Mr Roger Witcomb
Chair, CMA energy market investigation panel

13 February 2015

Dear Roger

Reflections on cash-out arrangements

At the hearing on 11 December 2014 I was asked about cash-out arrangements. Having now refreshed my memory of the issues, and checked on the present status of the debate, I offer the following reflections that might be of assistance to the panel.

To put my comments in context, when I was DGES at OFFER, I proposed in July 1998 to move from the Pool to what were then known as Revised Electricity Trading Arrangements (RETA). These arrangements, later known as New Electricity Trading Arrangements (NETA), were finalised and implemented by my successor at Ofgem, including with respect to cash-out arrangements. Since 2006 I have made a few contributions to discussions on cash-out arrangements, including a 2007 Report for Ofgem that included proposing a balancing market.[1] Ofgem cited that Report in its 2011 *Issues Paper*.[2]

I have not been involved in recent discussions on cash-out arrangements, and am not familiar with the more technical and operational issues. Hence, my present comments are related to general principles rather than to details of implementation.

In summary, I suggest

1) that the present dual cash-out price arrangement was designed to address concerns that obtained at the time of NETA's original implementation, that those concerns no longer obtain now, that the dual cash-out arrangement has an adverse effect on competition, and its replacement by a single cash-out price is long overdue;
2) that there is a case for some move towards sharper prices, such as might be embodied in a move from PAR 500 to PAR 250 or PAR 100, but that it would be premature to move immediately to PAR 1;
3) that there would be advantage in better reflecting the costs of reserve (STOR) in periods when capacity is tighter;
4) that the case for including demand control actions in the cash-out price is not as strong; and

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[1] Imbalance prices, tolerance bands and quantity premium bands, *Insight 1,* Cornwall Consulting *Energy Spectrum*, Issue 48, 4 September 2006, 17-18.
http://www.cornwallenergy.com/cms/data/files/Downloads/StephenLittlechild2006.pdf
Electricity cash out arrangements, a Review carried out for Ofgem, 9 March 2007, at
http://www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/CashoutRev/Documents1/19091_cashoutreviewSLittlechild.pdf
A proposal for a balancing market to determine cash out prices, *Insight 3,* Cornwall Consulting, 17 April 2007.
http://www.cornwallenergy.com/cms/data/files/Downloads/littlechildbalancingmarket.pdf
Response to Ofgem's consultation on electricity cash-out issues, 23 January 2012, also available at http://www.eprg.group.cam.ac.uk/research/other-papers/other-papers-2012/
[2] *Electricity cash-out issues paper*, Ref 143/11, Ofgem, 1 Nov 2011, para 3.20 fn 23.

5) that there would be advantage in having a balancing market as opposed to a balancing mechanism; that in this respect GB arrangements are now looking rather dated compared to some other markets; and that the CMA might wish to consider whether the absence of a balancing market has had an adverse effect on competition in the GB market, and whether more urgent steps to introduce a balancing market would remedy that adverse effect.

Stephen Littlechild

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Reflections on cash-out arrangements

1. CMA Issues statement

1. The CMA Issues Statement did not mention cash-out arrangements specifically, but had this to say about balancing issues and market rules.

> 29. … The current electricity trading rules were designed with strong incentives on generators and retailers to balance their own supply and demand portfolios, by making energy imbalances particularly expensive. Firms have responded to these incentives either through bilateral contracting or vertical integration (or both). …
>
> 31. **High transactions costs**. In order to avoid the risk of imbalance, independent retailers and generators need actively to be engaged in bilateral contracting up to 1 hour before delivery. This is costly. Moreover, independent generators and retailers have fewer options available for balancing than do the vertically integrated incumbents. The market rules may therefore increase costs to non-vertically integrated entrants and ultimately reduce competition in retail markets and raise prices to customers.

2. The two paragraphs need to be read together. Certainly bilateral contracting is costly, and it is possible that independent generators and retailers have fewer options for balancing. But neither of these is a reason per se for supposing that market rules increase costs to independent parties, reduce competition and raise prices to customers.
3. If the market rules reflect costs and facilitate trading in order to reduce costs and risks, and if such parties still have higher costs, it means that vertical integration is a more efficient way of producing and supplying electricity. Competition is not thereby reduced but simply takes place between vertically integrated companies, and prices are not higher as a result. Indeed, changing the market rules to specially favour independent generators and retailers would increase costs in the system as a whole, distort competition and raise prices to customers.
4. However, if the market rules do not reflect costs and facilitate trading – if they reflect an undue incentive on generators and retailers to balance their own supply and demand portfolios, and if energy imbalances are "particularly" expensive in the sense of the charge for accommodating them being more than the underlying cost – then they could indeed be increasing costs, distorting competition and raising prices to customers.
5. The important question is therefore whether the present market rules do indeed reasonably reflect costs and whether they facilitate trading to reduce costs and risks, or whether the present rules fail to reflect costs and facilitate trading. In answering this question it is important to look at total costs as well as costs at the margin.

2. Presently proposed reform to cash-out arrangements

6. Ofgem takes the view that, in certain respects, the present market rules fail to reasonably reflect costs and facilitate trading, and therefore need to be revised. Following its Electricity Balancing Significant Code Review (EBSCR), Ofgem in May 2014 proposed four major reforms to the arrangements for cash-out:

- move to a single cash-out price for each settlement period
- make cash-out prices marginal
- improve the way reserve costs are incorporated in cash-out prices
- include a cost for demand control actions (disconnections and voltage reductions) in cash-out prices.

7. I comment in turn on these four proposals. They address the cost-reflectivity of the rules, but they do not focus on facilitating trading. I therefore comment also on an avenue of reform that was temporarily shelved in May 2014, namely the possible move to a balancing market.

3. Single cash-out price

8. In July 1998 OFFER's proposal for the new trading arrangements envisaged a Balancing Market for each trading period, with imbalance prices based on the average cost to the System Operator (SO) of the trades that it needed to carry out in the Balancing Market.[3] The implication was that there would be a single imbalance price in each period.[4] In July 1999 Ofgem proposed (and subsequently implemented) the New Electricity Trading Arrangements (NETA) with a Balancing Mechanism with a dual cash-out price. It explained

> "The use of a dual cashout price regime will incentivise participants to balance their own positions by Gate Closure and hence the actions that the SO has to take should be minimised. Thus, the cash-out prices should also assist in fulfilling the RETA objective of minimising the role of centrally administered mechanisms and facilitating bilateral trading of electricity."[5]

9. Ofgem continued to take this view for many years. In its *Cash-out Issues Paper* November 2011 it proposed four principles by which to assess possible arrangements.[6] The first proposed principle said

> "Cash out arrangements should, as far as possible, allow and provide incentives for market participants to balance their positions without the need for unilateral actions to be taken by the System Operator." (para 3.1 p 34)

[3] *Review of Electricity Trading Arrangements: Proposals*, OFFER, July 1998, paras 4.52, 4.81, 5.40.
[4] OFFER's interim conclusions a month earlier had mentioned that some other systems used two separate imbalance charges, one for those parties that were short and another for those that were long. *Review of Electricity Trading Arrangements: Interim Conclusions*, OFFER, June 1998, paras 5.39, 5.40. The *Proposals* document in July made no further mention of this. The *Framework* document in November said that "The precise nature of these imbalance prices is yet to be decided. The intention is to provide stronger incentives than at present for generators and suppliers to meet their commitments." *Review of Electricity Trading Arrangements: Framework Document*, OFFER, November 1998, para 2.3, p 11.
[5] *The new electricity trading arrangements, Volume 1*, Ofgem, July 1999, p 52.
[6] Ofgem, *Electricity cash-out Issues Paper*, Reference 143/11, 1 November 2011.

10. Responding to this consultation in January 2012, I reviewed the reasons originally given for the dual cash-out price. [7] I noted that there was no "RETA objective of minimising the role of centrally administered mechanisms". This might have referred back to the actual and potential problems associated with the capacity mechanism in the previous Pool. A non-Pool approach was uncharted territory in 1999 – in effect, we were moving from a system where the SO told the generators what to do, to a system where the generators told the SO what they wanted to do. It was considered important that the incentives to self balance "should serve to limit the scope of the short-term actions that the SO has to take, and thereby make such actions more manageable within short timescales". (Ofgem, July 1999 p 213)
11. However, I argued that a different approach was appropriate once the market had developed. I concluded "Whatever the merits of a dual cash-out mechanism in facilitating the introduction of NETA, the economic and practical case for it is no longer compelling. It may well have provided an artificial incentive to vertical integration, favouring incumbent competitors over entrants, and hindering the development of more liquid traded markets."
12. Others presumably made similar points. In April 2012 Ofgem basically accepted the argument.[8] From its initial consultation in August 2012[9] through to its final policy decision in May 2014[10], it proposed three high-level objectives, one being to "increase the efficiency of energy balancing". There was no more reference to providing an incentive to self-balance rather than use the balancing mechanism.
13. The most efficient outcome is for market participants to use self-balancing (whether by vertical integration or bilateral contracting) and the balancing mechanism in whatever combination is lowest cost. Policy should also seek to facilitate and lower the cost of bilateral contracting and of using the balancing mechanism.
14. The dual cash-out mechanism is inconsistent with these principles. I believe that the arguments against the dual cash-out price, and in favour of a single cash-out price, remain valid today. Given that Ofgem and reportedly most market participants take this view, there is no need to set out the arguments in more detail. I therefore support Ofgem's present proposal to replace the dual cash-out price by a single cash-out price. The CMA investigation might well conclude that the dual cash-out price has an adverse effect on competition (AEC), and that Ofgem's proposal to replace it by a single cash-out price would remedy that AEC.

[7] "Response to Ofgem's consultation on electricity cash-out issues", 23 January 2012. This drew on my earlier review "Electricity Cashout Arrangements, a review carried out for Ofgem", 9 March 2007.

[8] It changed the wording of the first proposed principle from "as far as possible" to "as far as efficient", and commented "The SCR [Significant Code Review] should not be restricted by the idea that self-balancing is always more efficient than SO balancing." Ofgem, *Electricity Cash-out Significant Code Review, Stakeholder Event on Scope – Scope and Principles*, 30 April 2012, at slide 4, Proposal to amend Principle 1.

[9] Ofgem, *Electricity Balancing Significant Code Review - Initial Consultation*, Ref 108/12, August 2012.

[10] Ofgem, *Electricity Balancing Significant Code Review- Final Policy Decision*, 15 May 2014

4. More marginal main cash-out price

15. Originally, under NETA, cash-out prices were calculated as an average of all actions taken by the SO to balance. This was subsequently reduced to the most expensive 500MWh of actions under BSC Modification P205.[11] Presently, this most expensive 500 MWh of actions is calculated after removing any system balancing actions by "flagging and tagging" [12], and having offset any actions in the reverse direction against the most expensive actions in the main direction.
16. Ofgem's concern is that the cash-out price thus calculated is inefficient because it is too low: it is an average cost of balancing which is less than the marginal cost of balancing.

> We have consistently raised concerns regarding the calculation of the cash-out price based on an average of the cost of actions taken by the SO, most notably in Project Discovery. We are concerned that this averaging dampens the cash-out price as a signal of scarcity in the market – in particular at times of system stress – and contributes to *missing money* in forward markets especially for providers of flexibility. This in turn has detrimental impacts for security of supply and the overall costs of balancing.
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> Calculating cash-out prices based on a weighted average reduces the cash-out price below the SO's marginal cost of balancing. As such, the additional unit cost of imbalance to market participants (the cash-out price) is below the additional unit cost of balancing energy to the SO. This is inefficient as it could reduce parties' incentives to balance.[13]

17. Ofgem's proposal is to change the calculation of cash-out price from PAR 500 to PAR 250 then to PAR 50 and ultimately to PAR 1. That is, to base the calculation of cash-out price on the highest-price 1 MWh of actions taken by the SO instead of the highest price 500 MWh of actions (after flagging, tagging and offsetting). Ofgem argues that this will make prices "more marginal" and that PAR 1 would be a "fully marginal" price. A price below marginal cost is inefficient "as it could reduce parties' incentive to balance". (fn 28, p 13)

5. The concept of marginal cost with respect to energy balancing

18. I have some reservations about the use of the term marginal in this context, and the assumption that a more marginal price is necessarily more efficient. This is not to say that a move from PAR 500 is inappropriate, but rather that it has to be justified on more pragmatic grounds. I take these points in turn.
19. The concept of marginal cost assumes the ranking of actions taken at a single point in time. This is generally not the case here. As expectations and opportunities constantly evolve, the SO typically engages in the market at many different times before and during the half-hour period in question, might

[11] Ofgem, *Electricity Balancing Significant Code Review- Final Policy Decision*, 15 May 2014

[12] Continuous Acceptance Duration Limit (CADL) Flagging removes short-term duration actions (less than 15 minutes). De Minimis Tagging removes actions less than 1 MWh.

[13] Ofgem, *Electricity Balancing Significant Code Review – Final Policy Decision*, May 2014, p 13

well both buy and sell with respect to that period, and some trades may spread across several periods. As one familiar with the process puts it,

> In the balancing mechanism near real-time, the system operator does not see a nice stack of energy trades but rather chooses from a plethora of up and down actions each with different dynamic characteristics in the presence of noisy need. Some might be attractive enough to keep for several trading periods. Others will need to be reversed in favour of new opportunities or will come to an end because of self-dispatched movements.

20. In such a context, the concept of marginal cost is a tenuous one. If one were looking for some sort of "representative" figure, the presently defined PAR 500 calculation is not a bad one. The most expensive 1 MWh bought or sold (even after flagging, tagging and offsetting) is not necessarily representative of the cost of a slight increase or reduction in capacity with respect to the half-hour as a whole. Having said that, in normal circumstances the difference between these two definitions might not be great.
21. On the other hand, in exceptional circumstances the conditions for defining marginal cost more nearly seem to obtain.

> Punctuating the routine running are events such as an unexpected loss of plant or step up in demand as the system is already getting tight. The system operator may then need to make some big purchases as well as alert the market to reduced margins and the potential need for demand control.
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> The larger volume of buys in these tightening conditions may see significantly higher prices 'up the supply curve'. Under such conditions, there might be coincident buys with lower (intra-marginal) prices before the last one which, hopefully, achieves balance.

22. How often might such exceptional circumstances obtain? I understand that National Grid defines system stress as when "the actions which are taken by the system operator to manage the underlying energy balance are of a large magnitude and are expensive". A large magnitude of actions is taken to be greater than 1000 MWh and expensive is taken to be System Buy Price (SBP) greater than £150/MWh. In 2012 and 2013 this combination obtained in 17 half-hour settlement periods (0.05% of all settlement periods) over the course of 6 different days (4 in 2012 and 2 in 2013). The number of successive settlement periods affected per instance varied from 1 to 6.
23. In such exceptional circumstances, when decisions are taken to take actions in order of cost, it seems as though marginal cost is a more relevant concept. And marginal cost could be quite different from average cost. That is PAR 1 could be significantly higher than PAR 500. Thus, regardless of the term used, the question whether to use PAR 500 or PAR 1 or something in between is a very pertinent one.

6. Marginal cost pricing versus average cost pricing

24. As explained above, Ofgem argues that a marginal price is more efficient than an average price.

> 3.6. Using the marginal (most expensive) action to set the cash-out price sends the most efficient signal to the market. It most accurately reflects the SO's cost of balancing the system at the margin and provides the signal to market participants to exhaust all opportunities to achieve an extra unit of balance where the cost of doing so is less than that of the SO. (Ofgem May 2014)

25. This is a valid and important consideration. Particularly in the exceptional conditions discussed, the system operator might have to buy power that is much more expensive than usual. It is therefore important to encourage market parties to explore and seize opportunities that are cheaper than the system operator's highest-price buy to help alleviate the situation. Moreover, if cash-out price were below that highest level, it could incentivise generators to reduce delivery on existing contracts, with a view to selling to the SO at the marginal price and paying the lower average cash-out price.
26. But that does not necessarily mean that a "fully marginal" price is the most efficient solution. A classic article by Coase argues that other considerations are relevant too. [14]

> Coase examined the case for marginal cost pricing in industries characterised by decreasing costs, such as railroads. He acknowledged the case for marginal cost pricing, which would enable consumers to buy more of a product if they valued it above the additional cost of producing it. But since marginal cost was below average cost, this would not bring in sufficient revenue to cover the firm's total costs. The proponents of marginal cost pricing proposed that government should provide a subsidy to make up the difference. Coase argued that this policy as a whole had several weaknesses:
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> - government would have to decide which products should be provided and which firms subsidised, this would be inefficient because there would be little information about whether customers were actually prepared to pay for the total cost of supply, and no subsequent market test as to whether these estimates were correct;
> - there would be vulnerability to political factors influencing government decisions, and greater government involvement in the running of the industry, which not be conducive to efficiency;
> - there would be a redistribution of income in favour of consumers of goods produced in conditions of decreasing cost;
> - the consequent increase in taxation would raise the prices of other goods and services above marginal cost, and/or increase taxes on income, both of which would have distorting and disincentive effects.
>
> It was not obvious that there were net gains from this policy of marginal cost pricing plus subsidy, compared to average cost pricing or (which was Coase's preference) some form of price discrimination to increase output while covering total cost. He called the proposal for marginal cost pricing "a recipe for waste on a grand scale".

27. It is not argued that electricity balancing is produced under conditions of decreasing cost – indeed, perhaps the opposite. Nor that a move to more marginal (sharper) prices would necessarily be undesirable – indeed, there is merit in it, especially in the aforementioned exceptional conditions. However, any proposal, and indeed the present arrangements, need to be assessed in

[14] R H Coase, "The marginal cost controversy", *Economica*, N.S. 13, August 1946.

terms of the whole context, and all the impacts, not just on whether price equals cost at the margin.

7. Recovering the System Operator's Costs

28. Discussion of how a cash-out price should be calculated therefore needs to be set in the context of the means of recovering the System Operator's costs as a whole. At present this is a rather unusual and obscure process. The total costs of the System Operator's activities – about £1 billion in 2013-14 - are charged to transmission users via Balancing Service Use of System (BSUoS) charges. A subset of those costs associated with energy balancing is identified, cash-out prices are determined using the PAR 500 methodology, and these are paid or received by those market participants that are out of balance. Whatever net revenue is derived from this process is returned to market participants via the Residual Cashflow Reallocation Cashflow (RCRC), tellingly known as the Beer Fund.
29. In other words, the cost of energy balancing is charged to market participants twice: once as part of the BSUoS charges and again in the form of cash-out charges. And then a third set of charges, or rebates, refunds the net amount raised by the second set. Ofgem has observed that "reconciliation cashflows are large and opaque".[15]
30. Ofgem's *Final Policy Decision* provides some modelling of the impact of future possible changes in PAR levels and single cash-out prices on the situations of different types of market participants. But there is little on how the present situation operates as a whole, and what impacts it might be having on the decisions of market participants and hence on costs to customers.
31. All three sets of charges or refunds (BSUoS, cash-out and RCRC) impact on various important decisions of market participants – for example, whether to enter or leave the market, what types of capacity to build or purchase, whether to vertically integrate or trade bilaterally or operate exposed to cash-out charges. The form of charging redistributes income between different kinds of market participants, presumably not in an intended way, and thereby influences these decisions.
32. Almost the entire focus of the present policy discussion is on whether cash-out charges reflect costs at the margin. As noted, this is important, and Ofgem has also analysed how changes in the manner in which energy balancing costs are charged out might be expected to influence the levels of these charges and hence decisions about balancing and trading and investment in capacity etc. But there seems to be no similar analysis of the effects of presently double-charging this same cost on the decisions of market participants. Nor much discussion of whether proposed changes to cash-out rules would under-recover or over-recover energy balancing costs in total.
33. The BSUoS charges are constrained to recover the actual total costs of the System Operator. This anchors the level of those charges. In contrast, cash-out charges are regarded as a signal; they are related to actual energy balancing costs in a much more elastic way. A consequence of this is that the level and severity of cash-out charges is more vulnerable to political and commercial pressures. At times when security of supply is a greater concern, there is likely

[15] Ofgem, *Cash-Out Issues Paper*, paras 2.25,6

to be pressure to increase the sharpness of charges; at times when cost to consumers is a greater concern, there is likely to be pressure to reduce the sharpness. Similarly, there may be commercial pressures to favour certain types of company or types of generation. These are not irrelevant considerations, but recovering total costs and no more provides some protection against undue influence.

34. In the present case, I accept the case for sharper cash-out charges to better reflect costs at the margin, particularly in exceptional circumstances when the SO is under pressure. But discussion of the merits of particular changes – whether PAR 250 or PAR 1 - could usefully be accompanied by a consideration of how the resulting revenues would relate to the System Operator's energy balancing costs in total. In addition, some discussion of the advantages and disadvantages of double charging for energy balancing costs, and the feasibility of changing this, would seem appropriate.
35. Two further considerations seem relevant. First, a cash-out price based on a smaller number of trades may raise some concern about market manipulation or coordinated action. Ofgem has calculated that the average number of trades determining cash-out prices would reduce from 15.5 with PAR 500 to 3.6 with PAR 1, and the frequency with which price would be based on just one trade would increase from 3% to 22%.[16] This might indeed be difficult to manipulate, as Ofgem suggests, but popular perceptions of manipulation might not appreciate this.
36. Second, it is not yet clear how market participants will respond to sharper price signals and what impact the move to a single cash-out price will have, for example on new and smaller suppliers who may need a little more time to adjust to sharper price signals.
37. For these reasons, my inclination would be to move towards a sharper price signal – say to PAR 250 or perhaps PAR 100 but not immediately to PAR 1 - taking into account the change to a single cash-out price, the implications for total cost recovery and the overall effects on competition and market participants. This would not preclude a further and later sharpening of the cash-out price if experience suggested that this would on balance be desirable.

8. Improved incorporation of reserve costs

38. At present, the utilisation payments associated with Short Term Operating Reserve (STOR) are incorporated into the cash-out price but the availability payments (option fees paid up front to make the option available) are recovered separately via a Buy Price Adjuster (BPA) which is added to the System Buy Price based on usage of such reserves in the previous year. This is only weakly related to the need for such reserves in the current year. "As a result, the cash-out price is dampened during times of system stress and arbitrarily increased during times when STOR is not required." (*Final Policy Decision* para 3.46) Ofgem therefore proposes to allocate the costs of STOR according to its value to the system in each period, using a Reserve Scarcity Pricing (RSP) function based on a LOLP-VoLL calculation.
39. It seems to me that the argument for allocating the costs of reserve to those periods that are most likely to need them is a sound one. Whether the precise

[16] *Draft Policy Decision Impact Assessment*, Table 12, p 34.

RSP methodology is the best way to do this is something I cannot comment on. However, the case has been put forward in the US by Professor W W Hogan, whom I have known for many years and whose work and advice are greatly respected. I understand that similar adjustments have been successfully implemented in numerous US jurisdictions.

40. Ofgem reports that "Some stakeholders have raised concerns about de-linking the price of STOR in cash-out from actual STOR costs." (*Final Policy Decision* para 3.60) This is the kind of concern that I expressed above, and seems to me valid. Fortunately, Ofgem has taken it seriously. "As such, we have carried out quantitative analysis of historic data to test the potential impact of the RSP. This shows that historically the RSP function approach allows for a closer reflection of total (long-run) STOR costs in cash-out than existing arrangements." (*Ibid*, para 3.60)
41. Ofgem's investigation shows total STOR availability fee costs of about £70m in 2011/12, compared to BPA cost of about £20m. Ofgem calculates that an RSP price "resulted in an increase in imbalance charges of approximately £40m in 2011/12 [ie to about £60m], which is in fact a closer reflection of STOR availability costs [about £70m] than achieved by BPA". It concludes "our historical quantitative analysis supports our qualitative analysis by suggesting that the RSP would lead to much improved price signals each settlement period which would not be at the detriment of overall cost – reflectivity". (*Final Impact Assessment,* Appendix 3, Fig 10 and para 1.11)
42. This is the kind of calculation that seems to me relevant, with one qualification. Since STOR options can be exercised for other purposes such as system balancing as well as for energy balancing, it would seem that the BPA cost should be properly compared with that proportion of total STOR availability costs that are used for energy balancing purposes. I understand that in practice most STOR options are probably used for energy balancing. But suppose for illustrative purposes that only about two-thirds of the STOR availability costs, say £45m, were associated with energy balancing. If the RSP approach recovered charges of about £60m rather than about £20m, such charges would over-recover energy balancing STOR costs by about £15m rather than under-recover them by about £15m. On that basis, RSP prices could not be said to be "a closer reflection of STOR availability costs".
43. Clearly this is a matter for others to examine, with evidence on the actual or plausible numbers. My conclusion is, first, that there is a strong case for relating STOR availability costs to the periods in which they are most likely to be used; and second, that the method for doing this should seek to ensure that the total additional revenue from doing so is approximately equal to the relevant total costs incurred for energy balancing purposes. Having said this, the difficulties and approximations in identifying and allocating these costs – and in tagging and flagging to determine cash-out prices generally - suggest that some alternative approach might well be preferable. I turn to that shortly.

9. Including a cost for demand control actions in cash-out prices

44. Ofgem explains that under the present balancing arrangements, prices do not properly reflect scarcity, particularly when the system is tight. "Costs of involuntary demand disconnections (blackouts) and voltage reduction actions (brownouts) are not included in cash-out prices at all. These are a cost to

consumers that the SO and market participants do not face." (*Final Policy Decision*, para 1.3) Ofgem proposes that "An administrative cost will be included in the cash-out price for volumes of SO-instructed disconnection and voltage reduction (or 'SO-instructed Demand Control actions'). This will be £3,000/MWh upon introduction with the core EBSCR reform package, by early winter 2015/16, and will rise to £6,000/MWh by early winter 2018/19." (para 2.1)

45. Ofgem originally envisaged that customers would be compensated by the SO for such blackouts and brownouts. On that basis I believe there would have been a sound basis for reflecting these disconnection costs to customers in cash-out charges.
46. However, after consultation, Ofgem decided that customers should not be compensated.[17] This was because the policy would be a transitory measure rather than have enduring effects (particularly because of the rollout of smart meters), and because the costs of implementation would be disproportionate.
47. In consequence, these costs of disconnection would not be part of the costs incurred by the SO, or indeed by suppliers. Whether or how closely they would reflect the actual costs imposed on customers is necessarily a conjecture. Sending a signal in this way, with a view to increasing security of supply by means of a higher, sharper and more volatile cash-out price, would transfer income from customers to certain kinds of generators. The decision as to the magnitude of this transfer is therefore particularly vulnerable to the political and commercial pressures mentioned earlier.
48. A cost that is sufficiently high to reward generators, but not sufficiently high to be worth compensating customers, for a measure that is envisaged to be only transitory, does not sound entirely convincing. The case for this particular proposal does not seem as strong as for Ofgem's other three proposals.

10. EMR Capacity Market

49. This note has not explored the implications of the EMR Capacity Market. These obviously need to be considered. But as Ofgem has indicated, reform of the cash-out mechanism is needed regardless of the nature or existence of the ERM Capacity Market.

11. Balancing mechanism or balancing market

50. In its 2011 *Issues Paper* (ch 3 and Appendix 4), Ofgem proposed to explore the concept of a balancing market instead of a balancing mechanism. It said

> A balancing market may provide the opportunity for greater transparency in the setting of cash-out prices and provide smaller participants with greater opportunities to balance their positions without needing to pay potentially large premia to larger players to manage their imbalance risk. (para 3.21)

Appendix 4 described how a combined balancing and reserve market could help address seven issues identified with the current cash-out arrangements.

[17] *Final Policy Decision* paras 3.33 – 3.38.

51. In February 2013 Ofgem decided to focus the Electricity Balancing SCR on the four shorter-term issues discussed above, and to explore a balancing market as part of a longer-term work programme. [18]
52. In my view, a balancing market could overcome some of the limitations of the present mechanism, increase the extent of competitive markets, and offer more attractive possibilities for market participants. I set out a case for a balancing market in my earlier papers referenced above. Clearly there are many options, another being an electricity balancing market modelled on the present gas market.
53. Others are better able to analyse the possible options here and assess their pros and cons. My sense is that GB arrangements, in many ways at the forefront 15 years ago, are now looking dated and somewhat cumbersome. In more modern markets such as Texas, prices are being set for each 5 minute period rather than for each half-hour. Balancing markets play a much more active role than in GB, without compromising the System Operator's ability to carry out its functions. Parties can trade up to, during and even beyond each balancing period – something for which National Grid has indicated sympathy in its evidence to the current CMA investigation.[19]
54. With respect to balancing, competition seems more active in these other markets. The CMA might wish to consider whether the absence of a balancing market has had an adverse effect on competition in the GB market, and whether more urgent steps to introduce one would remedy that adverse effect.

[18] *Update on the Electricity Balancing Significant Code Review (EBSCR) and request for comments on proposed new process to review future trading arrangements,* Ofgem letter, 18 February 2013

[19] Among " areas that could be explored further to assess the potential for improvements", National Grid suggests "Permitting the notification of bilateral market trades to central settlement closer to or sometime after real-time delivery. This would allow wind generators greater opportunity to trade out short-term imbalance and provide the market with more opportunity to innovate and develop short-term flexibility. " National Grid initial submission, 21 January 2015, in answer to the question "Would it be more efficient/less costly for National Grid to manage all dispatching? Please indicate the likely scale of any efficiencies/reduction in costs"