Drax Power Limited
Drax Power Station
Selby
North Yorkshire
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Will Fletcher
Project Manager
Competition and Markets Authority
Victoria House,
Southampton Row
London, WC1B 4AD

7 April 2016

Dear Will,

Provisional Decision on Remedies

Drax Power Limited ("Drax") is the operating subsidiary of Drax Group plc and the owner and operator of Drax Power Station in North Yorkshire. The 4,000MW station consists of six separate units, which together produce around 7-8% of UK generation. Two of these units have been converted to run on high density wood pellets (biomass) and a third unit is expected to convert in 2016. At that point, Drax will be a predominantly renewable generator, having completed the largest single site decarbonisation project in the EU.

We welcome this opportunity to comment on the proposed remedies. We are disappointed that the concerns raised in our previous response, particularly those in regards to locational transmission losses, have not been addressed in the latest document. We have set out our concerns on locational transmission losses below, including additional commentary on the latest analysis. Further comments are also provided in relation to the proposed industry codes and CfD FiT remedies.

<u>Locational Adjustments for Transmission Losses</u>

Cost Benefit Analysis (CBA)

Transmission losses make up a very small amount of a customer's overall electricity costs. This change, however, will impose a huge cost on the industry, which will ultimately be borne by consumers.

The modelling, which aims to provide a cost benefit analysis over the first nine years following implementation, indicates a net benefit between +£2.43 and -£0.32 per annum per domestic household. The net benefit in adopting the proposed 0/100% split in allocation to demand/generation versus the current 55/45% split is between +£0.36 and -£0.02 per annum per domestic household. These ranges suggest the benefit of the proposal is very uncertain, is likely to be marginal at best and is extremely sensitive to the modelling assumptions.

With regards to the modelling assumptions, we note:

- **Transmission charges (TNUoS) were used as the main determinant of plant location decisions.** Whilst TNUoS may play a part in new thermal generation investment decisions, there are many other determinants that have an equal or greater influence on build decisions, including available land/access to existing generation sites, planning requirements, access to the network, access to fuel, proximity of workforce, other local infrastructure, etc. These factors are not considered by this analysis.
- **The model fails to recalculate TNUoS charges year-on-year**, meaning that the accuracy of transmission charging signals is ignored after year one.
- **It is clear that locational TNUoS signals do not work effectively today.** Despite a requirement for thermal generation in the north of the country (to provide system stability (ancillary services)), transmission charges continue to rise. This is due to the volume of intermittent renewable capacity connecting in the north, which is indifferent to TNUoS (and losses) charging signals due to the structure of the CfD FiT contract.
- **National Grid must maintain system stability.** If transmission related charges continue to signal the closure of thermal plant located in the north, then National Grid will be forced to enter arrangements to maintain the provision of ancillary services. This does not appear to have been considered in the modelling.

- **The delivery timescales of new renewable and nuclear capacity are questionable.** Given that political support for renewable investment is waning, and the decision on new nuclear deployment has been significantly delayed, it appears that the future of renewables and nuclear new build is uncertain.
- **The assumed wholesale electricity price curve is questionable.** The CMA notes on page 68 that a wholesale electricity price of £70/MWh to £90/MWh is assumed. This seems excessive in comparison to the traded market over winter 2015/16, which has seen the month-ahead baseload price rarely rise above £40/MWh.
- **There appears to be little consideration of IT system changes outside the BSC.** Changing the way in which transmission losses are charged will lead to additional costs to generators (production and trading systems) and suppliers (pricing system changes and quotation production costs).

Overall, the evidence presented by the CMA suggests the uncertain benefit to consumers is likely to be outstripped by the impacts of implementation and/or uncertainty of the assumptions. It would be useful to understand what sensitivity analysis the CMA has performed to test the assumptions.

Going forward, any future amendment to the transmission losses charging regime should be supported by a thorough cost benefit analysis that is open to industry input and consultation. The CBA should demonstrate a clear, certain net benefit to end consumers. Moreover, any order imposed on National Grid to calculate imbalance charges taking into account transmission losses calculated on a locational basis, should ensure all stakeholders have the opportunity to input into the development of the final proposal via an industry working group and consultation.

Competition Impact

Applying losses 100% to generators will exacerbate the existing distortion in competition between GB generators and European imports. Interconnector flows are currently exempt from transmission charges (TNUoS), balancing charges (BSUoS), residual cash-flow reallocation (RCRC) and transmission losses. In addition, interconnector flows enjoy exemptions from the carbon tax (Carbon Price Floor) and certain renewable levies. It does not make sense to further distort the market in favour of European generators – measures are required to level the playing field to avoid a detrimental impact on GB security of supply.

In addition, introducing locational pricing of transmission losses will increase generator uncertainty over their incremental costs. Arguably, the lack of locational pricing of transmission losses results in inefficient dispatch. However, by implementing locational pricing, the resulting uncertainty of incremental costs will result in a new form of inefficient dispatch. In effect, one form of dispatch distortion will be replaced by another. It is not clear which dispatch distortion has a lesser impact on consumers.

There is already strong industry concern over uncertain incremental costs (such as BSUoS), which is leading to increased risk premia in the market. This results in further increased costs to the end consumer. Industry-led work is underway to alleviate these concerns (for example CUSC Modification CMP250). It would appear contradictory, and against the current direction of charging reform, to introduce a new uncertain incremental cost to market arrangements.

Signals to Investors

The recent changes to the Climate Change Levy (CCL) exemption arrangements, in addition to the change in policy on onshore wind and solar, illustrate the damage that can be done to investor confidence at a time when the UK is embarking on a major investment programme to upgrade and decarbonise the electricity system. Care must be taken to protect existing investors when GB market arrangements are modified – investor confidence is already fragile and should not be further eroded.

This concern clearly applies to the potential introduction of locational transmission losses. For existing plant located in GB, this will largely involve a simple one-off transfer in value from plant located in the north of the country to plant located in the south. This transfer is in return for little benefit in terms of improving overall economic efficiency. Should a more robust CBA support the call for change, then there is a good argument to implement it immediately for new plant that has not entered the planning system. However, the losses charging arrangements should be grandfathered for existing plant, or at the very least the arrangements should be implemented over a longer timescale.

Further Charging Reform

Consideration should be given to the timing of transmission charging reform, given similar work is being undertaken elsewhere, for example:

- **National Grid's transmission charging review:** a wide ranging review, including the impact of embedded generation on the transmission system and competitive distortions created by the removal of charges for interconnector flows.
- **Ofgem's review of embedded benefits:** signalled by DECC in March 2016, this review is expected to consider whether the benefits of transmission charge avoidance (including losses) by distribution connected (embedded) generation is right in an age of increased Grid Supply Point (GSP) exports.
- **EU guidance on tariff harmonisation:** work to develop charging principles to be applied across Europe, which is expected to be presented in guidance for Member States on the split of charges between generation and demand side users (amongst other topics).

Forcing reform on this topic without understanding the future charging landscape could mean that the effort and expense of developing a locational transmission losses solution is wasted. The treatment of transmission losses should be a factor in a holistic review of transmission charging reform, with the aim of producing a competitive European market, built on the principle of a level field for all participants.

Losses caused by the System Operator

Consideration must also be given to the impact of National Grid's actions on the system. The System Operator will modify plant dispatch based upon a requirement to stabilise the network, resolve constraints, correct energy imbalances against contracts, etc. These actions are not generator led and, as such, should not be factored into the losses calculation applied to generators. These actions are for the good of all transmission users and should be socialised accordingly.

Contract for Difference (CfD) Process

We support the proposal to publish an impact assessment and consultation prior to allocating (a) technologies to CfD pots and (b) budget between CfD pots. We believe there should be a single CfD budget pot for all technologies or, at least, pots 1 and 3 should be merged to ensure all mature technologies can compete on a level playing field.

To minimise the cost to end consumers, bids in the CfD auction should be compared on a Whole System Costs basis, and not just the levelised cost of energy. That is, bids should consider the costs incurred by the System Operator to procure greater volumes of system balancing services (ancillary services) as a result of connecting a generator that has been allocated a CfD contract.

Analysis performed by NERA and Imperial College[1] has estimated a saving in the region of £2bn if a single biomass conversion project was enabled to compete in the CfD auction on a Whole System Costs basis – a benefit to end consumers that the existing arrangements impede.

Industry Codes

We agree that Ofgem's statutory obligations should be amended to make it clear that competition is a key factor in its deliberations. We would go one step further and state that Ofgem's principle obligation should be to ensure effective competition in the GB electricity and gas markets. The aim should be to deliver a level playing field for all market participants, whether located inside or outside GB, which is clearly in the interests of consumers.

We also agree with proposals to provide clarity on the roles of DECC and Ofgem. Ensuring a consistent approach to policy and regulation, in relation to the GB energy markets, is critical if investor confidence is to be restored.

The proposal to rationalise industry codes is also welcome, provided that the outcome is a simplification of processes to enter and exit the market, rather than adding additional levels of bureaucracy. There must be clear objectives for this work, along with a pathway on how this should be achieved and how success should be defined.

We are, however, concerned over the proposed increase in Ofgem's powers in relation to the industry codes. These are commercial, multi-lateral agreements that underpin the mechanics of the market. The industry code modification process was introduced to allow signatories to raise concerns and develop solutions in conjunction with other market participants.

Over the years, Ofgem has implemented a number of changes to the code arrangements that help smaller parties raise modifications and ensure their interests are protected. A good example is the proposer ownership

[1] Available from: http://www.nera.com/publications/archive/2016/NERA_Imperial_Feb_2016_Renewable_Subsidies_and_Whole_System_Costs_FINAL_160215.html

principle, which ensures the proposer of a modification is able to choose the final solution presented to Ofgem for determination, stopping those with differing perspectives from constraining the solution.

Unfortunately, the proposal to allow the regulator to steer the direction of code modification activities, initiate code modifications without any initial analysis/impact assessment (as required under the Significant Code Review (SCR) route) and take control of modifications (against the proposer ownership principle) undermines the positive reform that has taken place over the last decade.

Ofgem clearly has existing powers to influence and steer the modification of industry codes via the Significant Code Review process. These provisions remain fit for purpose – we believe the pressing question is how the regulator could use these provisions more effectively, rather than introducing further powers that increase regulatory uncertainty and reduce the checks and balances put in place to protect investors. We urge the CMA to rethink its position.

Please do not hesitate to contact me, should you wish to discuss any aspect of our response by phone or in person.

Yours sincerely,

By email

Stuart Cotten
Head of Regulation and Compliance