Annex 1 : SSE Response to Electricity Balancing SCR Considerations

1. Approach

SSE welcome Ofgem's initiative to undertake a comprehensive and holistic review of electricity imbalance cash-out and energy balancing arrangements to understand whether the arrangements remain fit for purpose in an evolving market.

However, whilst recognising Ofgem's desire to better influence European developments, SSE remain uncertain that the timing is right to undertake critical policy decisions regarding significant electricity balancing reform. There are a number of substantial market developments and reforms ongoing at present, particularly EMR and European Network Codes that have a high level of interaction with electricity balancing arrangements. SSE is concerned about the potential for unintended consequences in formulating detailed design of policy options for cash-out reform prior to key decisions under EMR and European Network Codes; such consequences having the potential to undermine the operation of the market and/or lead to reversal of change and/or expenditure of nugatory costs.

In particular, there is a real danger that the EMR Capacity Mechanism and a desire for more marginal, extreme cash-out prices could cut across each other. This creates even greater uncertainty in an area where current levels of uncertainty are already impacting and delaying needed investment. The SCR has the potential to compound this uncertainty. It may be more efficient to allow a firmer position to develop on the design of the Capacity Mechanism prior to undertaking balancing reform.

It is vital therefore that the timing of key interactions between the varying policy developments (and implementation thereafter), is optimised, well understood and well signalled to the market in order to minimise investor uncertainty. Development of a coherent, co-ordinated timeline setting out key milestones and interlocks for interacting policy developments would be a helpful step in understanding what the optimum timing might be.

Whilst SSE have attempted to provide a view in isolation on each of the primary and secondary considerations presented in the consultation document, it is difficult to provide an in depth assessment of options and impacts until a package of the consultation options has been determined that allow a better determination of key interactions and thus potential behavioural impacts on the market. Again this assessment would be better informed if key decisions regarding the EMR Capacity Mechanism and European Network Codes were in place prior the presentation of these packages.

With the above in mind, SSE are uncertain that publication of a draft policy decision document in March 2013 is the right timing. It may be more appropriate to aim to publish an interim document by this date setting out the proposed options for reform packages, prior to any indicative decision or minded to statement. At the very least, it may be worth Ofgem engaging with industry prior to publication its draft policy decision in order to present its thinking on the preferred package of proposals, along with assumptions, to allow a more in depth understanding and discussion of the impact of the whole package of reform.

2. Primary considerations

2.1 More marginal main cash-out price

SSE support Ofgem's view that current cash-out prices are dampened and do not sufficiently incentivise the continued operation of low load factor, flexible thermal plant in the market as they are unable to realise sufficient scarcity rent. Equally, prices need to be able to rise to a level that makes it economic for the demand-side to respond when the system is stressed, which will not be achieved with dampened prices.

SSE would therefore support a move towards a more marginal main cash-out price, on the critical assumption that the price setting stack of actions is not polluted by out of price order system actions.

With this in mind, we believe that the P217A analysis presented suggests that the tagging and flagging process for identifying and separating out system actions from the price stack is broadly fit for purpose and are encouraged that the GBSO is procuring and designing its new EBS with a view to further improving and refining this process. Equally, SSE do not believe that the same concerns exist with regard to market power as were apparent at NETA, particularly given other policy interventions such as TCLC, REMIT and so forth. Therefore the current environment seems better suited to a move towards a more marginal or fully marginal cash-out pricing methodology.

To the extent that forward trading sentiment is driven by conditions in the prompt market, cash-out needs to be seen as a credible threat by traders in the market to sufficiently incentivise forward trading. Any dampening effect on prices reduces its credibility and negatively impacts liquidity on the forward curve. SSE therefore view a move towards a more marginal pricing mechanism as a key aspect of the proposed reforms, as it may help encourage greater liquidity in forward markets, in turn reducing transaction costs.

Notwithstanding the above, as highlighted above SSE remain concerned that the detailed interactions between a more marginal cash-out price and the EMR Capacity Mechanism are not and cannot be fully understood until it is clear what the final proposal for the Capacity Mechanism is. We would urge Ofgem to carefully consider the danger of unintended consequences that may arise were policy decisions taken prior to the design of the Capacity Mechanism being understood.

2.2 Single or dual cash-out prices

SSE agree that market conditions have changed sufficiently to allow consideration of a single price structure, i.e. the GBSO has proven to be a competent and efficient balancer and market power concerns are not as prevalent as at NETA given other regulatory interventions. However, SSE consider that the incentives for parties to balance their own positions or be exposed to the cost of residual balancing should remain, and dual cash-out is more effective in achieving this. It may be appropriate in this context to reconsider whether the reverse price formulation is an appropriate reflection of the GBSO costs of residual balancing.

Whilst accepting that a single price would ease participation in the market for smaller players, we would be concerned that it would undermine the incentives to trade forward for small generators and suppliers who will end up price taking the single price, in turn creating greater uncertainty and cost in balancing the system for the GBSO, and not targeting those costs to those who have created them. Were Ofgem to choose this option, then it is crucial that it is done so in the knowledge that a robust market for financial products would be necessary to facilitate risk management of price volatility; and that a way of targeting excess balancing costs incurred by the GBSO through use of system charging or a separate price component is developed, as well as a redistribution mechanism given that single price may still under or over recover the GBSO's costs.

2.3 Single or separate trading accounts

SSE note that much of the arguments for and against single or separate trading accounts are captured in BSC Modification P282, which is currently being progressed, and can be utilised to achieve the same practical effect. As such it is appropriate for Ofgem to give due consideration to the proposed modification in the context of its final proposed package of reforms.

The benefits to parties of operating single rather than dual trading accounts seem marginal, given that the rules do not prevent parties from trading between accounts to balance their two positions currently. SSE see a small administrative risk management benefit in removing the need to execute trades that balance between the two accounts and thus removing the imbalance consequence of failure to do so.

SSE would support a move to single trading accounts, if it can be demonstrated that the overall benefits associated with parties being able to better balance their own net position, through natural offsets in their portfolio (thus reducing the need for GBSO to act as residual balancer); outweigh the potential increase in costs that the GBSO may face in reduced optionality from "free" headroom, and increased balancing uncertainty associated with FPNs changing more frequently immediately prior to gate closure.

SSE agree that this issue becomes irrelevant were a single cash-out price to be adopted.

2.4 Pay-as-bid or pay-as-clear for energy balancing services

SSE agree that theoretically, given a homogenous product, sufficient competition and perfect information, pay-as-clear for energy balancing services would be the most suitable method to adopt, as it would encourage generators to bid in at short-run marginal cost and avoid the inefficiencies of having to second guess the economics of the marginal plant that pay-as-bid leads to. This in turn should lead to an optimal clearing price as generators can be confident of earning infra-marginal rent.

In practice however, whilst SSE believe that market power issues are not as prevalent today and regardless are subject to separate interventions where there is a perceived localised issue (e.g. TCLC); we believe that products in the Balancing Mechanism are not homogenous and are taken by the GBSO to resolve many issues in a single action, which the GBSO is obligated and incentivised to do to ensure optimal, efficient and synergistic procurement of balancing services. This often results in the GBSO taking bids or offers out of price merit order to allow it to resolve system issues or energy and systems issues as a bundled action.

Furthermore the Balancing Mechanism is set up in such a way that it has a single counterparty, the GBSO, accepting simple rather than complex bids and offers as it needs to on a bilateral basis, rather than through an auction. This set up does not lend itself to a pay-as-clear model, particularly the need for plant in differing states of production readiness to wrap up certain costs (e.g. no-load costs, start-up costs, shutdown costs) in a single price rather than differentiate cost components in a complex bid/offer price structure.

Were the BM to move to an auction, then it is likely to have to be an energy only auction, bringing with it the associated likely rise in costs of requiring the SO to separately procure energy and system products or the need to construct an unconstrained schedule and the loss of price reporting transparency to the market. Equally the auction would need to optimise to a given time horizon sufficiently in advance of real time to allow the GBSO an ability to redespatch plant to manage system constraints.

It appears to be possible to apply the tagging rules developed as part of BSC modification P217A to provide a reasonable proxy of appropriate energy actions to be cleared given error rates reported in the P217A analysis, so this approach, whilst imperfect, could probably be made to work, but without much improved information and transparency from the GBSO on active constraints on the system, it may be difficult for the market to forecast where the clearing price would be set a with a corresponding knock on effect to cash-out volatility.

Notwithstanding the above, any actions taken out of merit order that are priced at a level above the clearing price (i.e. constraint actions) would still require compensation on a pay-as-bid basis or those providers will not recover their costs, reducing their likelihood to continue to offer balancing services into the future.

2.5 Attributing a cost to non-costed actions

In principle, SSE support Ofgem's aim to reflect a cost for voltage control and involuntary demand disconnection actions into cash-out prices, in order to properly incentivise and remunerate voluntary demand side response and storage. We would caution on the use of an administered VoLL price in cash-out. We would urge Ofgem to be very precise and considered about the exact trigger events that would cause the price to be applied (e.g. notice of imminent demand reduction), in order to signal an incentive for the market to respond. Defining incorrect trigger points would simply result in cash-out becoming a very punitive, unmanageable penalty, rather than an appropriate signal to voluntarily disconnect.

We agree with Ofgem that VoLL will resolve across a spectrum of values for different demographic groups of customers, depending upon the relative price elasticity of those groups. We would welcome further information and analysis by Ofgem informing the optimum level of VoLL that could elicit a meaningful demand side response from more price elastic customers. With this in mind, it might be appropriate to consider whether different values for VoLL apply to different trigger events, to ensure the most appropriate response. With this in mind, we would urge Ofgem to consider whether setting a fixed price VoLL provides the most efficient outcome for consumers, as there is a danger that it sets a de-facto floor price expectation in the contracted market for DSR, thus significantly increasing the cost of providing such services. Such costs would ultimately have to be borne by inflexible consumers.

In principle, SSE also support the idea that customers disconnected involuntarily should be compensated for that disconnection. However, we do not think it is appropriate to fund this compensation through residual cashflow as the total imbalance fund could well be in deficit given that metering values will have reduced relative to contracted positions, leaving Suppliers longer. This leads to a slippery slop of trying to estimate what a given Supplier's deemed position would have been had the demand reduction action not been taken, with all the potential opportunities for dispute that follow. The arrangements should certainly not result in balanced Suppliers paying for the costs of involuntary disconnection. It may be more appropriate to consider an alternative means of funding through use of system arrangements.

In practice however, even were the right means of funding compensation determined, there appear to be significant implementation difficulties. Suppliers are left with the highly complex issue of determining a) which customers should be compensated in such circumstances (e.g. did a customer in a given area voluntarily or involuntarily interrupt?); and b) what each customer's share of the total compensation fund should be (based on what they were consuming immediately prior to interruption (which dumb meters would not support); or what they would have consumed had they not been interrupted; or a fixed amount per customer?). Suppliers would need very clear rules and guidelines from Ofgem on the rules for a) determining qualifying customers and b) allocating the total compensation fund.

Additionally, Ofgem need to consider the value of any electricity VoLL price that is proposed in the context of Gas emergency cash-out arrangements and cross-border pricing to ensure that unintended VoLL arbitrage opportunities are not created, with subsequent impacts on security of supply.

Whilst agreeing in principle with Ofgem that unpriced demand reduction actions should be accounted for in cash-out, we would urge Ofgem to consider carefully whether this measure is absolutely necessary once the final design of the EMR Capacity Mechanism is determined, given the potential for extreme cash-outs to send smaller market players out of business almost overnight should they become exposed to system buy price at the wrong time, and the subsequent contagion effect that may follow in the market.

2.6 Improved allocation of reserve costs

SSE agree that treatment of options fees associated with contracted reserve can have a dampening effect on cash-out prices, given the inherent inefficiency of using historical weighted averages to target the associated buy price cost adjustment. Equally, SSE agree that only reflecting the utilisation fee in periods where the option was exercised and despatched, can have the effect of pushing energy-only offers in the Balancing Mechanism out of merit.

In principle therefore we support Ofgem's aim to establish a better mechanism to allocate and target reserve costs in cash-out price formulation. This should include exploring a better means of reflecting option fees in the price, but also inclusion of non-BM utilisation fees as a price adjuster. Of the options presented by Ofgem's in its workshops, we feel that an uplift to a BOA action when reserve is utilised is worth considering in further detail, although Ofgem would need to determine how an equivalent arrangement could be established for non-BM STOR.

In determining any solution however, it is crucial that Ofgem ensure that there is provision of appropriate information to the market to allow the effect on cash-out to be reasonably predicted. This is particularly true of non-BM STOR actions, which is not transparent to the market currently. SSE would be opposed to an ex-post allocation of reserve costs, which is clearly the most accurate means of doing so, as it would not facilitate the market being able to reasonably predict and respond to prices prior to gate closure.

Finally, SSE consider that too many issues arise in trying to deal with the retargeting of costs associated with reserve creation. Too many questions arise about the subsequent treatment and pricing of actions that could have been taken were the reserve creation action not taken in the first place, to make any proposed methodology difficult and complex to implement, as well as making the effect on prices opaque and unpredictable to the market.

2.7 Balancing energy market (BEM)

We find it difficult to provide any meaningful comment on this policy option, as the mechanics of the proposal are insufficiently clear to take a view. SSE would welcome further detailed proposals from Ofgem on how this market might work in practice.

Currently, from what little we do understand at a high level, it is difficult to see how this option provides any additional benefit above the current energy market arrangements (with a reduced gate closure), particularly given that the BEM seems to give no consideration to plant dynamics and ability to deliver. This facet would on the face of it either a) increase the “undo” actions or option costs required to be taken by the GBSO to resolve an unfeasible despatch model arising from the BEM; or b) restrict the type of plant that could sell into the market, were the ability to honour dynamics to be a key consideration. Whilst it may separate energy and system action procurement, allowing a pure energy price signal to be determined, there is highly likely to be an increase in cost to the GBSO from losing the synergies associated with procuring bundled, optimised products.

Finally, this model assumes an incremental improvement in the forecasting of NIV by GBSO that may not be achievable in practice.

2.8 Alternative arrangements for renewables

SSE do not consider that there is a need to intervene with a centrally administered set of arrangements for renewable generators at this point in time and support Ofgem maintaining a monitoring role in the development of independent aggregation services.

Whilst we agree that pooling of fluctuations over a geographically-diverse portfolio provides imbalance benefits, we are not convinced that a single national aggregator provides any greater incremental benefit than would be obtained from commercial aggregators or PPA consolidators operating in a similar way. Such commercial aggregators/consolidators might also be able to call upon other flexibility options within their portfolio to better manage such imbalance fluctuations and volatility. This will be even more apparent once EMR has been fully implemented and renewable generators receive a means of mitigating price risk. At this point commercial aggregators/consolidators should be able to better reflect pure imbalance risk premia in pricing structures without the need to account for energy market price risk, and thus offer improved terms to generators.

SSE would also be concerned that operating the entire renewables fleet from a single central view of the world may detract from innovation as well as trading liquidity. Markets trade based on differing interpretations and views of information; if all players have the same centrally provided view, it is more difficult for opposing buy and sell positions to formulate. There also seems little incentive to innovate and differentiate were central arrangements mandated owing to a lack of competition in service providers.

We are unconvinced about the merits of the GBSO taking on the imbalance risk associated with intermittent renewables – it is probably not in the best position to manage these imbalances, and unless appropriately incentivised and controlled this may result in cost escalation to those exposed to BSUoS or an undue distortion in the traded market.

3. Secondary considerations

3.1 Improved provision of information

SSE consider that there is already an enormous amount of transparency and information in the GB market, that can be usefully interpreted and acted upon in day to day commercial operations. It is difficult to see too many areas where information could be produced that could usefully be relied upon, but welcome Ofgem's desire to understand whether GBSO forecast information of NIV as an example could be improved upon.

One area that SSE consider could be improved is provision of information on utilisation of non-BM STOR contracted to the GBSO, which is not transparent at the moment and can be a sizeable share of the reserve market. Provision of this information would be particularly important were Ofgem to decide that non-BM STOR utilisation costs should be included as relevant energy actions when allocating reserve costs in cash-out.

3.2 Creating a reserve market

We see little value in creating an organised daily reserve market, where participants could either trade between themselves or with the GBSO. The energy market should deliver this short-term ability to sell out uncontracted generation and any attempt to set up a separate market would simply further drain liquidity in the short-term energy market.

We believe that it is also likely to drive up the cost of reserve procurement to the GBSO, as it is required to procure over a shorter timescale and can no longer rely on a discounted price. Equally, whilst recognising a key interaction with the EMR Capacity Mechanism, this is unlikely to support security of supply, as certain low load factor thermal plant that rely upon the certainty of an annual reserve service option fee to stay open, may be forced to mothball or close if having to face the uncertainty associated with participating on a daily basis in a reserve market. The current GBSO bilateral process is competitively tendered and serves its purpose well, so SSE do not see a case for change.

3.3 Amending gate closure

As a minimum SSE believe that a separate gate closure should be established for contract notifications and FPNs. Currently the within day market effectively closes 1.5 hours ahead of delivery, in order to allow those taking on within day notification risk (principally power exchanges), to ensure that contracts are notified, acknowledged and confirmed as accepted by the ECVAA prior to formal gate closure 1 hour ahead of delivery, thus losing a half-hour window of opportunity to trade out imbalances that could be valuable for intermittent generators in particular. With systems technology it should be possible to allow appropriately time-stamped contract notifications to be submitted in the hour between gate closure and real time delivery. Thus in effect creating a separate FPN gate closure (1 hour ahead) and a contract notification gate closure (say at 30 minutes ahead to allow PXs to manage administrative and system risks of notifying). This would allow the traded market to continue to trade right up to gate closure for physical positions.

Any move of physical gate closure from 1 hour ahead of real time to closer to real time (e.g. 5 minutes), is likely to be beneficial for physical market participants whose forecast certainty increases closer to real time, e.g. wind generation, but only to the extent that sufficient liquidity exists in the traded market this close to real time to trade out imbalances. However, this potential benefit for parties needs to be weighed against the increase in cost that the GBSO, and thus those exposed to BSUoS charges, would incur as a result of needing to procure additional ancillary service and reserve options to enable it to balance in real-time, and how this might subsequently impact energy markets (i.e. could increasing levels of plant procured under option to the SO decrease liquidity in energy markets). SSE would urge Ofgem to undertake additional analysis in conjunction with the GBSO to determine the cost benefit case prior to making a decision.

Finally, it is not certain to us who would trade imbalances in an ex-post market, so we see little value in pursuing this option.

3.4 Residual cashflow reallocation cashflow

SSE agree that it is desirable to minimise residual cashflows arising from total imbalance amounts paid or received, which is best achieved through trying to properly and accurately reflect the energy balancing costs faced by the GBSO in the imbalance price. Nevertheless, any imbalance price incentive mechanism is still likely to over or under recover the actual cost of the service provided to a greater or lesser extent, so a mechanism to redistribute the associated costs or revenues seems unavoidable, unless absorbed by the GBSO (e.g. deducted or added to BM cashflows), which in turn may result in unintended consequences.

3.5 Reverse price

SSE agree that it is appropriate to consider reverse price formulation depending upon the main price considerations within the overall package of reform.

3.6 Information Imbalance charge

SSE agree with the circumstances identified where consideration of an information imbalance might prove relevant. However, we do not consider that there is a need to apply information imbalance charging, given Grid Code obligations to submit and adhere to FPNs, as well as wider transparency and reporting requirements, such as REMIT, which require a generator to disclose its intentions. Whilst we recognise that intermittent generation currently poses a problem to the GBSO with respect to accurately signalling intended output, we believe that this is better addressed through continuation of current initiatives within the industry. Were information imbalance charging to be introduced, then a reduction in Gate Closure ought to be delivered in parallel in order to allow intermittent generation a better chance of signalling its forecasted generation and minimising its exposure.

<u>Annex 2 : SSE Response to Consultation Questions</u>

Question 1 : Do you agree with the approach and the proposed stakeholder engagement throughout the SCR ?

We welcome the stakeholder engagement outlined by Ofgem and encourage Ofgem to maintain a continual dialogue with stakeholders, however we are not convinced that the timing is right given the many policy areas under development, their critical interactions and the risk of unintended consequences if decisions are made prematurely.

Question 2 : Do you have any evidence that you would like to submit that may be relevant for any aspect set out in this document ?

Not at this point in time.

Question 3 : What is your view on the interactions between our considerations and aspects of the EU target model ?

Whilst it is helpful for Ofgem to understand a desired outcome when considering these interactions, it is crucial that the interactions between these policies are carefully considered and understood prior to making any key decisions in order to avoid the risk of unintended consequences and/or nugatory costs (which would most likely weaken investor confidence).

Question 4 : Do you feel there are any further alternatives to the reform options presented under our primary considerations ?

The options in isolation seem a reasonable wish list of long-held (and some not so long-held) concerns with aspects of the current arrangements. However, SSE need to better understand the overall package of proposals to be in a position to suggest whether an alternative package may better serve the needs of an orderly market to function.

Question 5 : What other benefits or drawbacks can you identify for each of our primary considerations ?

Please see comments in Annex 1

Question 6 : Which of the reform options considered under each of our considerations do you believe would provide the most efficient balancing incentives and why ?

Please see comments in Annex 1. However it is difficult to comment meaningfully to this question without understanding the overall package of reforms desired, as there are trade-offs between options depending upon their interactions with other aspects of the arrangements.

Question 7 : Do you agree with the initial findings of the preliminary analysis of the last modification to the cash-out arrangements, P217A ?

We note that the analysis is heavily reliant upon information provided by the GBSO that it is difficult for stakeholders to independently verify and therefore trust that Ofgem has rigorously tested the data provided to them for analysis. On the basis of the information presented, the initial findings appear to be reasonable.

Question 8 : What additional analysis could be done as part of the SCR around modification P217A and the flagging methodology it introduced ?

It may be prudent to understand to what extent the degree of error in tagging is expected to improve with the forthcoming introduction by the GBSO of its new EBS; does this improve or worsen confidence in establishing a clean energy imbalance price by 2015 ?

Question 9 : Do you agree with our rationale for considering making cash-out prices "more marginal" ?

Yes, but the interactions with the proposed EMR Capacity Mechanism need to be fully understood prior to making any firm policy decisions.

Question 10 : Do you agree with the circumstances we have identified in which secondary considerations are important ?

Broadly yes, but some considerations may not be as important as envisaged given other checks and balances in the market. See comments in Annex 1 above.

Questions 11 : Do you have any other comment on the secondary considerations presented ?

See Annex 1 above.