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Wednesday 22 October 2013

Dear Andreas,

Re: Consultation on Electricity Balancing Significant Code Review: Draft Policy Decision and Impact Assessment

Thank you for the opportunity to respond to the above consultation. E.ON agrees with Ofgem's objectives to ensure that GB electricity balancing arrangements complement policy initiatives such as DECC's Electricity Market Reform (EMR) Capacity Market (CM) and comply with European moves towards a single internal market for energy. We are concerned, however, that with simultaneous development of multiple initiatives, there is a risk that some elements, rather than complementing, may undermine or conflict with others. This prospect already seems to have arisen with the Value of Lost Load (VoLL) proposals in the gas SCR, CM and Electricity Balancing SCR. It also appears to us that some of the proposals put forward in the EBSCR are inconsistent with Ofgem's Secure and Promote goals to increase liquidity and competition. Disadvantaging intermittent generation that has limited ability to react to price spikes would also not support government targets for renewable generation and emission reductions.

In summary E.ON's views on the proposals are that:

- There is no particular reason to change from PAR 500MWh which gives parties a reasonable balance of imbalance risk/reward.
- PAR 1MWh would be excessively penal and risk system pollution.
- A VoLL of £3,000 or £6,000 would result in extreme unpredictable spikes in cash-out prices. This would not promote better balancing overall, but simply penalise companies unlucky enough to be out of balance in the relevant period.
- Ultimately, this could put some parties out of business, especially smaller generators and suppliers.

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- Provision of information to the market must be improved. For reserve costs and VoLL, the market needs visibility in order to foresee and respond to prices prior to gate closure.

- Overall the proposals would be incredibly costly for companies for very little if any benefit to the consumer.

- The analysis demonstrates that more benefit would come from a single price than anything else. This would be a straightforward change that could be implemented promptly.

- Decisions on more radical changes should be deferred from 2014 to 2015 when European Network Codes are finalised.

<u>Timing</u>

With the market facing an unprecedented volume and magnitude of changes we believe that further reforms in the timescales suggested by the EBSCR are undesirable. Above all the industry requires a stable regulatory environment. Additional change would add to risk and uncertainty for existing and potential market participants, raising the barrier to entry and costs to consumers. It could also mask the effects of individual measures and increase the risk of unintended consequences. With national and European developments affecting the energy market, time is needed to adapt to new frameworks, not repeated interventions that through increased regulatory risk and sometimes, in themselves, undermine liquidity and competition.

The Capacity Market is a major development and with challenging timescales to implement a CM in 2014, it is desirable to focus on establishing the CM and Contracts for Difference (CfD). Allowing these measures to be implemented before any significant reform of balancing arrangements would allow a more informed review once their impact could be assessed.

We appreciate that Ofgem has attempted to ensure that the proposed reforms are 'not in conflict with the direction' of the Target Model (TM). While European Network Codes are still being developed and we do not know whether the GB market will form one or more pricing zones under the TM, it would be wise to refrain from further changes until at least the Electricity Balancing Network Code (NC EB) and implementation timescales are finalised. To do otherwise would risk having to follow such a change, in a short space of time, with further modification(s). While National Grid appears to have been influential in the development of the Code through ENTSO-e and DECC will be representing GB views in Europe, we cannot be confident that changes will not be made in the final version which could make the SCR proposals non-compliant. The fact that such developments are likely to require some changes to GB arrangements emphasizes how unhelpful it would be to try and force any extraneous changes in the next few years.

We are concerned that Ofgem plan a final policy decision for early spring 2014 without further stakeholder interaction, when more work is required to determine the practical design of options such as the Reserve Scarcity Pricing function. We believe that an impact assessment of the final decision(s) will be necessary as part of the usual Code modification process; if a decision is made to go ahead with some proposals we believe that they should be developed through an industry Workgroup under normal Code governance. This could also allow for fine-tuning during the process should there be any clarification of European requirements in that time.

Further to these comments, our responses to the individual questions in the consultation are as follows:

Draft Policy Decision

Question 1: Do you agree with our proposal to make cash-out prices more marginal?

1. E.ON believes that the current PAR of 500 MWh, developed through a number of Balancing and Settlement Code (BSC) modifications which have in turn sharpened and dampened cash-out prices, has to date provided the right level of sharpness for the balance of the industry.

2. With the evolving generation mix, parties are already facing more volatile cash-out prices without a reduction in PAR.

3. We understand that Ofgem is trying to distinguish between incentivising capacity investment per se, which the CM is designed to do, and making that investment in *flexible* capacity. Nevertheless there is some overlap in these goals. Our view is that the CM is the correct vehicle to address the ‘missing money’ in the wholesale market and incentivise investment in capacity in order to maintain security of supply. Baringa’s CM sensitivity analysis also confirmed that it is the CM rather than cash-out reform that will drive capacity investments that should reduce Expected Energy Unserved (EEU). The CM will be far more important than cash-out prices for driving investment in new capacity, whether generation or demand-side response (DSR).

4. A more marginal cash-out would not support the CM in incentivising investment. Imbalance prices might feed through to the short-term market but the volatility of wind means that this would not be a consistent signal. As cash-out prices are not predictable, so not bankable, they are far more a risk than an opportunity, weakening not strengthening the case for investment. The potential for much sharper imbalance prices risks deterring investors, particularly in intermittent generation. This point was emphasized by parties at the 3rd EBSCR stakeholder session in 2012, and the bulk of respondents to the initial consultation, including some providers of flexible solutions. A more marginal price may be more rewarding for *reliable* generators, but forecasting errors or trips can be expected at any plant from time to time, regardless of fuel source.

Fossil plant might face fewer unplanned outages than intermittent, but very high costs for larger imbalances at times of system stress. Investment decisions on building or maintaining assets, flexible or not, would have to include the risk of such incidents coinciding with very high marginal prices.

5. While renewable/low carbon generation is supported with government subsidies, increasing potential balancing costs through a more volatile and penal cash-out price would lead to a higher level of subsidy being required to attract investment. Ultimately, the consumer would pay for higher CfD strike prices. This would not seem consistent with targets for renewable generation, carbon reductions and affordability for consumers.

6. Furthermore we are not convinced that more marginal cash-out prices would incentivise efficient balancing more than the current arrangements and PAR. Parties are already incentivised to balance and over time, the balancing market (BM) has become more efficient with a trend towards lower imbalance volumes and spreads (as demonstrated by the P217A review).

7. While balancing the system may become more challenging as the share of intermittent generation increases, it seems optimistic to suggest that more marginal pricing would assist this by incentivising self-balancing to a much greater degree than at present. Market participants may already have adapted their behaviour as much as possible. Wind generators, with limited ability to change their behaviour due to their intermittent fuel source, would be particularly vulnerable to more marginal pricing.

8. Embedded wind may not be exposed to imbalance risk directly; however they will not be immune to it, while transmission-connected wind generators limiting their exposure through a PPA are likely to see a detrimental impact in the level of discount they have to accept to agree this route to market.

9. While Ofgem hopes that investment in forecasting would be encouraged, we think this view is potentially unrealistic. Forecasting can never be perfect and parties have already invested significantly to improve forecasting to minimise imbalance exposures at PAR 500MWh. The prospect of a more marginal price, particularly a fully marginal PAR 1MWh, rather undermines the case for investing in forecasting systems. There is little point in spending a lot of money seeking minor improvements in accuracy if the benefits of improving forecasting in 99% of settlement periods could be negated by the 1% of periods when the company has the misfortune to be out of balance at the time of a sharp price spike. While we believe that we are a ‘stronger balancer’, this is what our own analysis of historic performance has demonstrated.

10. More marginal prices would increase Suppliers’ risk premium, pushing up their cost base: rising costs to balance would be paid by customers.

11. Baringa’s analysis also suggested that not only in 2020 but also in the tighter system modelled for 2030, *‘the variations in balancing cost associated with short-term balancing*

incentives are relatively modest associated with parties adopting different hedge positions', while a longer system by 2030 *'does not necessarily lead to cost savings'.*

12. Overall, there seems a clear disbenefit to the industry and consumer of being exposed to these costs, no matter how strong or weak a balancer an individual party might be from day to day. A reduction of PAR to the level(s) suggested, increasing the risk of suffering very high costs in a few half-hours, would present a barrier to entry and limit competition. This would be at odds with initiatives such as Secure and Promote which aim to encourage liquidity.

13. Increasing the incentive for parties to go long to mitigate exposure to SBP, demonstrated by Baringa's analysis indicating a rise in Gross Imbalance Volumes under all packages, would also perpetuate the free headroom that is acknowledged to be inefficient and a reason to alter the present asymmetric dual pricing system. (In their analysis for Wärtsilä, we note that Redpoint Energy/Baringa concluded that such 'free' headroom while in theory lessening the SO's need to hold reserve could result in actions leading to proportionately higher BSUoS costs, ultimately feeding through to consumers).

Question 2: Do you agree with our rationale for going to PAR1 rather than PAR50? Are you concerned with potential flagging errors, and would you welcome introduction of a process to address them ex-post?

14. As stated in our answer to question 1, E.ON believes that a PAR of 1MWh would not be appropriate. Firstly, PAR 1MWh would be less reflective of the true cost to the SO to balance the system than PAR 500MWh, as the SO takes balancing actions for different reasons over different periods that can all contribute to balancing the system in the half-hour in question.

15. Another problem with charging parties' imbalances the 'marginal' cost for balancing energy for that half-hour, is that balancing actions are not homogeneous but effectively priced more for the speed of delivery than for the energy itself. Consequently a fully marginal price would tend to be that of the most expensive i.e. fastest responding action taken in the BM. For any settlement period it might be right/economic for the SO to utilise either pumped storage or/and part-loaded plant, for instance, but PAR 1MWh would mean parties always paying for the dynamics of the fastest action taken.

15. We see that the quantitative analysis noted that the imposition of imbalance costs exceeding the SO's actual balancing costs through dual pricing may lead parties to 'invest or take actions to avoid this long term exposure to imbalance costs which are not justified in terms of added benefit to the system'. Even if the dual pricing regime is abolished, this concern must surely be exacerbated by a more marginal cash-out price.

16. A fully marginal cash-out might be the outcome from a theoretical perfectly competitive market. However, it arises in this context when all participants price at the marginal level as a result of perfect information. In practice, setting the imbalance price on the ultimate

MWh is not a substitute for a theoretically perfect market outcome. It simply burdens parties with an unmanageable risk.

17. In particular, intermittent generators and other small companies might have adapted their behaviour as much as possible, or be unable to find parties such as aggregators willing to hedge their risk. ACER's Electricity Balancing Framework Guidelines are clear that imbalances must be settled in a non-discriminatory, transparent, fair and objective way, with no special treatment for imbalances for generation from intermittent renewable energy sources. However as highlighted in our answer to question 1, it is not possible to predict when prices might spike in order to react and minimise your exposure, thus it would not be fair to expose parties to a fully marginal price that could rise very quickly to extremely high levels. In light of the impact that a fully marginal price could have on parties, particularly smaller suppliers and intermittent generators, and the other issues with PAR 1 MWh detailed above, E.ON believe that it would be unhelpful and counterproductive to pursue fully marginal cash-out prices.

18. Also, as some actions are for both 'system' and energy, we are indeed concerned that accurate flagging would be crucial to determine the marginal energy action. While Ofgem believe that the 'if in doubt, strike it out approach' may dampen cash-out prices, we see no alternative to that approach when no satisfactory means of splitting actions taken for both system and energy purposes has been determined. As Ofgem has identified, a sharper price would increase the impact of inaccuracies in the implementation of flagging, with maximum risk at a fully marginal price. While National Grid's Flagging Accuracy Report and Ofgem's P217 analysis suggested a high degree of accuracy, the P217 analysis did not examine times of more system stress when an error could have the most serious consequences. Even under normal conditions occasional errors must be expected, as indeed occurred on 26 April this year.

19. We note that National Grid advised the May 2013 BSC Panel that they are undertaking an internal review to investigate this instance and may seek to raise a change to address the limitations regarding changing flags, but that unless they can change their license statement, nothing can be done. While a potential solution has apparently been presented to the Imbalance Settlement Group, this issue must be resolved before a smaller PAR could be considered. In addition to a mechanism to deal with such occurrences ex-post, a disputes process should also be clarified; could the existing BSC trading disputes process be used? Ultimately, to avoid the risk of system pollution as did occur in April it would be best to retain the current PAR under which a misflagged action would have less impact.

20. From a European perspective, the Balancing Framework Guidelines do not stipulate marginal imbalance pricing. The latest draft Code v1.30 specifies that the imbalance price for shortage shall be not less than the weighted average of prices for activated Balancing Energy, or the value of avoided activation for the relevant period. Only the 'initial pricing method' for Balancing Energy shall be 'based on' marginal pricing; the means of calculating the value of avoided activation thereof, to be defined by the

relevant TSO. Thus we understand that for the TM imbalance prices do not have to be marginal.

21. If a change was to be made to GB arrangements in preparation for a Europe-wide balancing regime, it would appear more logical to alter BOAs to marginal pricing, i.e. to make them paid-as-cleared, in a scarcity situation paying each provider the price of the most expensive offer accepted, but this was dropped by Ofgem when narrowing the EBSCR's scope.

22. We would suggest that if the Authority did still desires a fully marginal price, a staggered implementation of a PAR reduction would be beneficial, with at least two years for the market to react to any change before changing the level again.

Question 3: Do you agree with our proposals for pricing of voltage reduction and disconnections, including the staggered approach?
and
Question 4: Do you agree with our assessment of the interactions with the CM and its impact on setting prices for Demand Control actions?

23. Attributing a cost to non-costed actions is desirable in theory. However it is clearly challenging in practice, and unclear whether VoLL would actually incentivise DSR, or feed through to prices. Prices may rise towards VoLL in the short-term, but we would not expect this to incentivise generation investment by feeding into the far end of the curve.

24. While London Economics' analysis suggests that £17,000/MWh is a fair reflection of the average VoLL for domestic and SMEs on a winter peak day, clearly using that value year-round would be disproportionately high. Consequently we understand DECC's proposal for £8-9,000/MWh in the CM. However having different figures for 'VoLL' per MWh in gas, the CM, and power imbalances, does complicate matters.

25. As National Grid has concluded in considering Supplemental Balancing Reserve, failure of the system to provide enough capacity might cost VoLL, but that is not necessarily an appropriate penalty to apply to individual generators having lower levels of reliability. We are concerned at the major impact that VoLL could have on parties through cash-out (particularly in conjunction with PAR 1MWh). A 'VoLL' of £3,000 rising to £6,000/MWh for incorporation of Demand Control actions in imbalance pricing is overly penal and could result in one half hour putting a company out of business.

26. We do not agree with the proposal for pricing of voltage reductions at the same level as disconnections hence putting a 'Value of Lost Load' figure into cash-out, when there is considerably less if any impact on the consumer. The historical analysis example of the application of £6,000 MWh on 11 Feb 2012 when voltage control occurred in four settlement periods, though there were no observed disconnections, is useful in highlighting how significantly these few settlement periods would have impacted parties.

27. £3,000/MWh or £6,000/MWh would not only be excessively high for supply interruptions or demand control but seems inconsistent with the gas SCR. While interaction with the CM is addressed by Ofgem, in the context of generators consuming gas to produce electricity, the relative levels of VoLL for gas and power would appear to incentivise CCGTs to continue generating even in a Gas Deficit Emergency.

28. More consideration of interaction with both the CM and gas VoLLs, and the impact that these figures could have on both existing market parties and deterring new entrants through added complexity, risk and credit requirements, is required in order to avoid multiple unintended consequences.

29. Ofgem suggests that ultimately the inclusion of VoLL in cash-out should help to avoid disconnections, but a warning prior to gate closure is necessary for parties to be able to react to help prevent the need for disconnections. Notifications to alert parties to such likely incidents would seem to be in the best interests of all concerned and we are concerned that at present the SCR does not propose to introduce these. If no such notification is made to the market, VoLL should not be incorporated in cashout.

30. In itself a staggered approach to implementation would be sensible if Ofgem decide to go ahead with this proposal. It also needs to be clarified whether VoLL would be indexed, e.g. to CPI, like CONE reviewed periodically, or reviewed with the aim of replacing it with a market-based solution? How might the VoLL number(s) applied change over time with the gradual discovery of 'true' VoLLs?

Question 5: Do you agree that payments of £5/hr of outage for the provision of involuntary DSR services to the SO should be made to non-half-hourly metered (NHH) consumers, and for £10/hr for NHH business consumers?

31. In theory paying customers for loss of supply seems reasonable. However this overlooks the fact that the system is designed to withstand loss of the largest infeed for which National Grid holds 0.7GW, not with such a high margin and gold-plated networks as to virtually guarantee that generation would always meet demand. Customers do not pay for such a service and would probably baulk at the cost of maintaining such a system. Rather, with a Loss of Load Expectation (LOLE) rising from 0.7 hours for winter 2013/14 to 2.9 hours for winter 2015/16 and Expected Energy Unserved (EEU) for the same timeframes from 659 MWh to 3,070 MWh in Ofgem's 2013 Electricity Capacity Assessment reference scenario, the expectation of occasional outages is built into the system.

32. To pay domestic consumers and small businesses under the circumstances suggested would risk increasing customers' expectation of zero LOLE/EEU, and of payment for every such incident, regardless of the cause.

33. More pertinently, we are concerned as to how this could work in practice; for instance

even how customers would be identified. Does customer mean per consumer, or per meter? To put processes in place to implement compensation for very occasional loss of supply would be complicated and costly, probably outweighing any benefits.

Question 6: Do you agree with the introduction of the Reserve Scarcity Pricing function and its high-level design? Explain your answer.

34. Overall we do not consider that a RSP would bring benefits to the market. Incorporating non-BM as well as BM STOR in cashout would be best, and the way that reserve is currently incorporated is cash-out is not ideal. However to improve targeting of reserve costs is challenging and it is not clear that an RSP would be better than the current methodology. Like the suggestion to increase PAR, it would not better reflect procurement costs to the SO. While the exact methodology that could be utilised is not yet fully established (for instance, does measuring margin mean useable margin)? clearly a RSP would add additional elements and complexity to imbalance calculations (more than would be removed by single pricing). There is a risk of extremely high costs in occasional half-hours if a RSP was implemented as suggested with the use of the suggested VoLL price, as would seem to have applied on a couple of days in April 2012 according to Ofgem's historic analysis. This would be another deterrent for new entrants in addition to overly penal to existing parties who just happen to be out of balance for the period in question.

35. In future, reforms may be needed to fit into a single European market with different requirements for reserve, DSR and cross-border balancing, and the Balancing Framework Guidelines do state that imbalance prices should include at least the cost of activated Balancing Energy from 'Frequency Restoration Reserves' and 'Replacement Reserves'. However as the Codes, definitions and implications for GB are not yet finalised, we think it prudent to hold back from introducing a complex function until we know exactly what will be required for the TM. Not only Electricity Balancing, but also Capacity Allocation and Congestion Management (CACM), Forwards Capacity Allocation (FCA) and the Demand Connection Code (DCC) are relevant; for instance, the current version of the DCC potentially requires domestic users to provide frequency response. The quantitative modelling's suggestion that the upward trajectory of SBP expected from impact of a RSP and costing demand control actions would be checked in 2030 by modelled long-term investments is little reassurance for parties who would have to incorporate the risk of incurring VoLL charges in their business plans in the shorter term.

36. Fundamentally we do not believe that the impact of cash-out prices, even with the potential to peak as high as £6,000/MWh, would have a positive impact on parties' long-term investment decisions. Primarily the CM and CfDs will be overriding influences with far greater impact than cash-out. However the fact that repeated changes to cash-out have been made over the past decade also makes them an unreliable investment signal; parties would be nervous at the prospect of potential future alterations regardless of whether changes to cash-out are implemented through the EBSCR.

Question 7: Do you agree with our rationale for a move to a single price, and in particular that it could make the system more efficient and help reduce balancing costs? Please explain your answer.

37. Yes, we agree that the dual price distortion should be removed. We note that ACER's Framework Guidelines can be interpreted to support either dual or single pricing (and many responses to the draft FG favoured a single price). However in GB, we agree that it has been clear for a while now, as Littlechild and Cornwall concluded in 2007, that the drivers for the dual price set up in 2001 are no longer a concern, and a single price is now preferable. The simplification of arrangements but more fundamentally the removal of the spread that parties with equal but opposing imbalances can face on their accounts owing to the current dual pricing system would reduce risk and thus costs. This could help to encourage new market participants and increase liquidity in the market. It could also minimise the tendency for parties to take a systematically long position bias and thus minimise the need for the SO to accept BM bids.

38. Sharpening cash-out prices would compound the spread that parties face under dual pricing, thus a single price would be essential if PAR was reduced, both to improve cost-reflectivity and to minimise these artificial costs to parties and ultimately consumers.

Question 8: Do you have any other comments on this consultation, including on the considerations where we did not propose any changes?

39. We continue to believe that dual accounts serve no purpose; vertically integrated companies supply the bulk of domestic demand and ultimately the consumer is paying for administration of this artificial arrangement. We do not believe that trading and hedging activity would reduce with a move to a single trading account; also, we understand that a single account is the norm on the continent.

40. In recognition that systems have been set up for managing dual accounts, implementing the P282 solution or pooling the imbalance post-event might be simpler than changing to a single account. Maintaining the dual arrangement but moving to a single price would minimise IT changes and costs while helping to minimise spreads.

41. In common with many views expressed in 2012's EBSCR stakeholder workshops and some responses to the initial consultation, as well as supporting the P282 solution to dual accounts, E.ON would also support post gate closure contract notifications. Effectively at present gate closure is nearer to 90 minutes than one hour; ex-post contract notifications of pre-gate closure trades should be straightforward to implement and could allow approximately 20 more minutes of trading rather than parties having to spend that time ensuring accurate notifications.

<u>Impact Assessment:</u>
Question 9: Do you have any comments regarding any of the three approaches we have taken to assess the impacts of the cash-out reform packages?

42. Undertaking two strands of quantitative analysis looking both to the past and to the future is helpful. Ofgem does explain that the historical analysis for 2010-2012 assumed no behavioural change whereas in reality changes would be expected in response to price signals; nevertheless we agree that it is still useful and that using the most recent three years' data appropriate. Although P217A did not apply pre November 2009, looking further back to incorporate more periods of system stress as in 2008 could also have been informative. We would hope that National Grid might be able to look back at any outstanding periods pre-2010 and determine whether actions were likely to have been taken for system reasons or not.

43. The assumptions made to facilitate the forward-looking quantitative analysis however were substantial, not least the assumption again of no behaviour change: parties not changing bidding strategies, and the SO not having to take system actions. While these and the other assumptions made may have been a practical choice for the modelling to facilitate comparison with Do Nothing in the shorter term, they are fundamentally unrealistic and this must be remembered when considering the output of the quantitative analysis. This is particularly important when looking at the model output for 2030, and when some of the packages show a negative impact in 2020 turning around or even producing what seems like a very optimistic outcome for 2030 on the basis of forecast investments in generation or DSR. Clearly in fifteen years behaviours will change, in some ways, and owing to national or European developments that cannot be forecast, whether specific to the energy market or wider issues such as the economic outlook.

44. However we are wary of the inclusion in long-term modelling of assumptions that have been made that parties can manage their imbalance exposure by making additional investments from a 'rational decision' comparing investment costs to expected savings in imbalance costs from improvements in demand/wind forecasting or plant reliability.

45. We also note that interconnector flows were not captured within the model, rather it was:

    '*assumed that given the spikiness of prices at times of system stress under the packages, these prices could be sufficient to incentivise interconnectors to flow into GB subsequently averting some of the remaining lost load. We assume the same response from interconnectors in all packages . . . . this is limited to a [sic] reducing EEU by up to 5,125 MWh, which is sufficient to remove all EEU under Package P5 in 2030'.*

    Further explanation would have been useful; it would seem sensible to exercise caution regarding the resulting projections of interconnector behaviour.

46. Fundamentally, we would caution against too much emphasis being put on model forecasts and suggest that more consideration should be given to input from market

participants. While Ofgem has acknowledged the limitations of the quantitative analysis, stating that it is only one of many factors to consider when making policy assessments, there is not a great deal of further explanation of some of the draft decisions beyond reference to that quantitative analysis. It is thus perhaps the qualitative analysis of which we are most unsure. The draft policy decision states that this has been based on logic, economic theory and discussions with stakeholders. However, while many parties have repeated that higher SBPs will not drive investment and the quantitative analysis is clear that it is primarily the CM that will be a driver of investment, the EBSCR documents appear to focus on the projections that long-term investment in more flexible capacity might be incentivised, despite the bulk of responses to the initial EBSCR consultation from potential investors asserting to the contrary.

Question 10: Do you agree with the analysis of the impacts contained in this IA? Do you agree that the analysis supports our preferred package of cash-out reform? Please explain your answer.

47. The quantitative analysis appears thorough albeit limited by the assumptions made; while there are inherent uncertainties in modelling out to 2030. This is emphasized however by the discrepancies with other models for 2030, such as the forecast of 109 hours of negative prices by 2030, in comparison with DECC's central EMR scenario of several hundred.

48. Even for 2020, however, the assumptions incorporated here mean that we cannot be overly confident in the 2020 or 2030 projections. When the projections are very specific but the differences between packages minimal, it is also hard to have confidence in deciding which might have the best outcome.

49. Fundamentally as per our answer to question 6, we are wary that the positive outputs of the modelling are limited in 2020 and longer-term being largely based on the belief that cash-out reform will drive investments that supply more capacity to the market and consequently lessen the risk of demand control and disconnections. We note that the quantitative analysis enabled Baringa to conclude only that in relation to the more substantial proposals, to increase the marginality of PAR, include an RSP and demand control actions, might result in:

    'possibly stimulating additional investment in demand side response and new generating capacity under a tight system'.

    Such tentative support for major changes to the present arrangements, in addition to those the market is already facing, we believe does not provide sufficient justification to implement them.

50. Thus we cannot agree that the analysis supports implementing any of the suggested packages. Radical changes do not seem justified when even with forecasts of long-term investment on the back of cash-out change that we believe are unrealistic, the impact on

the average domestic consumer bill relative to Do Nothing is only forecast to range from:

+£0.07 to -£0.15 *per year* in 2020, +£0.25 to -£0.61 in 2030 (without CM), to
+£0.08 to -£0.14 per year in 2020, +£0.31 to -£0.53 in 2030 (with CM).

(When long-term capacity investment in response to the packages is made through DSR; forecasts modelling investment through new CCGT instead having a greater negative and smaller positive impact on the average domestic bill in 2020, wholly negative with CM in 2030). Even incorporating costs and benefits expected to be passed on by parties, and savings in unserved energy and voltage control, the average £/MWh impacts for domestic consumers are very small, even by 2030, at:

+£0.02/MWh to -£0.05/MWh in 2020, -£0.17/MWh to -£0.44/MWh in 2030 without CM,
+£0.02/MWh to -£0.04/MWh in 2020, +£0.09/MWh to -£0.16/MWh in 2030, with CM.

These numbers are so small that the very serious impacts on parties that the packages could have cannot be justified, particularly when it is hard for these forecasts to be robust projecting forwards fifteen years, and the introduction of a CM significantly reduces any positive benefits forecast by 2030. Exposing parties to a steep rise in average SBP with the potential to rise to a maximum of £6,000/MWh (in comparison with the £503/MWh maximum reached in 2010-12), does not seem justified for the prospect of improving domestic bills by less than £1 per year. We believe that even these numbers may be overoptimistic as they do not seem to include parties' increased risk of being hit with extremely high charges even in only a few periods being factored into customer bills.

51. When the historical analysis demonstrated that market parties would have seen net imbalance charges of £10,100k-£12,200k under the packages in 2010-12, compared to £620k under Do Nothing, even if average charges would have risen only by a factor of 1.3-3.5, we do not believe that implementing these changes could be warranted without more confidence that the overall outcome for the market would be positive. The fact that the total charges would have been so much higher than average emphasizes the volatility that would make imbalance prices so difficult for parties to manage. Ofgem states that:

'*where prices rise to high levels, we expect that parties will respond to these prices and reduce the risk that these prices could endure for long periods'*

However, prices do not need to endure for long to have a significant negative impact on parties, while in order to respond, scarcity needs to be signalled in enough time to enable market participants to act where possible.

Question 11: Do you agree with the key risks identified and the analysis of these risks? Are there any further risks not considered which could impact on the achievement of the policy objectives? Please explain your answer.

52. Largely we agree with the risks identified, and the broad analysis. For instance, the conclusion that regarding imbalance risk and distributional impacts, smaller parties and intermittent generators would be relatively worse off overall is as we would have expected. As we have highlighted, it is the draft decision to implement a package of cash-out reform that would have this effect while exposing all parties to unmanageable costs that seems contrary to other Ofgem initiatives to increase liquidity.

Question 12: What if any further analysis should we have undertaken or presented in this document? Do you have any additional analysis or evidence you would like to contribute to support the development of the EBSCR towards its Final Policy Decision?

53. More modelling of times of system stress would have been most valuable, particularly acknowledgement of the potential impact on parties of those periods where cash-out costs for one half-hour could exceed those for several months.

54. An indication of a possible means to address flagging errors and clarification of a dispute procedure could have been useful as these would be necessary before any move to a smaller PAR, although we do not support a reduction in PAR partly on the basis that any such errors could potentially have serious consequences for parties (e.g. cashflow), even if addressed ex-post.

<u>In conclusion</u>

- We are concerned that the increased risk to parties of more marginal pricing would not help to incentivise investment in either flexible capacity or efficient balancing, merely perpetuate a long system as parties tried to avoid penal SBPs.

- A marginal cash-out price incorporating VoLL at the level(s) suggested, whether for disconnections, demand control or even potentially use of reserve, could have a catastrophic effect on parties. This element would be detrimental to liquidity.

- The potential benefits to customers are very small and uncertain, and could be negated by risk premiums which Suppliers would have to factor into prices.

- Cash-out must be fit for purpose to deal with a changing market and generation mix, without rushing changes to existing arrangements. Radical changes should only be considered once we have the final detail of the European TM requirements.

If you would like to discuss this response, please do not hesitate to contact me.

Yours sincerely,

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