

DCP 287 Modelling Issues Document

1 March 2018, Reckon LLP

1. Provided the following documents and a cover sheet in response to a request for modelling services received on 8 February 2018.
2. Table 1 lists the items included in their response.

Table 1 Response items

| File name | Description |
|--|--|
| DCP 287 modelling response cover sheet | |
| Blank-EDCM2-dcp287-FCP+r7869 | Blank FCP model implementing DCP 287 |
| Blank-EDCM2-dcp287-LRIC+r7870 | Blank LRIC model implementing DCP 287 |
| DCP 287 EDCM FCP r7869 model document | Documentation for the updated FCP model |
| DCP 287 EDCM LRIC r7870 model document | Documentation for the updated LRIC model |

3. Reckon LLP could not comment on the draft legal text as such, stating that since they do not have any other basis to ascertain what the intended methodology might have been.
4. Reckon stated that there are tensions between the draft legal text sent to them on 8 February 2018 (Attachment C of the modelling specification pack), subsequent versions of the draft legal text included in working group minutes, the statement in the change proposal that “the proposed solution is that the credits should be calculated in the same way as the equivalent demand costs are derived but applied as a credit to eligible embedded generators”, and common sense. Reckon LLP confirmed that they resolved each of these tensions in favour of the version of the draft legal text included in the modelling specification pack of 8 February 2018. Specifically, items (a) to (e) below:

- (a) We have applied the direct, indirect and network rate contribution rates to annuitised figures even though this conflicts with common sense and is different from the way these items are charged to EDCM demand.

I think this is referring to the direct cost, indirect cost and network rates adjustment being proportional to charge one, which represents an annuitised £/kW/year of the cost of reinforcement of an increment of load at that location (at least in the LRIC model – I think this principle broadly holds in the FCP model, albeit calculated based on different assumptions to determine the equivalent reinforcement cost associated with an incremental unit of demand). I think it is a valid point that this is not a logical approach, but I would be keen to keep the link to charge one to ensure that generators with low (or zero) charge one which give little benefit are not unduly rewarded for offsetting these costs. In order to do so I think we would need to convert charge one from £/kVA/year back to £/kVA. This could perhaps be achieved by converting the p/kWh charge one unit rate credit back to a p/kW credit based on the forecast super-red export units. I think any other solution is likely to be quite complicated!

In summary – depending on Working Group discussions, perhaps worth a conversation with Reckon to discuss how this could be more appropriately resolved.

The Working Group discussed AE's response suggesting that Charge One be reverted back to £/kVA rather than £/kVA/Year to ensure that generators with low or zero charge one are not unduly rewarded for offsetting costs. The Working Group agreed that it would be beneficial to discuss this further with Reckon.

- (b) We have included a hard-coded factor of 0.6 for indirect costs even though this figure has no visible means of support and there is no corresponding factor in the calculation of charges for EDCM demand.

This is exactly as requested and is the subject of a consultation question. Think we need to be clear in the consultation why we have been inconsistent with demand, which I think is because of the application to capacity charges rather than unit rates for demand so is treated as a 'cost recovery' for demand rather than our approach for generation which is to give a forward looking signal in respect of these elements. I don't think this argument really holds, but will say so in my consultation response rather than drag out the process of getting the consultation out of the door any further.

In summary – no further action needed I think.

The Working Group agreed with AE's response that no further action is required due to this being in line with the Working Groups view and supported by the consultation responses.

- (c) We have included the “proportion eligible for charge 1 credits” factor in the calculation of transmission exit credits even though it is not included in the most recent version of the working group’s draft legal text and it discriminates against no-F-factor generation exporting to the DNO’s system through an EDCM connection during super-red compared to similar generation exporting through a CDCM connection or embedded within a demand-dominated site.

I think this is an oversight in our legal drafting which Reckon have correctly picked up on. In the consultation as drafted (para 5.15) we say:

“the best solution for this change would be to use the same ‘Transmission Exit Charging Rate’ for generation as is used for demand, but with a credit determined for each EDCM embedded generator which is eligible for charge one credits based on the output of that EDCM embedded generator in the super-red period.”

So our legal text should include a term for proportional eligible for charge one credits in the formula in clause 6.6. In the consultation we go on to say (para 5.16):

“By limiting this to eligible generators it... ensures that where there are generator dominated areas the benefit that they would receive from such a credit is likely to be zero or close to zero.”

I don’t think this is correct – this would be the case if it were proportional to charge one but the factor we have added is not proportional to charge one and so where a generator has zero charge one but has been assigned a non-zero F factor, it will receive the same credit as a generator with non-zero charge one. I’m not sure whether this is as intended by the Working Group – it certainly makes the impact more significant as generators who are eligible for credits but have zero charge one will now receive a credit where previously they would not.

In summary – think this needs a working group discussion to check whether we really intended to make this credit proportional to charge one or not.

The Working Group noted that they have made it explicit that the change is seeking to apply credits to eligible generators and DCP 313 is responsible for setting the eligibility criteria. It was agreed that this should be discussed at the next Working Group meeting. An update to the legal text to make this clear is required.

- (d) We have not applied any loss adjustment factors to the calculation of transmission exit credits even though such factors would seem to make sense and are included in the calculations of the transmission exit elements of EDCM demand charges and CDCM generation credits.

I think this is an oversight by the Working Group. Assuming that units generated flow from a site to downstream demand, we should include an adjustment to reflect that a unit of generation at the boundary of the site avoids not only that unit flowing through the GSP, but also the losses associated which would have been associated with transporting an equivalent unit down to the voltage level of the site. Unfortunately, the legal text for the equivalent adjustment for demand is a little vague (clause 9.2 of schedule 18):

*“Transmission exit charging rate p/kW/day = 100 / DC * NGET charge / (CDCM system maximum load + total EDCM peak time consumption)*

Where

...

Total EDCM peak time consumption (in kW) calculated by multiplying the Maximum Import Capacity of each Connectee by the forecast peak-time kW divided by forecast maximum kVA of that Connectee (adjusted for losses to transmission and, if necessary, for Connectees connected for part of the Charging Year) and aggregating across all EDCM Customer demand.”

I wonder whether we could include a similarly vague term in the formula in clause 6.6 of the revised legal text.

In summary – think this needs a Working Group discussion, but in my view it should be revised.

The Working Group agreed that this may be a valid point and requires further discussion at the next Working Group meeting.

- (e) We have made no attempt at preventing the double payment of transmission exit credits to generators that may support the distribution system through a contract to provide distribution system support in GSP outage scenarios.

This is as expected. We know from our RFI that no such customers exist. But we should perhaps consider revising the legal text to remove the provision of the credit where an agreement is in place, or perhaps modify the DCP 287 legal text to only apply the new exit charge credit where an agreement is not in place (which we know is all at the moment) to ‘future-proof’ the solution.

In summary – Working Group discussion needed on how to treat the potential for a generator to receive credits by agreement with the DNO to export at SGT outage conditions and the new credits

The Working Group discussed the fact that the DCP 287 RFI has shown that bilateral contracts between Generators and DNOs that would allow for Transmission Exit Charge credits do not appear to currently be in place and so it is unlikely that a double credit would be awarded. However, it was also noted that there are two differing requirements, one for providing support during a SGT outage via a contract and the second for the perceived benefit the generator is providing via this change proposal. It was agreed that this should be considered at the next Working Group meeting.

5. As a result of these discussions it was agreed that the next Working Group meeting should be face-to-face and that both AE and Reckon should be in attendance to discuss these matters. ElectraLink took an action to arrange this meeting with Reckon and the DCP 287 Working Group members as a matter of priority in order to keep the change on track to ensure that the change proposal meets the July panel deadline.