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Andreas Flamm
Wholesale Markets
Ofgem
9 Millbank
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22 October 2013

Dear Andreas,

Electricity Balancing Significant Code Review – Draft Policy Decision

Drax Power Limited ("Drax") is the operating subsidiary of Drax Group plc and the owner and operator of Drax Power Station in North Yorkshire. In March 2009, Drax acquired an electricity supply business, Haven Power Limited ("Haven"); Haven supplies small and medium sized business customers and provides an alternative route to market for some of Drax's power output.

A full response to the questions detailed in the consultation can be found in Annex 1. In summary, our main comments on the Draft Policy Decision are as follows.

We do not consider that PAR1 strikes the right balance between incentivising the correct market participant behaviours and ensuring against the introduction of disproportionate risk into the cash-out arrangements. The risks associated with high SBPs under PAR1, and especially the introduction of VOLL into the cash-out arrangements, are disproportionate in our opinion. The proposal risks increasing market concentration and the risk premium inherent in the market. The costs of this would ultimately be borne by end consumers. A higher, more moderate PAR value and lower VOLL value will still deliver the correct incentives to market participants whilst avoiding the disadvantages noted above.

We fundamentally disagree with divorcing the costs of STOR from the pricing of STOR into cash-out. The Reserve Scarcity Pricing (RSP) Function is in no way more cost reflective and will result in additional complexity and disproportionate risks in the market, with the same potential consequences as noted above.

There is not that much difference between a single and dual cash-out price; the safest position is for a party to be balanced under both methods. However, we have a slight preference for retaining the dual cash-out price as:

1. There is less complexity associated with what the optimal trading strategy should be under a dual pricing method.
2. Single cash-out pricing tends to favour large vertically integrated parties but does not benefit small suppliers and independent wind generators to the degree assumed by Ofgem. The increase in the marginality of cash-out pricing is of greater significance to these industry players.

At a very high level, the accompanying Impact Assessment shows that the benefits (where these are apparent) of Ofgem's proposed package are very small relative to the costs associated with a multi-billion pound industry. Therefore we struggle to conclude that the proposals justify implementation.

Finally with regards to implementation, some of the proposals, in particular the RSP Function and costing of voltage control and disconnections, will take a long time to be developed (assuming Ofgem decides to implement its Draft Policy Decision). In particular, this will be the case if Ofgem leaves much of the detail to be developed by industry code working groups. Therefore, Ofgem should be aware that quick implementation is unlikely in such circumstances. However, the likelihood of long implementation timescales is worrying in the context of the investment that is required to be made in the power sector in the coming years. The continuing uncertainty is unhelpful in this regard. For example, without certainty of the future cash-out arrangements, market participants will be hindered in evaluating the risk of participation in the first capacity auction. As a minimum requirement, clarity is needed as soon as possible on Ofgem's final decision.

If you would like to discuss any of the views expressed in this response, please feel free to contact me.

Yours sincerely,

By email

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Regulation and Policy
Drax Power Limited

Annex 1

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

There are perfectly good reasons for making cash-out prices more marginal as discussed in Ofgem's consultation document. However, it is important that a balance is struck with regards to how marginal cash-out prices should be. On the one hand, cash-out prices should be marginal enough to incentivise the behaviour of market participants, but on the other hand, should not be so marginal that the risks placed on market participants are disproportionate. We have concerns that implementing PAR1 will not strike the right balance between these conflicting objectives, and consider that more analysis needs to be undertaken to discover what PAR value delivers the right balance. We discuss our concerns in more detail in answer to Question 3.

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?

As discussed in answer to Question 1, we have concerns with the use of PAR1 in that it does not balance competing objectives optimally. On the face of it, PAR50 delivers a better balance between incentivising correct behaviour and ensuring that disproportionate risk is not introduced into the cash-out arrangements. However, evidence has not been presented to justify PAR50 as necessarily being the correct PAR value either. In particular, the imbalance prices modelled under PAR1 and PAR50 are not materially different. More analysis is required to ensure that whatever PAR value is adopted, the balance between incentivising appropriate behaviour and maintaining proportionate risk is correct. We discuss our concerns in more detail in answer to Question 3.

With regards to ex-post correction of flagging errors, in short it may be worth adopting. However, one can only judge the suitability of it once the PAR value has been decided. As a general rule, ex-post correction of flagging errors will become of greater value as cash-out prices are made more marginal.

Question 3: Do you agree with our proposals for pricing of voltage reduction and disconnections, including the staggered approach?

We do not necessarily disagree with pricing voltage reduction and disconnection actions, however we are concerned about the values Ofgem is proposing (£3,000/MWh initially, rising to £6,000/MWh once the Capacity Market is introduced). Similar to the proposals to introduce PAR1, we do not consider the proposals on voltage reduction and disconnection strikes an appropriate balance between incentivising behaviour and ensuring that the risks placed on market participants are proportionate. Specifically, we consider that the risks placed on parties, as a result of a high VOLL value and potentially high SBPs caused by high accepted offer prices, are disproportionate. Below we provide an illustrative example of the risk that a generator is more likely to face as a result of moving to PAR1 and/or introducing pricing for disconnection and voltage control.

Assume a 500MW CCGT that is not particularly profitable, achieving a spark spread equal to £5/MWh. That equates to a gross margin of approximately £9m per year with a 40% load factor (note this is not the same as pure profit). A plant trip from full load for two hours at a SBP equal to £3,000/MWh would result in an imbalance charge of £3m (please note the generator would be unable to trade out its position in the first two hours after gate closure). While this scenario can be characterised as a low frequency high impact risk, National Grid's Winter Outlook 2013/14 assumes that thermal plant availability is around 85%. This indicates that whilst most generators will avoid this penalty, at least a handful of plant will face the penalty at any one time. Therefore it represents a genuine risk to a generator that it cannot fully insulate itself from.

A CCGT faced with this kind of penalty will be forced to hold more credit to mitigate this risk. Initial thoughts on the credit implications of this change indicate that there will be much more expensive credit requirements under the BSC and on power exchanges. As such, it is questionable whether a generator (particularly operating on a merchant basis) could bear the sort of risk illustrated above.

The key point the example above demonstrates is that whilst highly profitable, creditworthy entities can be expected to absorb these risks more comfortably, low or unprofitable plant will struggle. However, it is this plant that is expected to provide an adequate capacity margin.

However, we also note that the wholesale market could potentially adjust to mitigate the risks market participants will face as a result of Ofgem's proposals. To mitigate the increased risks faced by market participants, forward power prices will have to increase significantly to reflect the increased imbalance risk and thus offset the detrimental impact (by increasing generators' gross margin). In addition, marginal pricing will tend to increase generator prices in the BM as well as increase STOR prices. Increased prices may be expected to increase the potential for competition and market entry. However, from a practical perspective it should be noted that to allow wholesale market prices to adjust to mitigate the risks associated with the changes to the cash-out arrangements, there will need to be sufficient notice of implementation (at least two years probably) e.g. if an Ofgem decision is made in 2014, implementation should follow in 2016. This is because the majority of power will already have been sold forward, so there will be a mismatch between the formation of imbalance prices and forward prices if implementation of Ofgem's proposals is not delivered with adequate notice.

However, there is also a risk that if increased forward prices do not materialise, there may be detrimental impacts on forward liquidity, as a key mitigating tool for generators may be to sell less power forward and rather wait until day-ahead. This would be counterproductive to Ofgem's work to improve forward liquidity.

Therefore depending on how the wholesale market adjusts to factor in the increased risk of the imbalance arrangements, it is possible that the end result for consumers will be to increase bills, as the increased costs associated with managing the risks filter through (unless this is offset to some degree by improved market efficiency). This may or may not represent a more efficient market outcome. We note though that at this stage Ofgem has not demonstrated that it represents a more efficient market outcome.

Nonetheless, it is critical to note that even if the wholesale market adjusts sufficiently, generators will still not be able to completely protect themselves from the risk of extremely high imbalance prices as no power station is 100% reliable. Therefore, generators will continue to face a risk they may not be able to recover from. As such, the important question for Ofgem is whether it:

a) Wants to send a strong incentive for parties to balance and invest in more reliable technologies, whilst at the same time;
b) Be prepared to place high impact, single event risks on parties they may not recover from.

If the answer to both a) and b) is yes, the voltage control & disconnection and PAR1 proposals will meet Ofgem's requirements. We believe that it is unnecessary to introduce this level of risk into the market, with the resultant cost increases they imply. We consider that a major potential consequence of these proposals will be to encourage greater industry consolidation and concentration, as well as deter market entry. This will undermine efforts being made by Ofgem to encourage new independent participants to the electricity industry and increase liquidity. This is because a portfolio player that benefits from market diversification, rather than a single market entity, will be better placed to manage these very high single impact risks. Moreover, we can infer from evidence sourced from weekly reports produced by Elexon that the absolute imbalance faced by small suppliers is far larger relative to that faced by larger suppliers. This provides further indication that smaller parties will be exposed to relatively greater levels of risk associated with PAR1 and costing voltage control and disconnections. These disadvantages will not be sufficiently offset by the potential wholesale market adjustment in our view.

Importantly, it should also be noted that marginal pricing will tend to incentivise reliability rather than flexibility as suggested throughout the consultation document. There is far too much 'stick' and hardly any 'carrot' to incentivise investment in flexibility. In any case, there is little evidence presented to suggest that major efficiency gains can be achieved through improved reliability. Therefore, it is unlikely that sufficient efficiency improvement will be made to offset potential wholesale price increases. Overall, the above indicates that the risks are far greater relative to the limited benefits of the proposal.

We consider that a higher PAR value and a lower VOLL value than those proposed can easily incentivise parties to balance and invest in reliability, whilst avoiding market participants being placed in a position of extremely high risk. We believe that Ofgem should reconsider these values by undertaking analysis to determine what would be an acceptable level of risk to place on a market participant. In particular, we are worried about the lack of analysis on the effects on credit requirements resulting from Ofgem's proposals. This analysis should be undertaken as a priority.

Finally, we note that the implementation of a cost for voltage control and disconnections has yet to be developed to a satisfactory degree of detail. In particular, the method of calculating demand control volumes, which is only briefly discussed in the consultation document, does not provide us with much confidence that the imbalance charges these volumes will be based on will be particularly robust.

Question 4: Do you agree with our assessment of the interactions with the CM and its impact on setting prices for Demand Control actions?

There are clearly interactions between the cash-out arrangements and the Capacity Market, in particular the determination of Capacity Market penalties. The sooner that Ofgem can provide certainty of future cash-out rules the better. Early certainty will allow market participants to more quickly value the relative commercial attractiveness of the capacity market and thus make more efficient commercial decisions. Specifically, without certainty of the future cash-out arrangements, market participants will be hindered in evaluating the risk of participation in the first capacity auction.

In addition to providing early clarity, Ofgem, alongside DECC, should ensure that the cash-out proposals do not result in disproportion penalties in the capacity market (as well as in the cash-out arrangements). It is critical that the capacity market strikes an appropriate balance between the potential rewards and penalties to ensure a properly functioning policy intervention.

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 NNH business consumers?

Considering the sums of compensation proposed, we do not consider that the proposals to make payments for involuntary DSR services are of much value. There are likely to be significant costs associated with implementing changes to industry systems and processes, not to mention supplier billing systems. It is not clear, given the lack of detail provided, that these costs have been properly assessed against the potential benefits and therefore it is difficult to establish whether the proposal would achieve its purpose in an efficient and cost-effective way. However, our initial consideration suggests that it's unlikely that payments for involuntary DSR will be particularly frequent and as such the proposed benefits of the proposal are highly likely to be outweighed by the costs of implementation.

In addition, we have a number of questions regarding the practical implementation of this proposal. For example, how will the public be informed of the circumstances under which they can claim and how it differs from other compensation payments? To a domestic or microbusiness customer this may not be easy for them to understand and runs the risk of adding confusion which would be detrimental. It is proposed that there will be a different level of payment per hour for domestic and non-domestic consumers; however it is not clear how this will be established and who will be responsible for its accuracy. It is also unclear how the length of time the customer has been off supply will be verified and who will be responsible for checking eligibility (for example should a landlord of a vacant shop in an affected area be entitled to claim payment?).

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

We do not believe that the costs of STOR should be fundamentally divorced from the pricing of STOR into cash-out. The proposed scarcity values bear no resemblance to the costs of the procured reserve, and as such cannot be considered more cost reflective. Moreover, the additional complexity associated with this proposal (much of which has yet to be designed) and the implementation costs this is likely to entail, suggests that the costs are unlikely to justify the perceived benefits. The potential for imbalance prices to reach VOLL is also a major concern for the reasons provided in answer to Question 3.

However, if Ofgem is determined to implement this proposal, it should be aware that it is likely to take some time to develop. Unless Ofgem develops the details to make the high-level design work in practice, it is likely to take a number of months for a code workgroup to develop the high-level proposal. Therefore Ofgem should not expect an early implementation date. This point also applies to the proposal on voltage control and disconnections.

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.

We do not consider there is a great deal to choose between dual and single pricing. Under both methods the safest position for a party to take is to be balanced. However, we have a slight preference to retain the dual pricing method. This is for two main reasons.

Firstly, while single pricing is superficially simpler than dual pricing, single pricing is more complex for a market participant in terms of deciding what the optimal trading strategy should be. Under dual pricing, a party cannot reasonably expect to do better by going into imbalance than it could by trading in the market. The optimal trading strategy is clear; wherever possible trade out imbalances. However, under single pricing, this clear answer no longer holds. Now a party can be better or worse off by going in to imbalance relative to trading in the market, depending on the system length and the party's direction of imbalance. The best approach now is 'it depends'. This is particularly the case in extreme system stress events. It is unclear what trading strategies parties will adopt and this risks a number of unintended consequences for both energy balancing/cash-out and the capacity mechanism.

Secondly, single pricing will tend to benefit the large vertically integrated companies at the expense of independent parties as they are better placed to offset opposing imbalances. Ofgem believes that wind generators and independent suppliers will tend to be better off under a single price as their imbalances will tend to be both in the same and the opposing direction as the system imbalance. Therefore, opposing imbalances will tend to net off aggravating imbalances in the long run. However, we do not consider the benefit of netting off imbalances in the long run is equivalent to netting off imbalances in the same settlement period (as Vertically Integrated parties can expect to achieve). Netting off imbalances in the long run does not protect parties in short time periods where they may face high imbalance charges due to sustained periods of aggravating imbalances. The credit implications from such scenarios, as mentioned in answer to Question 3, require further analysis also. In addition, new suppliers may be wholly reliant on purchasing at SBP until they have built up the necessary customer base to purchase via the wholesale market. Whilst the Secure and Promote licence condition aims to increase availability of small clip sizes (e.g. 0.5 or 1MW clips rather than the currently available 5 or 10MW) and this will minimise this risk, there will still be a period before a supplier has a customer demand of even 0.5MW.

As such we do not consider that a single cash-out price will benefit small suppliers and wind generators to the degree that Ofgem assumes. The fundamental issue for suppliers, particularly in future, will be that the safe option currently available to them (to go long due to relatively benign SSPs) will begin to disappear as SSPs go negative. While this issue is caused by the changing generation mix rather than the cash-out proposals in themselves, the move to more marginal pricing can only magnify the problem. Moreover, smaller rather than larger suppliers are more exposed to system prices as noted in answer to question 3.

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

No.