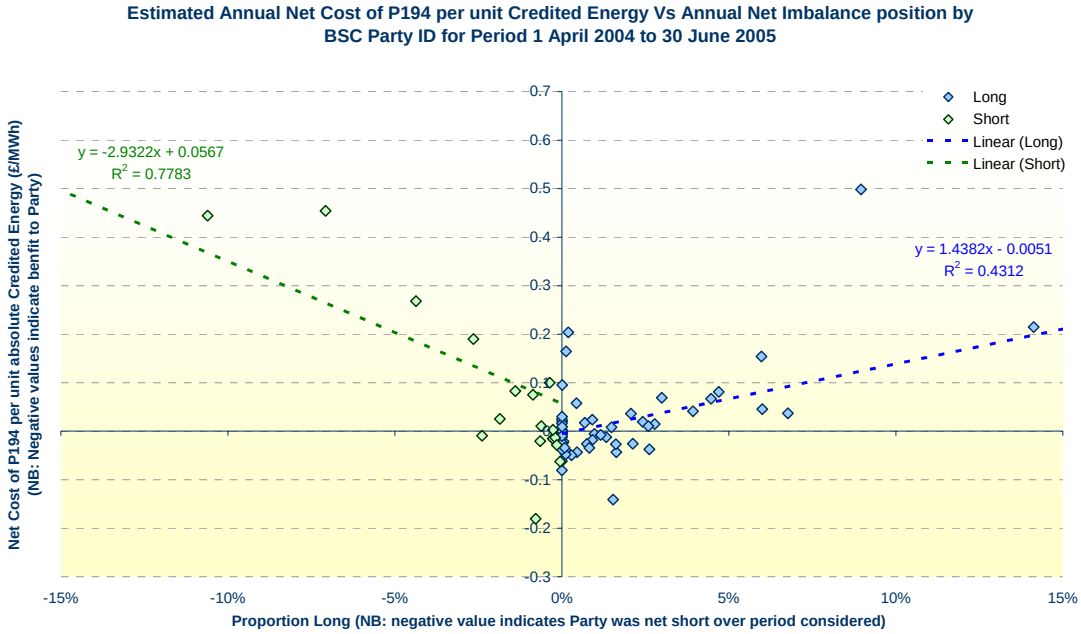
Results: Market Length

Area	Value
Annual net imbalance volume over period considered.	**4,700 GWH (long)**
Proportion of Parties Net Long	**72%**
Total net increase in annual Imbalance Charges for Parties that were Net Long in the period considered	**£26m**
Proportion of Parties that were Net Short in the period considered	**28%**
Total net increase in annual Imbalance Charges for Parties that were Net Short in the period considered	**£6m**

The market was net long over the period considered. The majority of Parties (72%) had a net positive imbalance volume over the year considered (i.e. were net long).

Those Parties that were net long were subject to an increase in Imbalance Charges of £26m over the period considered. Those Parties that were net short were subject to an increase in Imbalance Charges of £6m over the period considered.

Chart 4:



Graph 4 above shows the relationship between the Annual Net Cost of P194 (via Imbalance Charges and RCRC) and a Party's net imbalance position over the period considered. The Proportion Long value for a Party was derived by dividing the sum of Settlement Period Imbalance Volumes over the period considered (i.e. the Party's annual net imbalance volume) by the Party's Annual Total Absolute Credited Energy. Where a Party had a net long position in the period considered it has a positive value as its Proportion Long. Likewise, a Party that had a net short position will have a negative percentage as its Proportion Long value. Smaller magnitude percentages indicate a Party that was either generally balanced or was long to a similar extent to being short over the period considered (since Imbalance Volumes are not

taken as absolute and therefore net between Settlement Periods). The data is split between those Parties that were net long and those Parties that were net short in order to allow trends to be established separately.

The data shows that participants that were net short during the period considered were more likely to be adversely financially impacted by P194 (All Parties that were net short by more than 3% of their Absolute Credited Energy received a net charge under P194 relative to the current baseline). Likewise participants that were net long during the period considered were more likely to be adversely financially impacted by P194 (All Parties that were net long by more than 3% of their Absolute Credited Energy received a net charge under P194 relative to the current baseline). Those Parties with a smaller proportion of energy exposed to Imbalance Charges are more likely to benefit. Therefore, the analysis indicates that P194 is likely to increase the financial incentive for Parties to avoid consistently being either long or short.

Comparison of the gradients of the liner trend lines for net long and net short Parties appears to show that the incentive to avoid being consistently short over the period considered would be increased to a greater extent than that for being generally long. It appears feasible that this would encourage Parties to avoid being generally short and therefore aim to be generally slightly long. However, the increased incentive to avoid being generally long is likely to encourage Parties to minimise the extent to which they are generally long.

These results are to be expected since P194 will increase (or not impact) the main energy Imbalance Price. Therefore, participants that were long when the System was net long will be paid less via Imbalance Charges due to a lower System Sell Price. Likewise, Participants that were short when the System was net Short will pay less via Imbalance Charges due to an increase in System Buy Price. Hence, any Party exposed to the main Energy Imbalance Price will be subject to increased Imbalance Charges under P194 relative to the current baseline.

It is considered that the following conclusions can be drawn from the analysis performed:

- **P194 provides an increased incentive to avoid being generally short that is proportional to the extent a Party is net short;**
- **P194 provides an increased financial incentive to avoid being generally long that is proportional to the extent a Party is net long; and**
- **The incentive to avoid being generally short would be increased to a greater extent than the incentive to avoid being generally long.**

3. Conclusions

The high level conclusions drawn from the results in the following section are summarised below.

Cashflows

In comparison to the current baseline P194 is likely to have a material impact on annual Imbalance Cashflows and consequently the RCRC, with the Total Market Annual Net Imbalance Charges increasing by approximately £30m over the period considered. At a participant level the impact is also potentially substantial, with participants being subject to an average net annual increase in Imbalance Charges of approximately 20% based on historic data. It is worth noting that Imbalance Charge cashflows involved remained of similar orders of magnitude, however the impact on the RCRC was more substantial.

Small Parties

Parties with a large proportion of their Credited Energy exposed to Imbalance Charges are likely to be adversely impacted financially due to increases in Imbalance Charges under P194. Parties with a smaller Market Share are more likely to have a larger proportion of their Credited Energy exposed to Imbalance Charges. Hence, small Parties are more likely to be adversely impacted by P194 as a consequence of having a larger proportion of their Credited Energy exposed to Imbalance Charges.

Generation Vs Supply

Parties with a large proportion of their Credited Energy exposed to Imbalance Charges are likely to be adversely impacted financially due to increases in Imbalance Charges under P194. Net Generators generally have a smaller proportion of Credited Energy exposed to Imbalance Charges. Net Suppliers generally have a larger proportion of Credited Energy exposed to Imbalance Charges. Therefore, Net Generators are likely to financially benefit from P194 and Net Suppliers are likely to be adversely financially impacted by P194.

Net Position

P194 is likely to provide an increased incentive to avoid being generally short that is proportional to the extent a Party is net short. P194 is likely to provide an increased financial incentive to avoid being generally long that is proportional to the extent a Party is net long. Therefore, P194 is likely to increase the financial incentive to avoid either being consistently long or consistently short (i.e. having either a net positive or net negative imbalance volume over an extended period). The incentive to avoid being consistently short is likely to be increased to a greater extent than that for being generally long.

3. Appendix 3 – Derivation of potential balancing cost benefit

3.1. The range of potential balancing cost benefits was derived from an analysis of a limited sample of periods for which NGET provided data that enabled us to calculate the effect of changes in participant behaviour. The dataset consisted of 14 periods during which the system was short and 16 periods during which the system was long.

3.2. We calculated the effect on balancing costs of participants choosing to go 5 percent and 10 percent longer, as measured by the volume of actions that NGET would have had to take. In periods when the system was short, we assumed that reducing the volume of offers (hence making the system less short) that NGET had to take with one scenario assuming that the 5 and 10 percent reduction in offers would have no impact on the volume of bids it had to take.

3.3. In the second scenario it was assumed that above scenario (of a 5 or 10 percent reduction in offers) occurs in combination with a 50 percent reduction in the volume of bids by change in the volume of offers accepted. This is on the grounds that some of the bids and offers previously accepted would have been to create reserve and there would be less need for this if the system was longer. When the system was long, and the volume of bids accepted was increased, we assumed that there was no change in the volume of offers accepted.

3.4. We then calculated the average and maximum change in the balancing costs (as measured by the change in the net costs of accepted bids and offers) for the periods analysed. Hence, a maximum and average per period 'benefit' was calculated. This is shown in Table 12 below.

Table 12: Estimating per period impact of 5% or 10% reduction in NIV

		5% reduction in offers (system short) or increase in bids (longer)		**10% reduction** in offers (system short) or increase in bids (longer)	
Change in net balancing costs per period (£)		**A**. No change in reverse volume	**B**. Change in reverse volume	**C.** No change in reverse volume	**D**. Change in reverse volume
Average impact	Short [1]	-2,225	-1,041	-4,478	-2,083
	Long [2]	-682		-1,363	
Maximum impact	Short [3]	-6,841	-6,171	-13,682	-12,342
	Long [4]	-1,218		-2,343	

3.5. The results of this analysis are summarised in Table 12. The above table shows the different scenarios considered. For example, if the modification proposal P194 resulted in NIV being reduced 5% the average expected impact when the system is short [1], the impact is calculated to be £2,225 reduction in costs of balancing per period (with no change in the reverse volume) or £1,041 if there is a change in the reverse volume.

3.6. To estimate an annual impact, we converted these average and maximum values per period into annual figures based on the number of periods in 2004/05 during which the system was short and long and then multiplying by

the corresponding calculation from the analysis above. The results of this analysis are summarised in the table below.

Table 13: Estimating per period impact of 5% or 10% reduction in NIV

Change in balancing costs per year (£ million)[57]		**5% reduction** in offers (system short) or increase in bids (longer)		**10% reduction** in offers (system short) or increase in bids (longer)	
		A. No change in reverse volume	**B**. Change in reverse volume	**C.** No change in reverse volume	**D**. Change in reverse volume
Average impact	Short [1]	-9	-4	-18	-8
	Long [2]	-9		-19	
Maximum impact	Short [3]	-27	-24	-54	-48
	Long [4]	-17		-33	

3.8. The above table therefore provides a range of possible annual impacts if modification proposal P194 were to impact on the number of balancing actions necessary. The cells shaded blue in this table show the combination of impacts that would yield the smallest annual impact taking into account the

[57] Based on 2004/05 data – the number of periods when system short = 3,921 and 13,599 periods when system was long

number of periods when the system is long and short. The cells shaded yellow in this table show the combination that yields the largest annual impact.

3.9. On this basis the analysis above, estimates a range of benefits between £13 million and up to £87 million if the modification proposal resulted in changes to the NIV as modelled above.

4. Appendix 4 – Gas and electricity market interactions

4.1. Figure 26 below summarises the events in the electricity market over the period 26 December 2005 to 01 January 2006. NGET issued a Notice of Insufficient Margin on 28 December 2005. Based on the unavailability of some generators,[58] NGET estimated a shortfall in its reserve requirements of 1.7 GW and therefore issued an HRDR notice in the morning of 29 December 2005 relating to the evening peak. NGET continued to assess the situation and following response from generators eventually removed HRDR towards the end of the evening peak.

4.2. Figure 26 also shows the main imbalance price that applied during the period and NGET's calculations of what the main imbalance price would have been if either a pure marginal or a PAR 100 derivation had been used over this period. For 29 December 2005, there is a large difference between the main imbalance price and what the price would have been based on either marginal pricing methodology (NB: the PAR100 price would have been so similar to the full marginal price over this period that it is difficult to see in the figure).

[58] The declared availability of generators based on maximum export limits ('MEL') was around 56.5 GW. Earlier in December, MEL has been as high as 65 GW.
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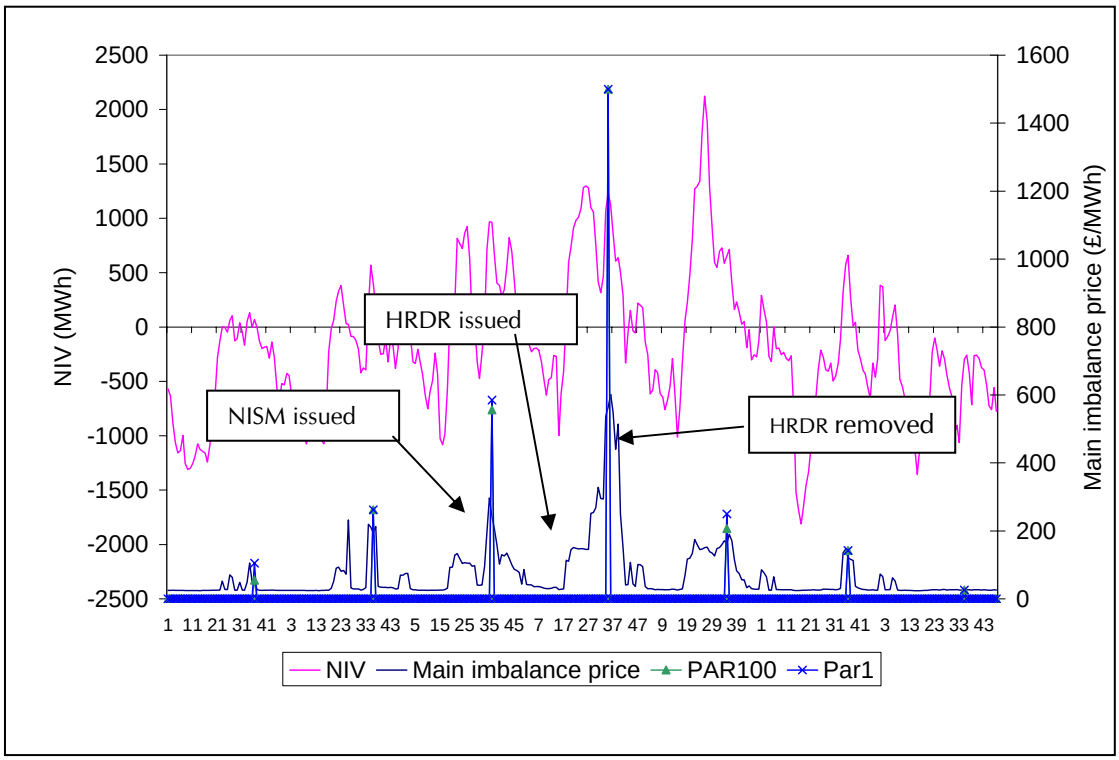
Figure 26: Change of main imbalance price compared to NIV - 26 December 2005 – 1 January 2006

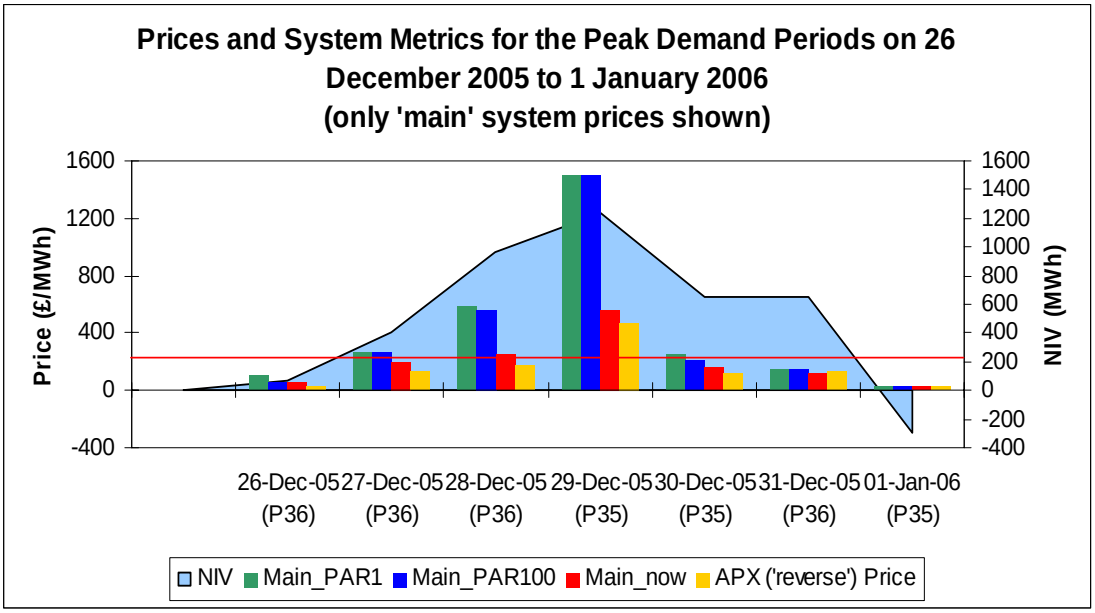


Source: NGET data for PAR100, PAR1. Ofgem data for NIV and main imbalance price

4.3. Figure 27 below shows a comparison of the main imbalance price that applied to the period and NGET's calculations as to what the main imbalance price would have been under both a pure marginal and a modification proposal P194 (PAR100) calculation, concentrating on the peaks periods of interest.[59]

[59] The data was provided by NGET with some caveats as it would have to undertake a further 'run' of this data before confirming the cash out prices. Any differences are not likely to affect the overall results of this analysis.

Figure 27: Price signals over peak periods - 26 December 2005 – 1 January 2006



Source: NGET

4.4. Figure 27 shows that a marginal or PAR100 derivation would have resulted in much sharper price signals for the evening peaks on 28 and 29 December 2005 than was the case based on the actual cash out prices (shown in the red bars). The red line shows the average of the actual cash out prices shown in the figure.

Position in the gas market – 29 December

4.5. In the gas market, the post Christmas period saw the highest demand seen this winter of around 390 mcm, due to temperatures nearly 4°C below the seasonal norm. There were flows from the Isle of Grain LNG import terminal and imports from Continental Europe via the IUK interconnector, but demand was mainly met by beach and storage deliveries.

4.6. Within-day, National Grid Gas (NGG) estimates of projected closing linepack fell to around 290 mcm from 307 mcm at the start of the day.[60] There were

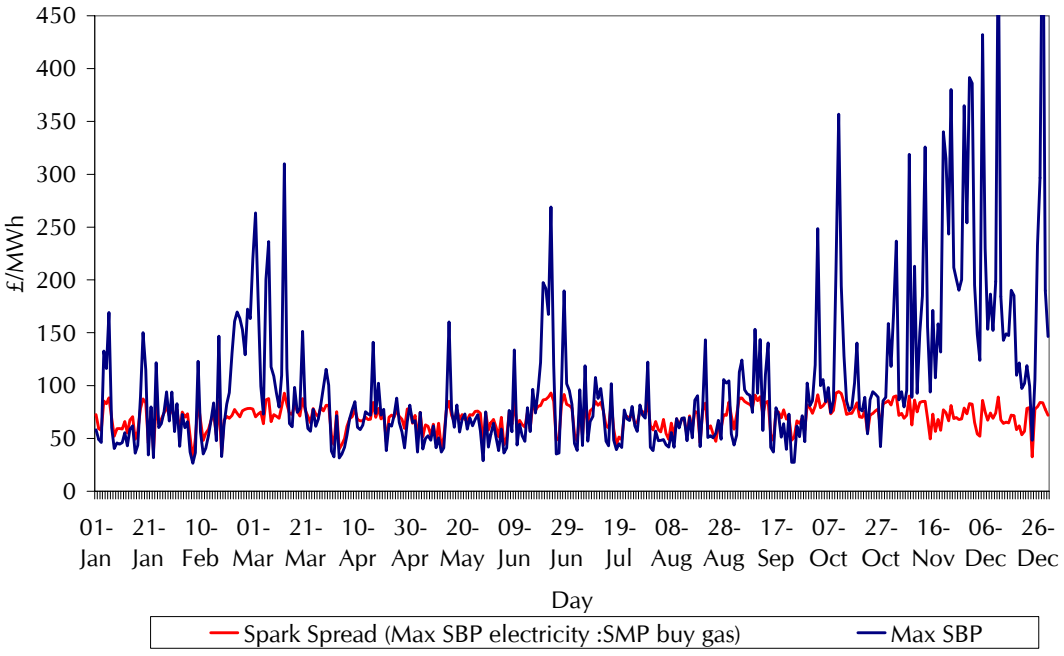
[60] Throughout the day, NGG produces estimates of closing linepack for that day known as Predicted Closing Linepack (PCLP). This forecast of closing linepack is based on detailed data NGG receives from the offshore production and nomination data. A fall in PCLP could indicate supply outages or unexpected BSC modification proposal P194 'Revised Calculation of the Main Energy Imbalance Price', Impact Assessment

rumours of some minor offshore outages as well as higher than expected demand. NGG the SO for the main gas transportation system took 1.3 mcm of balancing actions in the gas market to resolve potential system shortages. In the event this action prompted the desired response and linepack finished the day above its opening value.

Gas and electricity market interactions

4.7. In order to understand the interactions between gas and electricity markets, Figure 28 shows the relative cash out prices that applied in the electricity and gas markets over 2005 (as measured by the cash out 'spark spread' [61] between the maximum daily SBP and the gas SMP buy price[62]) and the maximum daily SBP

Figure 28: Gas and electricity cash out prices



increases in demand relative to forecast. NGG is incentivised to maintain total linepack on the system at the end of each gas day close to the starting level through the linepack balancing incentive.

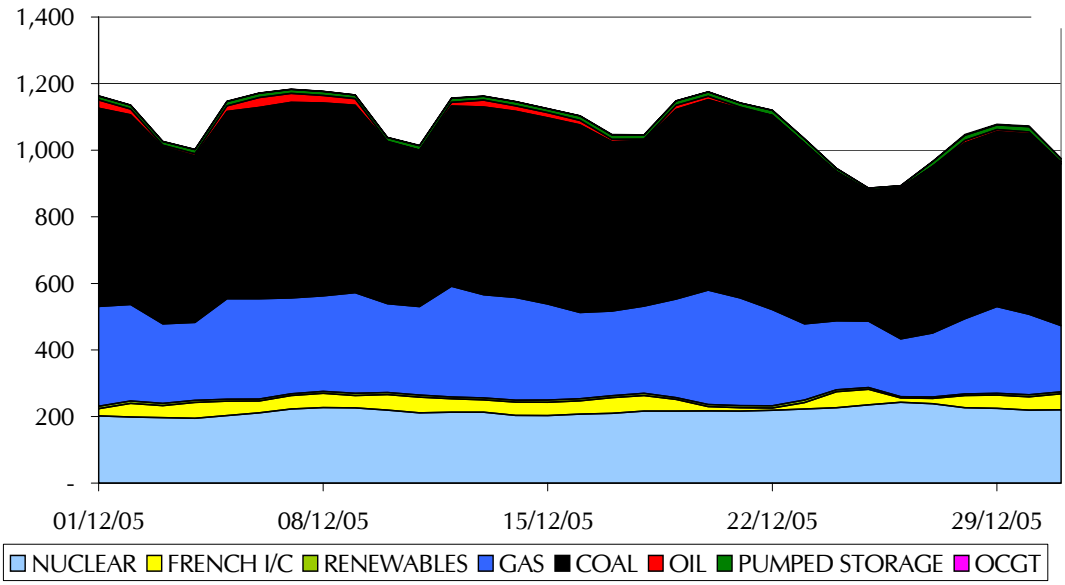
[61] The spark spread calculates for a given gas price in p/therm an equivalent £/MWh price in electricity. For this purpose, Ofgem has assumed an efficiency factor of 53% to calculate how much electricity would be generated from a therm of gas.

[62] SMP buy is the relevant cash out price in gas and is determined by the highest priced balancing action taken by NGG (or by a market reference price where NGG does not take any balancing actions that day). BSC modification proposal P194 'Revised Calculation of the Main Energy Imbalance Price', Impact Assessment

4.8. On the whole, the cash out spark spread has remained fairly constant, which suggests that there are interactions between the markets. What this chart does not show is the effect of within day gas prices on electricity cash out prices. For example, on 29 December 2005 within day gas prices rose sharply from around 80 p/th to around 150 p/th. The key question is what impact the increase in gas prices had on the activity within electricity market, given that there was high demand and system shortages on both the electricity and gas systems at the same time.

4.9. To help inform this point, Figure 29 shows the contribution of different forms of generation to electricity supply (including NGET's margin requirements) during December.

Figure 29: Electricity supply build up in November – December 2005

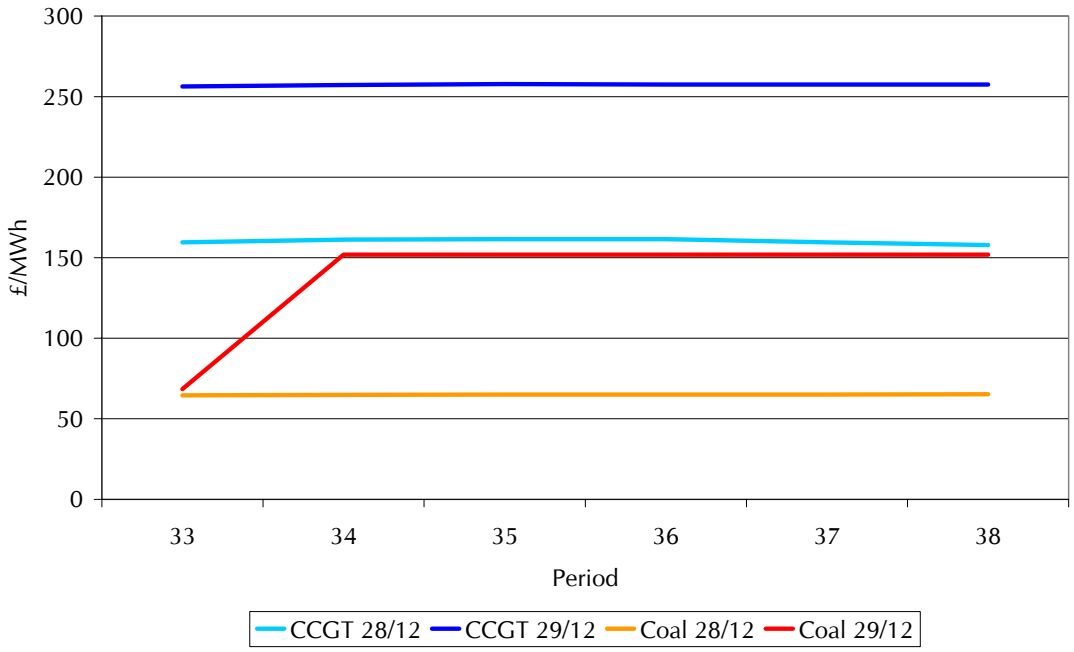


Source: NGET

4.10. In response to the events on 28-29 December 2005 there was a relatively muted increase in output by the gas-fired generation (compared to its potential to respond). This could be explained by the higher gas prices in that market meaning that available coal generation was more economic.

4.11. Figure 30 shows the pricing behaviour of coal and CCGT plant over the evening peaks of 28 – 29 December 2005. This figure shows the average of all offers[63] posted in the BM over these periods, including those trades that were not accepted.

Figure 30: Pricing behaviour of coal and CCGT's



4.12. Figure 30 shows that, on average, there was some response by CCGTs and coal-fired plant between days. On 28 December 2005, average offers posted by coal plant were just over £50/MWh and rose to £150/MWh on 29 December 2005. A similar magnitude of increase in offers was seen by CCGTs. However, there was essentially no repricing within day by CCGTs although there was some repricing by coal-fired plants on 29 December 2005. Consequently, the average price posted remained someway below the 'marginal' cash out price implied in the analysis above.

4.13. The above analysis suggests that the opportunity to offer in much higher prices and be accepted by NGET may not have been clear to CCGTs, as the average

[63] This excludes any bids over £9999 MWh, as these bids are generally referred to a "sleeper bids" and BMUs typically post such bids on the expectation that they will not be accepted.
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cash out price was providing relatively weak signals even though an HRDR had been issued.