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Critique of Ofgem's minded to decision on CMP264 and 265

18 April 2017

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1. Executive Summary

Headlines

This paper sets out why we believe:

- The benefits of implementing CMP264 & 265, and the greatest assessed reduction in the triad demand residual (TDR), presented by Ofgem are greatly overstated
- Notably no account is taken by Ofgem of the impact on increased cost of capital for generation developers, and
- Several increased costs arising from implementation have been omitted from the assessment or are understated.

These cost increases arise in our assessment because:

- embedded generators that remain on the system will seek to replace lost revenues in other markets, increasing the costs in these markets
- more new embedded projects assumed to be available from recent Capacity Market (CM) auctions will not proceed, adversely impacting on security of supply, and
- there will under any scenario be a much less orderly process than that assumed for new CCGTs coming forward filling the capacity gap.

As a result wholesale prices, CM costs and balancing costs will all be significantly higher than Ofgem has estimated.

Overall over the modelled period these factors materially reduce the assessed consumer benefit. There is in addition a number of risks of unintended consequences that Ofgem does not take into account that lead us to conclude that the proposal to implement WACM4 is unsound.

If more realistic assumptions are made, WACM7 emerges as superior to WACM4 in terms of consumer betterment and also gives rise to fewer unintended consequences.

In terms of process:

- This is a rushed code change process that has given little time for participants to fully engage. Ofgem has stated¹ that it will apply a three-month consultation period for matters that have a wide significance and impact, and the CMP264/5 process clearly meets this classification. Ofgem's approach is contradictory to its policy. The deadline has not been extended meaningfully despite impact assessment (IA) corrections being published on 15 March, and
- There has been insufficient time for effective analysis by smaller generators without the benefit of large regulatory teams.

Other key points we make are:

- Capping the TDR at recent levels immediately delivers a large part of the claimed benefits without the risk of the unintended consequences we identify associated with WACM4
- Decisions on enduring rule changes should only be made after conclusion of various other network charging reviews already underway, including the recently announced Targeted Charging Review (TCR). It is possible, indeed likely, that the TCR could result in competing or conflicting changes involving (i) different charges for firm/non-firm connection; (ii) capacity v energy charges; (iii) recovery of fixed/sunk

¹ <https://www.ofgem.gov.uk/consultations/consultations-policy>

costs; (iv) greater locational differentials; and local balancing charges replacing transmission charges over time recognising the contribution embedded generation makes to security of supply

- Future TNUoS levels will also be dependent on Ofgem's price control policies, which should consider how savings to the demand residual could be made, for instance, by decommissioning redundant assets
- Against this background WACM7 offers a much more appropriate and prudent holding option. This would cap the TDR, enable more robust analysis to be conducted and meaningful consultation to take place, and enable interactions with the on-going reviews to be more closely established
- If Ofgem holds course and maintains its decision in favour of WACM4, the solution should be modified to include grandfathering, and
- Ofgem has also published international analysis as part of its proposals to conduct the TCR, but only after the consultation on the minded to decision was underway. This shows unambiguously the difficulty of addressing distortions in fixed/sunk cost recovery in a fair and proportionate way, and demonstrates the need for a managed transition over several years.

Background

The report is the independent analysis of Cornwall. In preparing it, we have been supported by:

- The Association for Decentralised Energy
- Eneco
- Fred Olsen
- Plutus Power
- Reliance Energy
- The Renewable Energy Association
- Renewable Energy Generation
- Renewable Energy Systems
- Rockpool Investments

The Minded to decision

Ofgem published its minded to decision and impact assessment on CMP264 and 265 on 1 March 2017.² It proposes to accept the Working Group Alternative CUSC Modification (WACM) 4, which sets the value of the triad benefit for sub 100MW embedded generation to the locational charge plus the TNUoS Demand Residual (TDR). The TDR will be set at the avoided GSP investment cost (AGIC). This was last valued at £1.62 by National Grid, but will be recalculated prior to implementation (though this value is unlikely to change significantly). WACM4 will also set a floor of zero on the total triad benefit (locational plus the TDR), which will prevent any embedded generation receiving a charge in areas where the locational charge is negative.

The proposed implementation date for WACM4 is 1 April 2018 with a three-year phased implementation. This phasing will mean that full implementation will occur by 1 April 2021. The minded to decision does not contain any provisions for grandfathering as these are seen by Ofgem as introducing a material market distortion.

Impact assessment

The CMP264/5 has been rushed, with Ofgem actively soliciting alternatives. The process has provided little time for assessment of a wide range of complex alternatives that have come forward, and insufficient opportunity for participants to assimilate choices and engage. The CUSC panel is also heavily dominated by parties with transmission connected plant, who clearly have a vested interest in the outcome of the current rule change process, and their voting on the options presented tends to reflect this.

Ofgem has previously stated³ that it will apply a three-month consultation period for matters that have a wide significance and impact, and its approach is contradictory to this policy. The deadline has not been extended meaningfully despite impact assessment (IA) corrections being published on 15 March. In particular there has been insufficient time for effective analysis by smaller generators without the benefit of large regulatory teams but who will nevertheless be materially impacted by the proposed change.

Despite this unsatisfactory process, we have evaluated the Ofgem impact assessment to validate the range of likely costs and benefits of the scenarios set out within the minded to decision. Our conclusion is that several increased costs arising from implementation have been omitted from the assessment or are understated. These cost increases arise in our assessment because:

- embedded generators that remain on the system will seek to replace lost revenues in other markets, which will increase the costs in these markets
- a higher number of new embedded generation projects than assumed by Ofgem will not proceed, adversely impacting on security of supply reducing the assessed benefits, and

² Minded to decision and draft Impact Assessment of industry's proposals (CMP264 and CMP265) to change electricity transmission charging arrangements for Embedded Generators – 1 March 2017

³ <https://www.ofgem.gov.uk/consultations/consultations-policy>

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- there will under any scenario be a much less orderly process than that assumed for new CCGTs coming forward and filling the capacity gap.

As a result wholesale prices, capacity market (CM) costs and balancing costs will all be significantly higher than Ofgem has estimated

Our analysis suggests that the CM will continue to favour smaller, reciprocating generation, which connects at lower voltages, due to its lower capital cost and relative ease of delivery. This preference also reflects the low load factors that CCGT can expect to run at in the future as even more intermittent generation connects to the system. As a consequence, while we expect the CM clearing price to increase, we do not expect it to increase to the same extent as Ofgem. Consequently, we see fewer CCGTs being built. This significantly reduces the assessed net benefits of change, although it is likely that the increased CM costs would be lower than in Ofgem's assessment.

We also believe the market is currently subject to significant policy and regulatory uncertainties. Even were Ofgem's assessment to be broadly right, we don't see new capacity being delivered "at the right time" given the time to develop CCGTs and wider changes in market conditions. In reality, the market already has a very poor record of timely investment in response to market price signals. Under a less than 20:20 vision scenario, CM costs would significantly increase.

The impact of implementing this change on the wholesale market prices will be largely dependent on the merit order and fuel prices at the time, and how these impact the marginal cost of generation. As noted, the Ofgem analysis assumes that CCGTs will emerge as the dominant technology in future capacity markets, but our assessment suggests that this is unlikely to happen given the reasons outline above. Consequently, we forecast that the wholesale price will not reduce as a result of the implementation of the minded to decision. Indeed, we see wholesale prices increasing as embedded generators seek to bid higher to replace lost revenues.⁴

The impact analysis also anticipates a reduction in support payments through the CfD mechanism due to the reduction in wholesale prices. However, our view is that wholesale prices are likely to remain static or increase, potentially resulting in lower levels of support payments. However, an additional cost which does not appear to have been accounted for is that bidders into future CfD auctions will do so with a significant reduction in their triad benefit. This is likely to result in higher auction clearing prices and a corresponding increase in support payments (all other things being equal).

Assessments of wholesale prices are anyway highly speculative given amplified exchange rate risks in the light of the Brexit vote, unknown arrangements for participating in the single market, the amount of interconnection that will go ahead and the terms for trading over them. These risks will of course impact on any modelled scenario. However, we believe that qualitatively these uncertainties will also contribute to delays in investment decisions for transmission connected plant given the considerably larger monies involved.

Furthermore, our analysis suggests that the provision of balancing services costs will increase as flexible plant that provides these services find they are no longer able to also recover TNUoS revenues. This will push up the cost of the smaller embedded stations providing reserve and response services to the system operator, increasing the cost of managing intermittency and causing a rise in balancing (BSUoS) charges. Ofgem believes new CCGT will be able to provide these services cheaper than reciprocating engines, but the current market suggests this is not the case with non-BM resource underbidding larger providers. Ofgem states reduced embedded volumes will allow BSUoS costs to fall as they will be recovered over large volumes; this benefit will be modest at best as peaking volumes to hit triads were never going to be significant.

Without triad revenues to seek peak capacity providers will turn to other similar markets. This refocussing will mean more reliance on imbalance chasing revenues (which is where providers change their output after gate

⁴ In its decision letter on CMP227, Ofgem observed that lower wholesale prices could lead to greater demand for GB generation, actually leading to higher wholesale prices in the short term. There is the first in a number of inconsistencies between the two decisions that both envisaged changes to the basis of allocating transmission charges.

closure as cash-out prices are known with more certainty). Following this introduction of single marginal cash-out pricing in November 2015, this income source became viable and (as cash-out prices can sometimes peak significantly higher than the marginal cost of even diesel generators) then generators missing out on triads will start to trade at the last minute to offset anticipated imbalances. This could make cash-out prices more unstable and the job of the system operator more difficult.

Notably no account is taken by Ofgem of the impact on increased cost of capital for generation developers, which will impose significant new costs in any modelled scenario.

If more realistic assumptions are made, WACM7 emerges as superior to WACM4 in terms of consumer betterment and fewer unintended consequences

Charging reviews

Reducing the TDR to the AGIC is a draconian change to the triad benefit and one which will have an unduly disproportionate impact on one part of the part. It would transform the charging regime from one that seeks to encourage controllable embedded generation to one which could well make it uneconomic for the large bulk of such generators that cannot explore other revenue opportunities because of the contracts they have already entered into.

In six of the National Grid demand charging zones, the triad⁵ benefit is effectively reduced to zero once the floor is applied. In the other eight, it falls to less than £10/kW once the locational charge is considered. In 2020-21 operator revenues for a 20MW flexible gas site at EHV would be impacted adversely by a fall of between 21% and 27% dependent on location.

In reaching the minded to decision, the CMP264 and 265 process has been rushed through under an accelerated timescale. This has prevented the wider implications and the many interactions between the TDR and other parts of the charging regime being taken into consideration. This approach gives rise to a real risk of significant unintended consequences.

There are three major charging reviews ongoing, or about to commence, which will all consider issues relevant to CMP264 and 265. These reviews are:

- Ofgem TCR
- National Grid review of transmission charging arrangements, and
- DNO review of Common Distribution Charging Methodology (CDCM) and EHV Distribution Charging Methodology (EDCM).

Additionally, according to the TCR announcement, further work on forward looking elements of network charges is also now promised as part of the BEIS/Ofgem follow up to the smart, flexible call for energy.

These reviews are all wider than the current CUSC process; given the outmoded nature of the network charging methodologies in GB, these reviews are necessary and timely. They should take account of the interactions between the TDR and other charging issues and should therefore result in an overall, more cost reflective charging regime. However, ***we are concerned that moving to the most adverse available possible solution presented will result in further changes that may require modification at a later date to the minded to decision to accept WACM4.***

In this context, we would highlight comments made by Ofgem in its CMP227 decision letter where it commented on the merits of implementing that proposed change to generator transmission charging arrangements ahead of work already underway within Europe to modernise and harmonise transmission tariff

⁵ This will be achieved by applying Transmission Use of System charges on a gross basis. This means that flows associated with generation will be treated separately to flows associated with demand and different TNUoS rates applied in each case. The TNUoS rate for the generation flows will be a credit based on the locational element plus the AGIC or floored at zero.

structures. “It is not clear what the outcome of this work will be and it is possible that it will not be consistent with [this change proposal]. This could mean that legislation is implemented at the EU level that supersedes [this change proposal]. In our view, this would increase regulatory risk and, ultimately, costs to consumers.”⁶ We do not see any differences to those circumstances and the current ones, and more importantly why Ofgem seems to have diametrically changed its view on the risks and potential impacts of sequential changes.

It is coincidental but relevant that the value transfer, distributional and potential price impacts from CMP227 and CMP264/5 are of a similar magnitude. In contrast, however, Ofgem does not factor in this time the regulatory risks it previously identified.

In our view, the Ofgem consultation gives a very stilted view of the issue and the available benefits of change as it is misleading to consider a reference case based on the current counterfactual. This is because change options exist that assume that the current TDR is capped at recent levels. Instead Ofgem assumes that the TDR increases from £47.30/kW in 2017-18 to £69.60/kW in 2020-21 significantly inflating the assessed benefits of implementing WACM4. Given the material doubt over some of the other identified impacts (some of which we claim are negative), we believe a much more prudent approach is to apply the cap by adopting WACM7, which will deliver a significant part of the consumer savings associated with freezing payments but without the risk of the unintended consequences, especially with regard to capacity closure or project cancellation.

We note that the impact analysis demonstrates a substantial consumer saving can be achieved under the three shortlisted WACMs. However, scenario 2 alternatives all also generate substantial consumer savings in excess of £5bn. Given the charging reviews that are ongoing or, in the case of the TCR, about to commence, we believe that adopting a scenario 2 WACM would still provide benefits to customers while providing confidence to investors that a full and thorough review will take place before a final more evidence-based decision on the TDR is made.

In the event a scenario 2 WACM is selected over the minded to decision, the impact analysis within the Ofgem minded to decision suggests that it will result in an increased cost to consumers. However, this assumes that WACM4 is the enduring solution and that the TCR will not result in any further changes. ***If a scenario 2 WACM were selected, that would have the advantage of acting as a holding position while the reviews take place and prevent investors withdrawing capital from the market, and will reduce the probability of plant who have capacity market contracts not building their plant, supporting a more stable investment environment***⁷.

Locational charges

A fundamental issue that was not addressed in any detail during the CMP264 and 265 process was the cost reflectiveness of the locational (or forward looking) charge. This issue was deemed to be out of scope for the working group. However, we note that the locational charge is a key consideration as the TDR is the resultant charge set to recover the total allowed transmission revenue in any given year after the locational tariff has been set. Consequently, the locational and TDR are intrinsically linked together, and one cannot be considered without the other.

While we recognise that the Investment Cost Related Pricing (ICRP) and locational charge has been reviewed in the past⁸, this has been primarily to determine the cost reflectiveness of the charge from an incremental perspective. The locational element has been developed to determine the differences between the various

⁶ https://www.ofgem.gov.uk/sites/default/files/docs/2015/09/cmp227_d_0.pdf, p3.

⁷ ICIS have recently reported that some planned new power plants that have won capacity market contracts are now for sale - <https://www.icis.com/resources/news/2017/03/31/10093624/-looming-scandal-over-sale-of-uk-capacity-market-new-build/>

⁸ Project Transmit looked at improving the ICRP methodology - [Initial Report of the Technical Working Group September 2011](#)

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locations with GB, but the absolute level has been a secondary consideration. However, the absolute level of the locational charge is much more important once the CMP264 and 265 minded to decision is implemented as it will affect the level of triad benefit differential available to embedded generation. Ofgem seem to see this issue as a low priority and state in their charging review that the locational signals “*remain appropriate at least in the near term, and we note that locational signals for all generation are being considered as part of our work on flexibility and future-focused strategy.*”⁹

We disagree. Until the charging reviews have taken place, we do not feel it is appropriate to move the TDR to the level of the AGIC. Instead, ***WACM7, which sets the TDR at the lowest locational charge, allows the issue of the interaction between the locational charge and the TDR to be resolved without removing a benefit which may need to be re-instated once the review is complete.*** We note that WACM7 was voted as better than the baseline by the CUSC Panel and was voted by one panel member as the preferred option.

Grandfathering

The consideration of grandfathering options within the Ofgem impact assessment shows a significant additional cost where all existing plant receives grandfathering benefits. Where it is only CM and CfD capacity that receives protection, the cost ranges from zero under scenario 1 up to £0.9bn under scenario 3. For scenario 2 WACMs, which is the Cornwall preferred option, the Ofgem assessed cost is £0.47bn.

This additional cost needs to be assessed against various criteria, including:

- The impact on cost of capital for investors
- Likely decisions by existing operators who determine to close early, and
- Short-term cost of replacing any embedded generators with CM contracts not yet built that are cancelled.

Investors value certainty, and bid into previous CM and CfD auctions based on assumptions regarding the future level of the triad benefit. While investors may not have assumed that the forecast level of triads would have been an enduring income, it is also likely that they did not assume that the TDR would be reduced to close to zero. Many investors will view the GB electricity market as a riskier place to invest as a result of implementation of the minded to decision. If no protection is offered to these investors, it is inevitable that a higher cost of capital will be applied when assessing future schemes.

We have assessed the impact of a higher cost of capital would result in a cost of £85m based on a 10-basis point increase, with additional costs of close to a billion pounds over the next 15 years. This is considerably lower than the figure implied by using the 50-basis point premium that Ofgem assumed in its recent RIIO T1 MPR decision¹⁰, where it decided to do nothing because of the impact on investor confidence.¹¹ Either way, this cost is considerably in excess of some of the grandfathering options considered.

The international analysis that Ofgem has published alongside the consultation on the TCR shows the difficulty of addressing distortions in a fair and proportionate way, and demonstrate the need for a managed transition over several years. In four of the examples changes have taken time to scope and implementation paths have been prolonged. In two cases grandfathering has been adopted to augment a smooth transition.

Connection costs

We have highlighted in previous papers submitted to Ofgem on the issue of embedded benefits the important interaction between connection and use of system charges, and their different treatments at transmission and distribution levels. Although Ofgem has implied this is not a significant market, we continue to think it is.

⁹ [Ofgem Targeted Charging Review: a consultation](#) (13 March 2017)

¹⁰ https://www.ofgem.gov.uk/system/files/docs/2016/05/mpr_decision_document_final.pdf

¹¹ It is hard to avoid the impression that Ofgem factors in impacts on investor confidence when it wants to justify not to do something, but ignores it where it wishes to push through change.

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Where a customer pays more up front to connect, then they should expect to pay less for the ongoing use of system. Transmission connected generation currently connect under a super-shallow connections regime, but do not pay high use of system charges due to the European cap on charges for transmission connected generation. At present, the artificially reduced transmission use of system charges for generation gets recovered from demand customers via the triad and therefore becomes a benefit to embedded generation. However, removing the triad benefit without addressing the different connections charging regime introduces a different market distortion between distribution and transmission.

This is another distortion that will need to be resolved as part of the current network charging reviews if the outcomes are to be enduring, and certainly ahead of any unilateral or isolated changes.

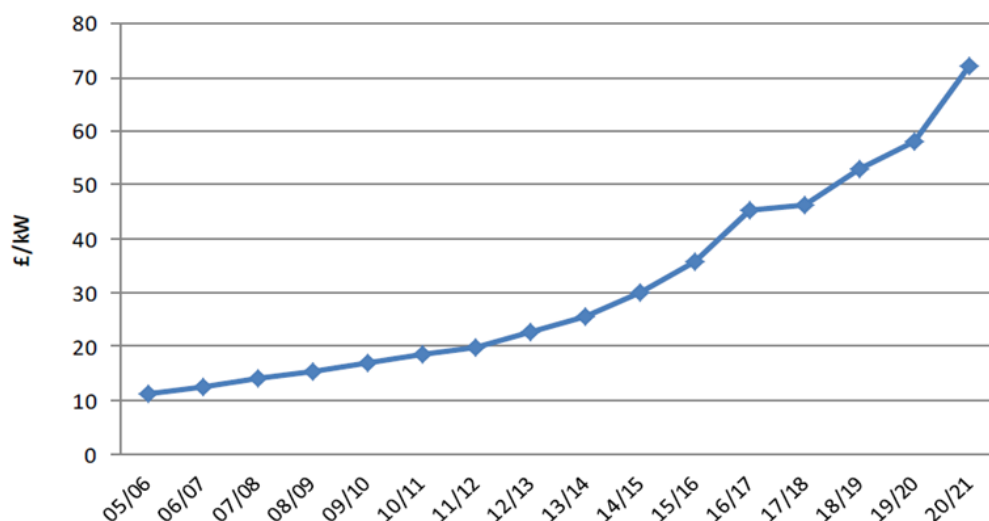
Selecting a scenario 2 WACM, such as WACM7, while reviewing the interaction with connection charging under the charging reviews would allow greater continuity from a charging perspective by retaining some value for the triad benefit and thereby preventing the introduction of a new market distortion in favour of transmission connected generation.

2. Background

Ofgem is reviewing the level of embedded benefits for distribution connected generation amid concerns that these may be providing compensation over and above the benefits that distributed generation bring to the market. In particular, Ofgem is looking to address a concern raised by BEIS (previously DECC), that this could be leading to a distortion in the CM clearing price. Ofgem has been considering the situation since January 2016 and has identified the TDR as a major potential distortion. The TDR has therefore been highlighted as a priority issue by Ofgem, which is looking to two CUSC change modifications (CMP264 and 265) to produce a solution that can be implemented in a timely manner. The TDR has been highlighted as a priority by Ofgem due to the substantial increase in its value over recent years, which is forecast to continue.

The graph below shows how the value of the TDR has increased since 2005.

Figure 1: Trend in TDR from 2005 (£/kW)



2.1 CMP264 and 265

Two modifications, CMP264 and CMP265 were both raised in May 2016 and seek to amend the level of the triad benefits received by embedded generators:

- CUSC Modification Proposal (CMP) 264 was brought forward by Scottish Power. The intent is to set the triad benefit to zero for any new embedded generators that connect after 30 June 2017. Scottish Power justify this change by stating that the current value of the triad benefit is much higher than the costs avoided by the transmission operators as a result of embedded generation and is leading to a distortion in the CM auction. The proposal highlights a report by National Grid that values the avoided cost of embedded generation at £1.62/kW and puts forward that setting the triad benefit to zero would result in a value that is closer to the value assessed by National Grid, and
- CMP265 was brought forward by EDF Energy. The intent is to reduce the triad benefit where an embedded generator has a capacity market contract for the year(s) in which the contract applies by removing the residual element of the triad charge. EDF Energy justify this change proposal by stating that the current level of the triad benefit is not cost reflective and therefore leading to distortions in the capacity market auction.

Both modifications were considered jointly, alongside a series of workgroup alternative CUSC modifications (WACMs). The working groups voted that 12 of these better facilitated CUSC objectives and the workgroup Chair retained a further 29 WACMs that did not receive a majority voted but were considered by the Chair to

better facilitate CUSC charging objectives. In total, there are 23 WACMs for CMP264 and 18 WACMs for CMP265.

The two modifications and various alternatives were submitted to the CUSC Panel in November 2016. The CUSC panel voted on which WACMs are better than the baseline (which is the current arrangements), and each panel member voted on their preferred option. The table at Figure 2 below shows the WACMs that were considered to be better than baseline by the CUSC panel and the number of votes for the preferred option that each one received.

Figure 2: WACMs considered as better than baseline by CUSC panel and votes for preferred option

WACM	Proposer	Description	Estimated triad residual under proposal	Votes - CMP 264	Votes - CMP 265
CMP264	Scottish Power	Triad residual set to zero for all plant commissioned after June 2017	£0.00/kW		
CMP265	EDF Energy	Triad residual set to zero for all plant with a capacity market contract from 2020	£0.00/kW		1
WACM 1	Centrica	Triad residual for embedded generation set at TNUoS generation residual	£2.09/kW		
WACM 2	National Grid	Triad residual for embedded generation set at TNUoS generation residual plus a three year phase in	£2.09/kW		
WACM 3	Uniper	Avoided GSP investment	£1.62/kW	4	3
WACM 4	SSE	Avoided GSP investment plus a three year phase in	£1.62/kW		
WACM 5	SSE	Avoided GSP investment plus TNUoS generation residual plus a three year phase in	£3.71/kW	3	3
WACM 6	National Grid	Residual set at lowest locational charge	£17.24/kW		
WACM 7	National Grid	Residual set at lowest locational charge plus a three year phase in	£17.24/kW	1	1

2.2 Ofgem open letters

Ofgem published its first [open letter](#) on 29 July 2016 outlining its approach to future charging arrangements for embedded generation. At that time, Ofgem said it would not undertake a significant code review, but instead rely on the existing CUSC modifications 264 and 265 to bring forward changes to the triad charging regime in a timely manner. The open letter requested that stakeholders engage in the CUSC modifications and respond directly to Ofgem in response to the open letter. As a result, over 90 potential WACMs were considered by the CMP264 and 265 working groups, and Ofgem received 145 responses to its initial open letter.

It should be noted that, although a large number of WACMs were considered, these revolved around a number of key themes (the value of the TDR, grandfathering, flooring the price to zero and phasing the implementation). It was not possible to consider the possibility of widening the CMP264 and 265 debate to consider other areas of potential market distortions as these were deemed out of scope. This included the possibility of considering the cost reflectiveness of locational charges (discussed later) and amending the triad charge for demand customers. This has effectively restricted the options that Ofgem can choose from,



particularly as all the WACMs suggest a gross charging solution, whereas from a first principle approach the continued use of net charging would arguably be preferable.

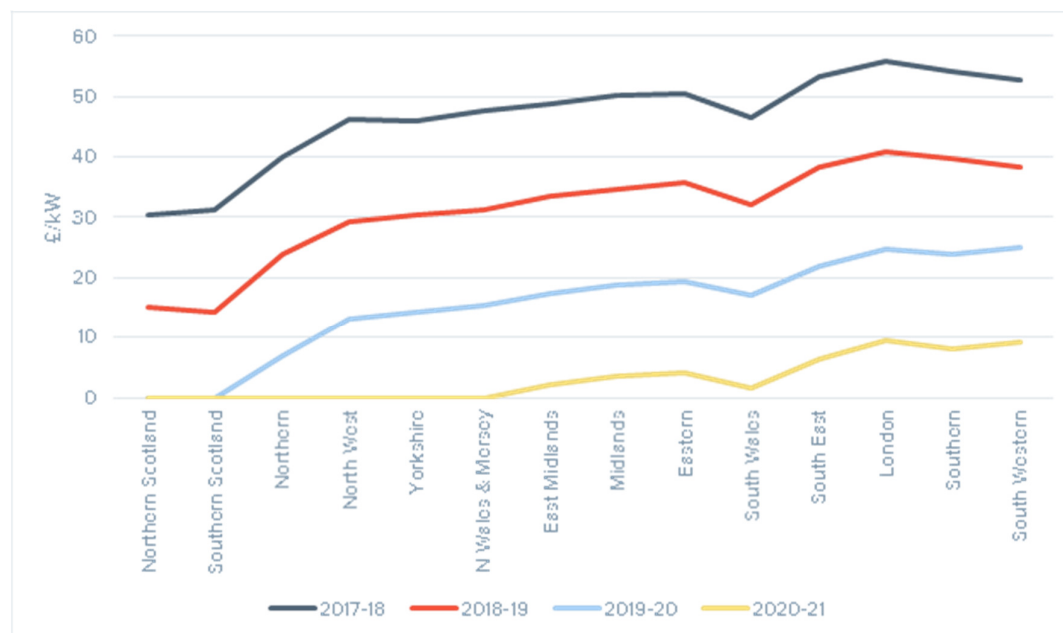
The original open letter references the work by National Grid that suggests the benefit of embedded generation is the locational charge plus the avoided costs of local reinforcement at grid supply points (GSPs) which is valued at between £1/kW and £6/kW. Ofgem also suggested that it would be difficult to justify the costs and/or fairness of grandfathering the current TNUoS arrangements for existing embedded generation given the significant costs and distortions that this would likely cause. No real substantiation is provided by Ofgem in support of these statements.

Ofgem published an [update letter](#) on embedded benefits in December 2016. This reiterated the stance set out in the first letter and gave their view at that time that undertaking a Significant Code Review (SCR) as requested by many market participants would result in considerable delay while triad payments to embedded generators would continue to escalate. The update letter also recommended that embedded generators looking to bid into the T-4 capacity market in December 2016 should assume that the TDR could be as low as the most significant reduction proposed in the code modifications and WACMs under consideration.

2.3 Ofgem minded to decision on CMP264 and 265

Ofgem published a [minded to decision](#) and impact assessment on CMP264 and 265 on 1 March 2017. Ofgem propose to accept WACM4 which sets the value of the TDR to the avoided GSP investment cost. This was last valued at £1.62 by Ofgem, but will be recalculated prior to implementation in 2018 and then reassessed at the start of each price control. Once calculated, the value will be inflated by RPI each year until the value is recalculated at the following price control. WACM4 includes a proposed implementation date of April 2018 with a three-year phased implementation. This will mean that full implementation will occur in 2020-21. The impact of WACM4, including the impact of the phasing in, can be seen in the graph at Figure 3.

Figure 3: Impact of WACM by DNO area (£/kW)



The minded to decision also contains an impact assessment of each of the WACMs that were presented to them. Under this assessment, WACM4 results in £7.2bn of consumer savings and £2.1bn of system savings. The modelling work that underlies this impact assessment is based on a set of assumptions which are reviewed within this paper.

3 Impact Assessment

3.1 Scenario based assessment

The minded to decision for CMP264 and 265 contained an impact analysis of the options under consideration grouped into five scenarios that represented the spread of options. These scenarios are replicated in Figure 4.

Figure 4: Ofgem scenarios used in impact assessment

Scenario	Value of 'x'	Explanation
Scenario 1	£45.33/kW + RPI	This is equal to the current TDR level being frozen
Scenario 2	£20.12/kW + RPI	This consists of the avoided GSP investment cost (£1.62/kW at last estimates) plus £18.50/kW, which is Cornwall's estimate based on their analysis of future transmission capital costs.
Scenario 3	£1.62/kW + RPI	Equal to the most recent estimates of the avoided GSP investment cost (£1.62/kW), as set out in National Grid's informal consultation
Generator residual	Modelled according to National Grid forecasts to 2021 then flat thereafter	Equal to the TNUoS generator residual, with the inverse sign, forecast out to 2021 and then flat thereafter.
Status quo	Modelled according to National Grid's forecasts, rising to £72/kW in 2021, then flat thereafter	The TDR increases in line with National Grid's forecast until 2021 and then remains flat thereafter.

3.2 Comparison of scenarios

The Ofgem minded to decision shortlists 3 WACMs (3, 4 and 5) and presents the impact assessment of these three alternatives within the main document. The appendix includes the results from the five scenarios which represent all the WACMs that Ofgem can choose from. The three shortlisted WACMs demonstrate a range of consumer savings of between £7.2bn and £7.4bn, for the options that exclude grandfathering.

The equivalent impact assessment for scenario 2 is £5.1bn to £5.3bn (phased/ non-phased implementation) and for scenario 1 is £1.8bn (for both phased and non-phased implementation).

Scenario	Grandfathering Options			
	None	A - CM/CfD Capacity	B - Existing capacity	C - Both
Scenario 1	1,811	1,811	1,811	1,811
Scenario 1 phased	1,813	1,813	1,812	1,811
Scenario 2	5,249	4,761	3,803	3,314
Scenario 2 phased	5,051	4,585	3,710	3,244
Generator Residual	7,486	6,755	5,306	4,575
Generator Residual phased	7,404	6,715	5,416	4,728
Scenario 3	7,447	6,599	4,930	4,083
Scenario 3 phased	7,194	6,387	4,862	4,054



3.3 Capacity Market

The modelling work undertaken for Ofgem's impact assessment hinges on the outcome of the CM delivery of new build CCGT, with reductions in Triad income increasing bids from Reciprocating engines, new CCGT can compete. Once this plant comes online it displaces existing CCGT from the merit order, because of their higher efficiency, reducing baseload and peak wholesale power prices and carbon emissions.

Given how reliant the modelling is on the outcome of new build CCGT in the CM, we have assessed how we believe the proposed changes will affect the outcome of the auction and the bids of reciprocating engines.

3.4 CCGT bids

In the first instance, we are concerned about the lack of information on new build CCGT bidding in comparison to the wealth of information presented on reciprocating engines.

What we do know is that the modelling uses the low assumptions from the BEIS generation cost report published in 2016. Our opinion is these costs are too low to be representative of a new build CCGT, for example ESB have claimed Carrington cost €820mn¹²; this is an estimated £800/kW, significantly higher than the £416/kW in real 2015 prices used in the impact assessment.

In addition, no information is presented on the load factor or running regime of these new build plant. While we can expect in their first years of operation they will operate close to baseload as intended, we would expect load factors to drop off in the future because of increased system intermittency. This would lead to these units running in a "Two shift"¹³ pattern, which could adversely impact reliability, availability and therefore profitability.

With the attendant risks over the uncertainty around the future running regime for CCGT, we do not believe the hurdle rates used in the assessment are appropriate. The Impact Assessment assumes a 7.5% hurdle rate for all thermal technologies; 7.5% could be representative of the equity return for a stable utility investor. However, we do not believe the utility companies in GB would be willing or able to invest at these rates, as the balance sheets of many of them have not recovered from previous investments. For merchant developers, which make up most consented CCGT capacity, the investment case is increasingly uncertain and we believe the hurdle rate would need to be above 10%.

3.5 Reciprocating engine bids

We do not agree with the conclusion reciprocating engine bids will be pushed over the level of CCGT bids in the CM auction. In our analysis, we have focused on reciprocating gas engines as diesel engines are less likely to be developed because of DEFRA's proposals to change the MCPD limits, and the ability of reciprocating gas to capture wholesale power prices more efficiently. As with CCGTs, we are concerned the assumptions about cost and returns are too low. We estimate the cost to be closer to £400/kW than the £345/kW used in the analysis. A hurdle rate of 7.5% is used in the Impact Assessment for reciprocating gas engines, which we again believe is unrealistic, and a hurdle rate of 11%-12% is more appropriate.

However, with additional revenues available from remaining embedded benefits and ancillary services as well as the ability to capture higher wholesale prices through flexibly operating within day or after gate closure, we estimate reciprocating engines will be able to make lower bids into the next CM auction despite the proposed change to the TNUoS regime.

¹² <https://www.esb.ie/tns/press-centre/2017/2017/03/13/esb-opens-820m-carrington-power-station-in-manchester>

¹³ Two shifting is where plant come off load overnight on a regular basis, returning to the network over high demand periods in the middle of the day. CCGT in two shift operation can expect a high number of starts, typically 200-250 compared to <15 for baseload operation. This is generally undesirable because of thermal fatigue where components start to degrade because of regular cooling and heating.

3.6 Capacity Market impacts

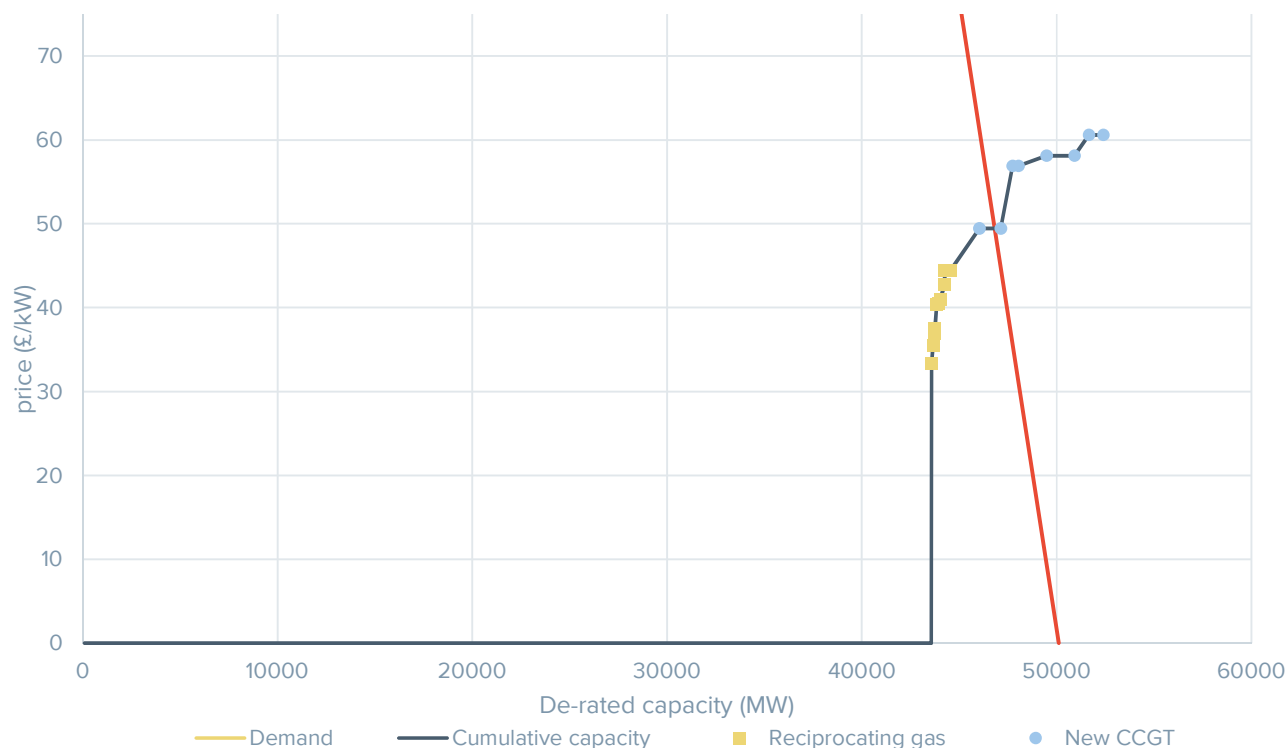
To provide a comparison of the effects of these differences in assumptions, we have presented below our own estimates of the impacts of the changes on the CM merit order.

Our model looks at the expected revenues and costs of a CCGT and reciprocating engine over their lifetimes, considering dispatch and running patterns based on our estimate of future power prices, costs derived from these running patterns as well as ancillary and embedded benefits revenues. A list of inputs which feed into our model can be found in Appendix 1.

In our central and high cost scenario, reciprocating engines underbid new build CCGT in the next CM auction for delivery in 2021-22. This is despite changes to transmission charging to remove the Triad embedded benefit. Before the change reducing the residual to £1.62/kW, we were anticipating reciprocating engines would participate like price takers i.e. they would bid in at low prices and expect to see their prices lifted by other projects clearing higher.

Figure 5 below shows our central estimates where 1GW of reciprocating engines can outcompete even the CCGT in negative TNUoS generation zones. Some CCGT is still bought as we are assuming no participation from coal and limited participation from new build interconnectors. An increase in reciprocating engine, coal or interconnector capacity would therefore reduce the volume of new build CCGT procured in the auction.

Figure 5: Central scenario



3.7 Wholesale market

With a much lower success rate for new build CCGT the benefits, in relation to lower wholesale prices, described in the Ofgem report are less likely to appear. The Impact Assessment states: “*The model dynamically forecasts a greater Volume of new build CCGT. These units are more efficient than existing CCGT units, and therefore set lower peak and baseload wholesale prices.*” Without these CCGT additions, we would not expect these wholesale price effects to materialise.

We do not know from the impact assessment the effect of running in two shift and flexible patterns on the economics of large scale gas plant. In a future where we can expect more intermittency even new build

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CCGT will be running at lower load factors, relying more and more on peak values. Large scale CCGT are not optimised for this pattern of operations, and the plant will need to recover more income through scarcity pricing possibly putting up peak prices. It is not reasonable to expect wholesale power prices, especially peak pricing, to reduce because new CCGT are present on the system.

Gas reciprocating engines, which have lower start-up costs and higher efficiency and reliability when operating flexibly¹⁴, could be a more efficient solution in a low thermal load factor world when it comes to wholesale power pricing. No matter what happens in the CM, it is likely the future we move to has more intermittent generation, and a greater requirement for flexible generation. Figure 6 below demonstrates the requirement for flexibility across a weekday in winter 2022. Stacked up from the bottom are various must run generators (with capacity figures taken from the Scenario 3 phased approach capacity figures published in Ofgem's impact assessment), with new build CCGT at the top in red. While revenues might be attractive over winter, there are still going to be times even that early in the life of the plant that it must two shift.

Figure 6: Comparison of average demand, must run generation and new build CCGT output in winter 2022

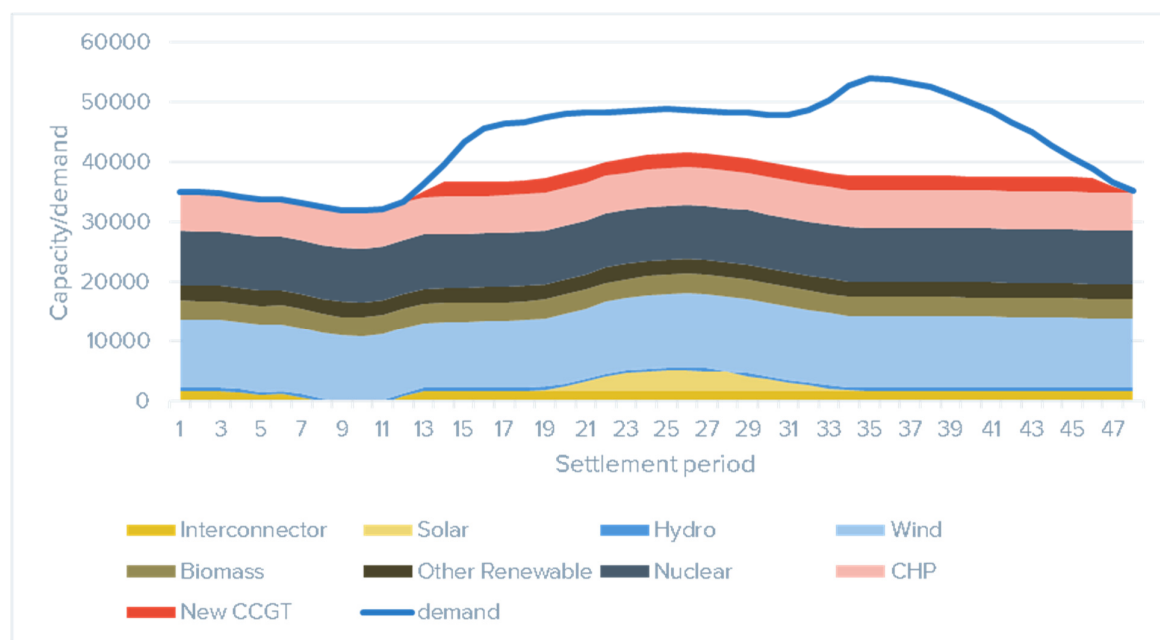
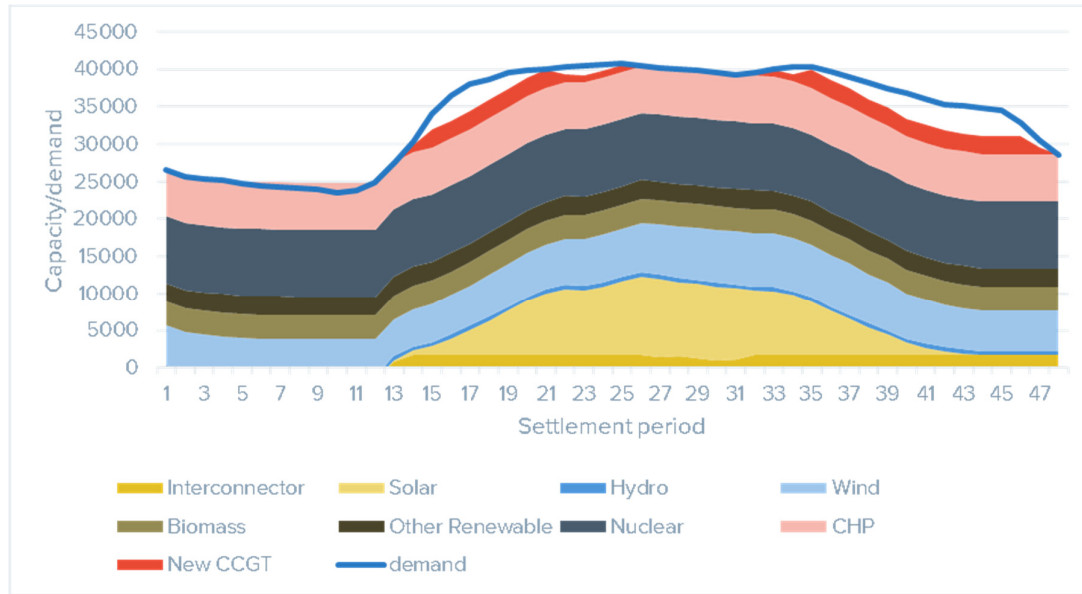


Figure 7 shows a similar picture but for an average summer month, and in this scenario new build CCGT might even have to four shift or run at much lower output than optimal.

In Figure 8 there are three scenarios, (i) a CCGT running at high output – close to 100% of potential load (ii) another CCGT operating at low output, close to 40% of possible load and (iii) a reciprocating engine. The high output CCGT is assumed to complete one start during the day, a hot start, where the plant has only been offline for less than eight hours and the low output CCGT must complete a warm start up where the plant has been offline for between eight and 48 hours. Both plants are then recovering their start-up costs over 16 hours. This is not significantly different from the marginal costs of a reciprocating engine, while the reciprocating engine can offer shorter start up times, higher ramp rates and more reliability when operating flexibly. In addition, adding reciprocating engines will cost less through the CM.

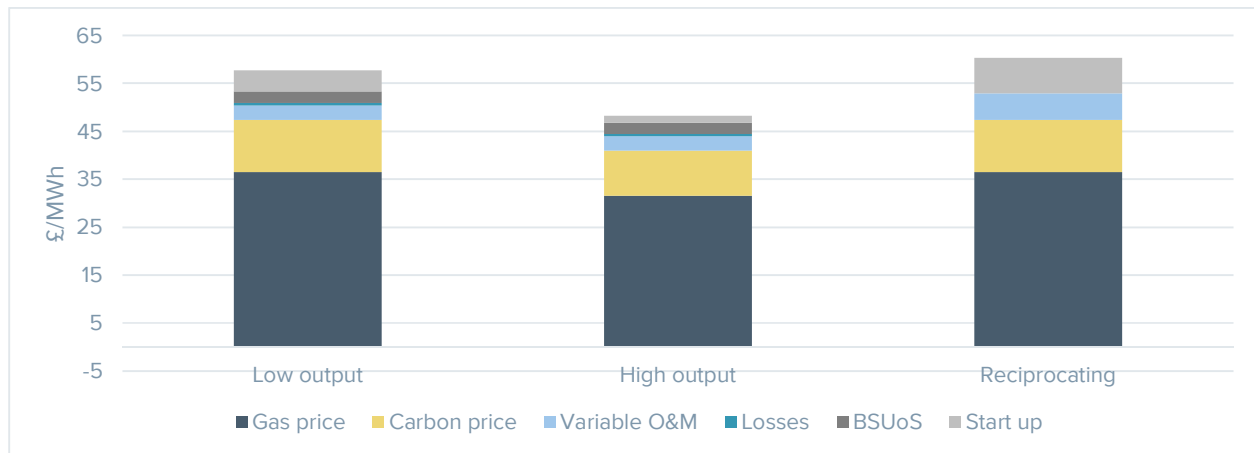
¹⁴ <http://www.wartsila.com/energy/learning-center/technical-comparisons/combustion-engine-vs-gas-turbine-part-load-efficiency-and-flexibility>

Figure 7: Comparison of average demand, must run generation and new build CCGT output in summer 2022



We are sceptical of Ofgem's view of future wholesale prices being lower. With even newer CCGT likely to see lower load factors and requirements for more flexible operation, it seems unlikely an influx of newer CCGT will lower prices as the cost of a CCGT providing flexible power is not significantly below a reciprocating engine. Once EHV GDUoS, transmission losses and BSUoS are taken into account, the reciprocating engine would be incentivised to run ahead of the low output CCGT.

Figure 8: Comparison of CCGT costs



Traditionally utilities have shunned small scale peaking generation as their lower efficiencies meant they were not able to capture as much value from selling wholesale electricity into the market. However, manufacturers have been working on improving the efficiency and emissions from smaller scale gas fired generators. In 2015 GE and MAN announced they had achieved over 50% efficiency rating for their engines¹⁵; this is comparable to the efficiency of large scale OCGT and older CCGT.

There are additional benefits to reciprocating engines over other technologies. A reciprocating engine can be on the grid within a minute and have full power output within five minutes. Compared to a single turbine,

¹⁵ <http://www.powerengineeringint.com/articles/print/volume-23/issue-5/features/the-rise-and-rise-of-gas-engines.html>

multiple engines can shut down individual engines in response to a very volatile power profile, but still run with all the others on full power and efficiency. They can also be dispatched at loads as low as 40% of full load, albeit with a loss of efficiency.

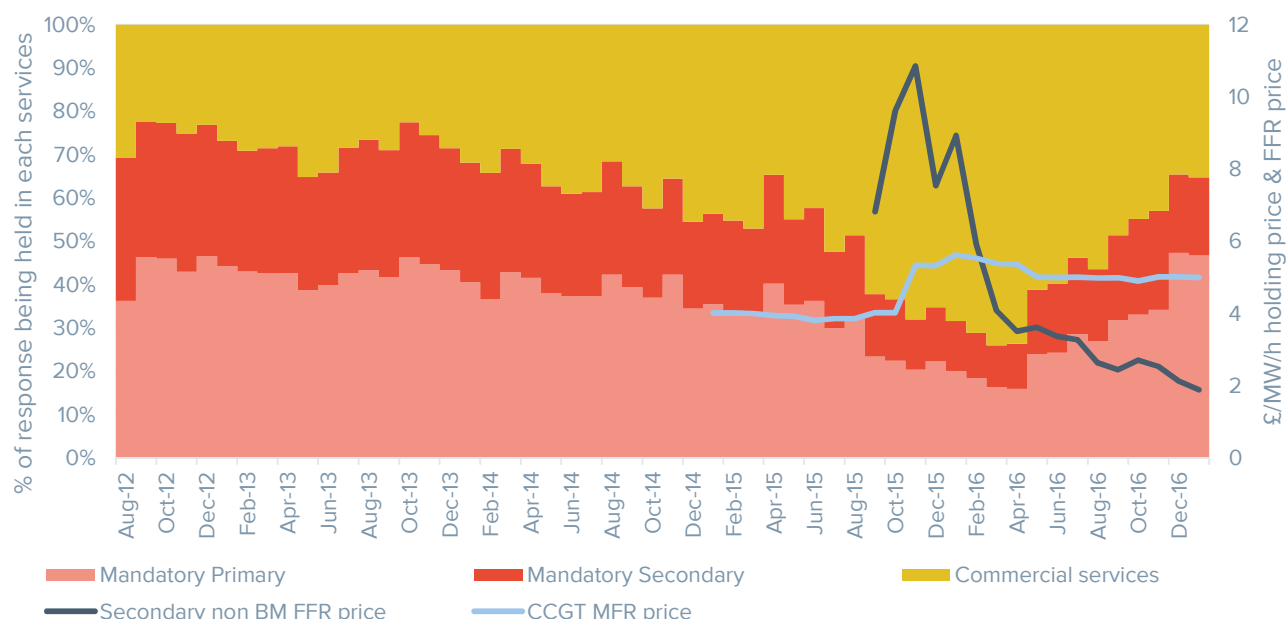
3.8 Balancing services

The case for a saving in balancing services cost is founded on an increase in reserve costs post 2026 as increased volumes of wind drive falling inertia levels, increasing the rate of change of frequency requiring more response and reserve to be held for the larger units connecting to the network. It is assumed this is more expensive in the status quo scenario as reciprocating gas and diesel engines are providing this response rather than a new generation of CCGT.

This again is, in our view, a misreading of the market and the ability of reciprocating engines, which are currently providing reserve and response to the system operator at lower prices than current CCGTs. It is unclear how expensive low load factor new CCGT will be able to compete with reciprocating diesel engines in the very markets they are most suited to.

To demonstrate the cost of reciprocating engines versus large scale CCGTs, we have provided a chart of secondary response prices discovered in FFR against mandatory holding and positioning price for CCGT as well as volumes of MFR and FFR being nominated by the SO. Figure 9 shows that from February 2016 the availability and nomination prices for non BM Secondary FFR providers was below the mandatory holding prices of CCGT for secondary response. In addition this does not include the positioning fees for allowing transmission connected providers to get into a position where they can provide response and therefore mandatory CCGT price would be even more expensive.

Figure 9: Value of secondary response and volumes being held in different services



The other explanation given for reduction in costs is the spreading of BSUoS charging over more MWhs as embedded generation reduces output, as the incentive to hit triads reduces. This modification will only affect the energy output of a small subset of generators with relatively low load factors. Other generators like landfill gas, wind, solar and CHP have other incentives to generate electricity and their embedded output will be unaffected. We conclude, therefore, that the benefit from this change will be minimal.

4 Charging Reviews

There are currently three charging reviews which are either under way or about to commence. Each review covers a wide range of inter-related issues. Although each review is separate, there is also a degree of interaction between the reviews, and it is important that any principles established flow across the reviews to ensure a consistent outcome.

This chapter discusses each review and the scope to identify the degree to which the issues under consideration in the minded to decision interact with the issues identified within the reviews

4.1 Review of distribution charging methodologies

The review of the distribution charging methodologies has been undertaken as two reviews which are now being considered together through a series of workshops. The reviews cover the two charging methodologies that exist at distribution:

- Extra high voltage Distribution Charging Methodology (EDCM) – Methodology to set charges for customers that connect to the distribution network at Extra High Voltage (EHV), and
- Common Distribution Charging Methodology (CDCM) – Methodology to set charges for customers that connect to the distribution network at Low Voltage (LV) and High Voltage (HV).

4.1.1 EDCM review

The EDCM review commenced in 2015, and a [report](#) was submitted to Ofgem in December 2015. In October 2016, Ofgem provided feedback on the report via an open [letter](#). Since then, the review of the EDCM methodology has been merged into the review of the CDCM which has been ongoing since early-2016.

The recommendations of the EDCM review are set out below:

- That ‘Charge 1’, which sets charges based on future reinforcements, is removed and replaced with an alternative method of calculating a unit charge
- A single EDCM methodology should be considered based on Network Use Factors (NUFs) for setting locational charges. This should include an assessment of ways of reducing volatility and also allocating some of the NUF charges to unit rates and whether or not this would be compatible with Time of Use (ToU) or real time charging
- An arrangement similar to that used in CDCM (Time of Day (ToD) or Seasonal Time of Day (SToD)) should be considered to reduce the probability of major shifts of demand between time periods. Moving to unit based charging could create some instability in DNO income recovery, so the spread of the time bands should also be considered
- The allocation of other costs should be reviewed so as to allocate them as closely as possible to the group of customers which benefit from them or historically caused them
- Ways of making available the EDCM models should be investigated so that as far as possible the basis of charges is transparent to customers, although publication of an EDCM model needs to satisfy confidentiality requirements, which has been one of the concerns raised
- Alternatively, a development of a new, all-encompassing methodology, to replace both the EDCM and CDCM should be considered, and
- Consideration should also be given to exploring options for generation credits, as small generators in the CDCM currently receive credits regardless of whether they are intermittent or non-intermittent and embedded generators benefit by a reduction in their demand charges.

These recommendations are wide ranging and, in some cases, require fundamental changes to the principles behind the methodology. The EDCM methodology is relevant to the charges that are levied at transmission as it applies the very largest demand and generation customers that connect to the distribution, some of which are connected close to GSPs. It is likely that some of the EHV customers will have considered both a transmission or a distribution connection before deciding to connect at distribution.

Some of the recommendations interact with the issues considered under CMP264 and 265. These are highlighted below:

- The removal of future reinforcement costs, and recovery of costs based on Network Use Factors (NUFs). This recommendation was brought forward to reflect that the incremental cost element of the EDCM charge is based on a series of assumptions, some of which may not be valid. In particular, the LRIC approach assumes 1% growth per annum, yet in recent years, growth has consistently fallen year on year. The recommendation to move to NUFs means that charges would be levied on a notional path basis (i.e. users would be charged for their share of the assets that they are deemed to be using)
- The move to charge a greater share of costs on a unit basis. This is the opposite of what is currently being proposed under the CDCM review, but reflects the situation that the majority of charges for EHV customers are recovered via capacity based charges, and
- Whether intermittent generators should receive credits. At present, some non-intermittent generators receive credits and no intermittent generators receive credits in the EDCM. This contrasts with the CDCM where all generators receive credits and with the transmission where transmission connected generators incur charges plus a locational charge which may be a credit or a charge.

4.1.2 CDCM review

The CDCM review is currently underway, and is even more wide ranging in scope than the EDCM review. This is because the CDCM has been in existence for longer (since 2010), and also because it has been able to capture some of the more recent issues that have come to light since the EDCM review reported its recommendations. In particular, the debate around the emergence of storage, the proposed changes to the TNUoS Demand Residual under CMP264 and 265 and the move to mandatory half hourly settlement have all led to the wide-ranging nature of the CDCM review.

The CDCM review has been split into two stages. The first stage identified the issues with the current methodology and the potential options for change. This stage was completed in October 2016 and a report was submitted to the Methodologies Issues Group (MIG). Following acceptance of this report by the MIG, a series of workshops were organised to progress the options into recommendations for change. To date, four workshops have been held. These workshops will also progress the EDCM review following the feedback received by Ofgem. It is envisaged that change proposals will be brought forward in mid-2017 to progress the changes to the methodology through DCUSA.

The CDCM review has been split into five areas as follows:

- Type of Costing Model
- Tariff Structures
- Independent Distribution Network Operator (IDNO) Charging Arrangements
- New Products (e.g. Storage), and
- CDCM and EDCM Combined Methodology.

Within each of the areas of work, a large number of sub-options exist. A number of the issues under discussion overlap with the issues under consideration with CMP264 and 265. These include:

- The nature of the costing models – the extent to which an incremental model should be used rather than a cost recovery model
- Tariff structure – whether the format of the existing tariffs are still providing the correct incentives on customers and the tariffs are reflective of the costs driven by customer actions

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Figure 11: Revenue recovery from residual charges

2017-18	Residual/scaling charges	Total network charges
	£million	£million
Transmission generation	32	453
Transmission demand	2,258	2,255
Aggregate distribution charges ¹	1,437	5,235

¹These are the vast majority of distribution network charges. Users connected to a distribution network at the Extra-high voltage level pay an additional c£150m in distribution network charges.

It is clear from the table above that the proportion of charges recovered from the residual element varies substantially by network type and across categories of customers. At transmission demand, the residual equates to over 100% of the total revenue recovered. This compares to distribution where the residual covers approximately 27% and 7% for transmission connected generation.

One of the key questions that will need to be addressed under the TCR is what network costs are potentially avoidable by different users and which are considered as sunk and should fall into the residual. This will require a substantive review of how existing cost elements are being recovered at present and how they should be recovered in the future.

Ofgem's initial view is that all users should make a contribution to common costs, and five options for how residual costs could be recovered have been put forward:

- Option A: a charge linked to net (kWh) consumption
- Option B: a fixed price charge
- Option C: fixed charges set by connected capacity
- Option D: gross kWh consumption, and
- Option E: a hybrid approach.

The scope of the TCR is more wide ranging than it may at first appear. As the residuals can be considered as the balancing item once the cost reflective yardstick charge has been applied, it will be necessary to consider both the calculation of the yardstick charge in addition to the residual.

4.4 Interactions between charging reviews

It is important that the three charging reviews bring forward a consistent approach to the treatment of demand and generation customers across the distribution network (under the CDCM and EDCM) and transmission. This could be achieved through the establishment of common principles that are applied consistently across all network charging. This is clearly not the case at present, with very different principles adopted in the CDCM, EDCM and at transmission level.

One important principle that needs to be established is the extent to which charges are levied on a capacity or demand basis across the networks. Transmission charges are levied on transmission connected generators on a capacity basis, but for demand customers on a unit basis. This creates the anomaly of the embedded generation receiving credits for offsetting a demand charge. The recovery of network revenue primarily through a mix of capacity, unit and fixed charges needs to be explored across networks as a whole for both demand and generation. It may also be appropriate to bring in maximum demand type charges or capacity charges that vary by time of day as considered within the CDCM review.

This paper is not designed to consider the merits of the different approaches to network charging. However, we highlight the strong interaction between the proposed and ongoing work under the reviews and that this is likely to result in some fundamental changes to how network charges are levied in the future. Consequently, it is not clear how the minded to decision will stack up if the reviews result in substantial

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change, which looks likely at present. Put another way, the robustness of the minded to decision will be undermined by Ofgem's own work programme.

The current recovery of the TNUoS demand residual which recovers all the revenue for the transmission companies needs to be considered in this context. Moving to WACM4 almost completely discounts the TDR as an embedded benefit. However, the charging reviews are likely to result in changes to both the magnitude and format of network charging, so removing the TDR as an embedded benefit while the reviews are still ongoing is likely to pre-empt the outcome of the reviews and is likely to result in implementation of the minded to decision needing to be reversed at a later date.

5 Locational Charging

The CMP264 and 265 working groups operated under the terms of reference agreed with the CUSC Panel and progressed under accelerated timescales. One issue that was brought up a number of times during the process, but ruled as out of scope was the cost reflectiveness of the locational charge. A number of working group participants felt that it was impossible to consider the TDR in isolation as it is fundamentally linked to the locational charge.

5.1 Use of an incremental model

The TDR currently recovers all the revenue associated with transmission charges for demand with the locational charge currently recovering a small negative amount in 2017-18. Consequently, changes to the TDR have a substantial knock on impact on the revenue streams for embedded generation. If the locational charges recovered a greater degree of costs, then the TDR would be smaller, so it would seem sensible for both the TDR and locational charge to be reviewed together. The exclusion of an assessment of the locational charge from the CMP264 and 265 working group, placed a restriction that prevented this interaction from being explored.

One of the key concerns expressed by some working group members was that the ICRP model is used to determine an incremental cost signal between areas. This may be appropriate historically when the locational formed the basis for charging before the residual was added. However, dramatically reducing the residual for embedded generation means the locational charge needs to be reassessed to determine whether it is providing the appropriate cost signal on an absolute basis as well as an incremental basis.

An [assessment](#) of the cost reflectiveness of the locational charge was undertaken by Nera and Imperial College in September 2016. This report concluded that:

- The locational element of D-TNUoS charges is only “cost-reflective” in the sense that it emerges from a load flow modelling exercise that seeks to estimate the degree to which costs vary by location. Hence, the locational charge seeks to reflect only the degree of variation in charges across the country, and
- The level of the locational charge – and by implication the level of the demand residual charge – is in no sense cost reflective. In fact, it depends on regulatory decisions on the generation-demand split (currently determined by EU regulations) that have not been justified with reference to cost reflectivity, and on the choice of the reference node within the load flow model.

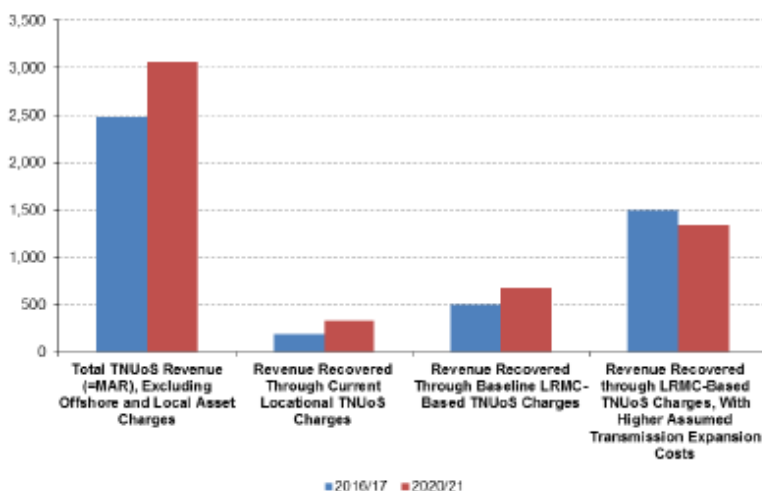
The report goes on to state that part of the issue of the increasing triad benefit lies with the “*wider flaws in the design of the locational charge*” and that “*modelling by Imperial College also suggests that if the locational element of the charge was set closer to LRMC, the amount of revenue the locational charge recovers could increase materially*”.

5.2 Modelling assumptions

Two areas of concern that are raised by the Nera/ Imperial College report are the impact of the reference node and the value of the expansion constants. As with all pricing models, the resultant charges that are produced are reliant on the inputs and assumptions used. The assumptions on the reference node and expansion constants under the status quo are not particularly important as the locational prices that result are only used to produce incremental signals. However, under CMP264 and 265 minded to decision, the absolute level of the locational charge becomes paramount to the future revenue streams of embedded generation.

Figure 12, reproduced from the report shows how much additional revenue could be recovered from locational charges if different assumptions were adopted in the modelling.

Figure 12: Revenue raised from locational charges under alternative transmission pricing methodologies



5.3 Implications for CMP264 and 265

The interaction between the locational price and the TDR is substantial. The locational price is the cost driver for both demand and generation that use the transmission network and consequently, the derivation of the locational charge should form the primary driver of the review, rather than becoming a secondary consideration.

Ofgem has focused on the TDR because it has increased substantially and is forecast to continue to do so in the near future. Clearly, urgent action is needed to the status quo to ensure the consequence of the increasingly non-cost reflective TDR is addressed. However, WACM4 does not provide a solution that takes account of the interaction of the locational and residual charges. Instead it ignores the locational charge and replaces the TDR with the avoided cost of GSP infrastructure.

There is a WACM that was brought forward by National Grid that would both address the issue of the rapidly increasing TDR and also take account of the interaction between the locational and residual charge. WACM6 and 7 propose to set the TDR to the lowest absolute value of the locational charge. WACM6 and 7 are identical except that WACM7 proposes a three year phase in of the change.

Both WACM6 and 7 were voted as better than baseline by the CUSC panel. They also address the fact that the ICRP is producing an incremental cost signal which may not be fit for purpose when applied as an absolute cost signal to embedded generation.

We recommend that WACM6 and 7 would be a more appropriate solution to CMP 264 and 265 that would allow the cost reflectiveness of the locational charge and its interaction with the TDR to be considered holistically within the Ofgem planned targeted charging review.

6 Grandfathering

The minded to decision dismisses options that include grandfathering for two reasons. The first is a concern that grandfathering will introduce a material market distortion between those generators who secure grandfathering rights and those who do not. The second concern is that the impact assessment shows a large reduction in the net benefits to customer where options to implement grandfathering are considered.

6.1 Grandfathering options

A number of WACMs have been submitted to Ofgem that contain grandfathering. The criteria used to identify the generating plants that should be eligible for grandfathering can be grouped as follows:

- Commissioning date – those plant that commissioned prior to an agreed date would be eligible for the grandfathering arrangements, and
- Existing capacity market or CfD contract – those plant that hold a CfD contract or a CM contract from the 2014 or 2015 CM auctions.

Where a WACM adopts a grandfathering approach, they will retain a higher level of benefits than non-grandfathered plant. The value of the TDR in each case is one of the following:

- The TDR set at £45.33/kW until 2033
- The TDR at £34.11/kW for 10 years (WACM23 only), and
- The TDR continues to be applied on a net basis (the status quo).

6.2 Impact of grandfathering

The assessment of the grandfathering options has been undertaken by Ofgem as part of the impact analysis for CMP264 and 265. Figure 13 is a summary of the additional cost of each of the grandfathering options considered:

Figure 13: Impact of grandfathering options on consumer benefits (£m)

Scenario	CM/CfD Capacity	Existing capacity	C - Both
Scenario 1	0	0	0
Scenario 1 - phased	0	-1	-2
Scenario 2	-488	-1,446	-1,935
Scenario 2 - phased	-466	-1,341	-1,807
Generator Residual	-731	-2,180	-2,911
Generator Residual – phased	-689	-1,988	-2,676
Scenario 3	-848	-2,517	-3,364
Scenario 3 - phased	-807	-2,332	-3,140

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Across the scenarios, the additional cost of grandfathering ranges from £488mn up to £3,364mn. The additional cost is much higher when all existing capacity gains grandfathering rights (£1.3bn - £2.3bn) than when it is applied only to generators who hold a capacity market or CfD contract (£466bn - £848mn).

The cost of the grandfathering arrangements appears high, but this additional cost needs to be assessed against a number of criteria including:

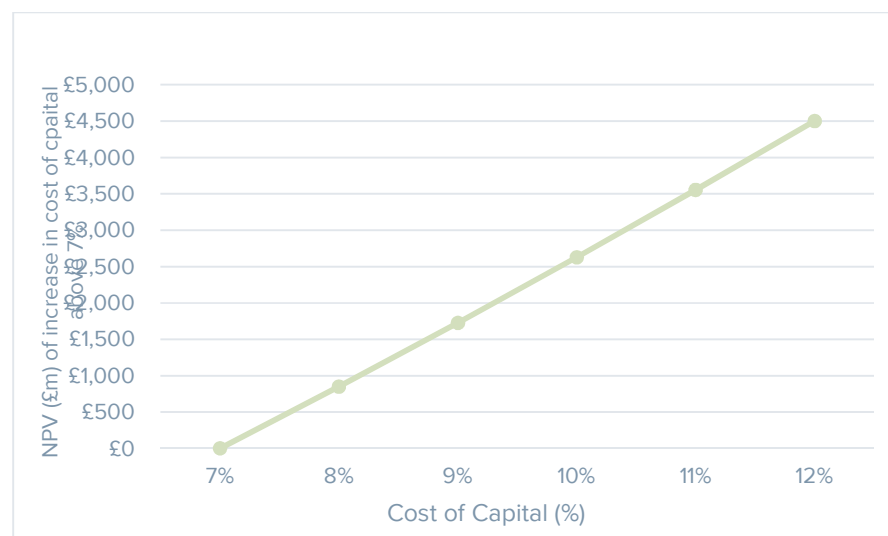
- The impact on cost of capital for investors
- Likely decisions by existing operators who determine to close early, and
- Short-term cost of replacing any embedded generators with CM contracts not yet built that are withdrawn.¹⁶

6.3 Cost of capital

To determine the impact of changes in the cost of capital, we have assessed the impact of changes in the cost of capital relative to a baseline level. The assessment has been undertaken across the 15 year period to align with the Ofgem impact assessment.

In total, the Ofgem impact assessment secures between 25.2GW and 26.7GW of new generating capacity across the scenarios considered. Assuming an average of 26GW of new capacity at an average capex of £320/kW gives an average expenditure of £8.3bn over the period. The baseline cost of capital chosen for the analysis is 7% and the impact of this level increasing has been determined as the net present value of the increase in costs that result. The relationship between the percentage cost of capital and the NPV of the impact can be seen in the graph below:

Figure 14: Impact of variances from a 7% cost of capital



The impact of a 1% increase in the cost of capital is significant at £849mn. If the cost of capital continues to rise, the impact grows correspondingly higher. Although the cost of capital is an unknown, one of the key drivers is the level of perceived risk and CMP264 and 265 if implemented will introduce a new risk into the market. This risk is compounded by the fact that existing generators are not offered any protection against the substantial change to the regulatory regime that has emerged since their investment was first made.

¹⁶ The capacity shortfall could be significant. KPMG has estimated that as much as 2.1GW based on the 2015 T-4 auction alone could be at risk. <https://ukpowerreserve.com/report/uk-power-reserve-commissions-report-effects-changes-embedded-benefits-uk-energy-trilemma-2/>

The minded to decision recognises that there may be an increase in the cost of capital but that this is expected to be outweighed by the consumer benefits and the improvement in competition:

“7.26. There have been suggestions that change to the current regime will bring about increases in borrowing costs, which could outweigh the benefits of change. We expect that any increase in the cost-of-capital for smaller generation would be outweighed, not just by the consumer benefits, but by the improvement in competition. Larger generation will find itself in an improved operating environment, and without grandfathering, new smaller EG will compete with existing operators on a level playing field.”

Our analysis suggests that the impact of an increase in the cost of capital could be larger than Ofgem expects. In addition, the perceived benefit in improved competition cannot be assessed as the change under CMP264 and 265 only amends the value of TDR. As mentioned elsewhere in this document, the TDR is inter-related to a large number of market issues. It is likely that changing the value of the TDR will have an impact on a number of areas which could result in new market distortions arising. It is therefore not clear whether moving to the minded to decision will result in improved competition until a more holistic review, such as proposed under the TCR, has been completed.

6.4 Replacement capacity

The capacity market is designed to secure capacity to increase system security at the lowest cost. The substantial change to the TDR is likely to result in some peaking plant that won contracts in the previous capacity market auctions becoming unviable and withdrawing their capacity. If this happened, the capacity will need to be replaced in early auctions. This can be done through securing additional existing capacity that was previously unsuccessful in the t-4 auction or bring forward plant that can be built very quickly.

The annual cost of securing this replacement capacity is difficult to predict. Below is a matrix that shows the annual cost that would result from the requirement to replace between one and three GW of capacity at a range of strike prices:

Figure 15: Annual cost of replacement capacity (£m) secured via capacity market

Clearing Price (£/kW)	Additional Capacity Procured (MW)		
	1,000MW	2,000MW	3,000MW
5	£5mn	£10mn	£15mn
10	£10mn	£20mn	£30mn
15	£15mn	£30mn	£45mn
20	£20mn	£40mn	£60mn
25	£25mn	£50mn	£75mn
30	£30mn	£60mn	£90mn
35	£35mn	£70mn	£105mn
40	£40mn	£80mn	£120mn

The additional capacity would need to be secured each year, until the next T-4 auction takes effect. The next T-4 auction will take place in late 2017 and apply for the year 2021-22. This means the additional capacity will need to be secured under three T-1 auctions. Assuming a clearing price of between £20/kW and £30/kW, we estimate the impact will be in the region of £60mn to £270mn.

6.5 Summary

Investors like certainty, and they bid into previous capacity market and CfD auctions based on assumptions regarding the future level of the triad benefit. While investors may not have assumed that the full level of triads would be an enduring income, it is also likely that they did not assume that the TDR would be reduced to close to zero, especially for the first two T-4 auctions. Many investors will view the GB electricity market as a riskier place to invest as a result of implementation of the minded to decision. If no protection is offered to these investors, it is inevitable that a higher cost of capital will be applied when assessing future schemes.

We have assessed the impact of a higher cost of capital would result in a cost of £849m based on a 1% increase in the cost of capital for £8.2bn of capital investment over the next 15 years. In addition, the cost of securing additional capacity if plant is withdrawn from the market is estimated to range from £60mn to £270mn. This compares with a range of costs of providing grandfathering for those plant with a CM or CfD contract of between £466mn and £848mn.

Cornwall has spoken to a number of small embedded generators who are considering their position as a result of the proposed minded to decision, including whether they should withdraw capacity. In a number of cases this decision is being forced upon them by investors who are unwilling to commit further funds given the fundamental change in the marketplace to which they had originally invested. We believe there is a strong case for amending the minded to decision if Ofgem continues with it to include grandfathering, and Ofgem should reassess the benefits of grandfathering if it proceeds with WACM4.

7 Connections Policy

As discussed in chapters 4 and 5, the TDR is not a standalone issue that should be considered in isolation. The National Grid review of transmission charging arrangements has clearly highlighted the degree to which the electricity market is multi-dimensional. Addressing one market distortion, without evaluating the market as a whole, results in the potential creation of market distortions elsewhere and without assessing the impact of these new distortions it is impossible to tell whether GB consumers benefit overall from CMP264 and 265.

One area that merits further attention is the difference in the connections policy between distribution and transmission. This is important as when users connect to the network, the costs associated with the connection are either recovered upfront through connection charges or recovered on an ongoing basis through Use of System charges. The overriding principle is that a site that pays more upfront, should pay less ongoing charges as a greater contribution to the network assets has been made. Conversely, where the upfront contribution is low, the site should incur higher ongoing Use of System (UoS) charges.

The issues associated with customer contributions is twofold:

- Firstly, transmission connection charges are considered shallow. This means that the connectee only makes a small contribution to the cost of connecting to the transmission network. At distribution, connection costs are deeper and connectees are required to make a greater upfront contribution
- Secondly, the cap on transmission charges imposed by European legislation means that the low contribution made by connectees under the shallow transmission connection policy cannot be recovered through higher UoS charges and is instead recovered from demand customers.

7.1 Distribution vs. transmission connection costs

Although it is generally accepted that connection costs are higher at distribution than transmission, there has been little evidence to support this view as connection costs are site specific and therefore difficult to compare on a like for like basis. To quantify the difference and estimate the value, Cornwall has assessed two source of information.

7.1.1 Transmission connection costs

To assess the typical value of connecting to the transmission network, tables 14 and 44 from the National Grid [five-year TNUoS tariff forecasts](#) have been used. Table 14 from that document contains information relating to the level of connection payments for National Grid, Scottish Power and Scottish Hydro. Table 44 contains the Contracted TEC in each year. To determine the average connection cost on a unit basis, the connection payment in each year has been divided by the change in TEC after excluding offshore windfarms and interconnectors. The removal of this capacity is to ensure a prudent approach is adopted and to ensure the analysis does not underestimate the connection costs.

The result of this analysis is summarised in Figure 16.

Figure 16: Average connection costs at transmission

	2017/18	2018/19	2019/20	2020/21	2021/22
Total Connection Cost (£m)	58	72	72	74	74
Change in TEC (excluding I/C & offshore wind)		5,004	7,922	10,597	4,033
£/kW		14.37	9.13	6.95	18.28

7.1.2 Distribution connection costs

To assess the level of connection costs at distribution, we have used the CCCM to create a comparative value. The CCCM is a statement that all DNOs are required to publish and provides estimates regarding the level of costs a customer can expect to incur when connecting to the distribution network.

The CCCM statement is contained with Schedule 22 of the Distribution, Connection and Use of System Agreement (DCUSA). Within the CCCM are worked examples that show the cost of connecting different customer types (including demand and generation) to the distribution network. This includes a breakdown of the cost and how it is apportioned between the end customer and the DNO.

Seven of the worked examples relate to connecting generation under a range of scenarios. In each case the connection payment due from the customer has been divided by the generation capacity to determine the unit cost in £/kW for comparative purposes.

The results are shown at Figure 17.

Figure 17: Typical connection costs for generation at distribution

	Example 5	Example 7a	Example 7b	Example 11	Example 14	Example 15	Example 16
Customer contribution	142,542	227,587	628,117	332,000	11,375	111,666	76,000
Capacity of DG connected	3,000	3,000	3,000	5,000	25	2,000	250
£/kW	47.51	75.86	209.37	66.40	455.00	55.83	304.00

7.1.3 Connection cost comparison

The analysis undertaken shows a substantial difference in the costs to connect at distribution and transmission. The average transmission connection cost is £12.2/kW compared to an average cost at distribution of £173.4/kW. When the values in excess of £100/kW are excluded from the distribution connection costs, the average is still significantly higher at £61.4/kW, which is five times higher than at transmission.

While this analysis is not exhaustive, it provides a useful indication of the size of the discrepancy that exists and the potential market distortion that may result. It should also be noted that to avoid high connection charges at distribution and to enable quicker connections, many generators are connecting under non-firm connections. This type of connection means the generator does not have guaranteed access rights to the network and the export may be curtailed under certain circumstances.

7.2 Relevance for CMP264 and 265

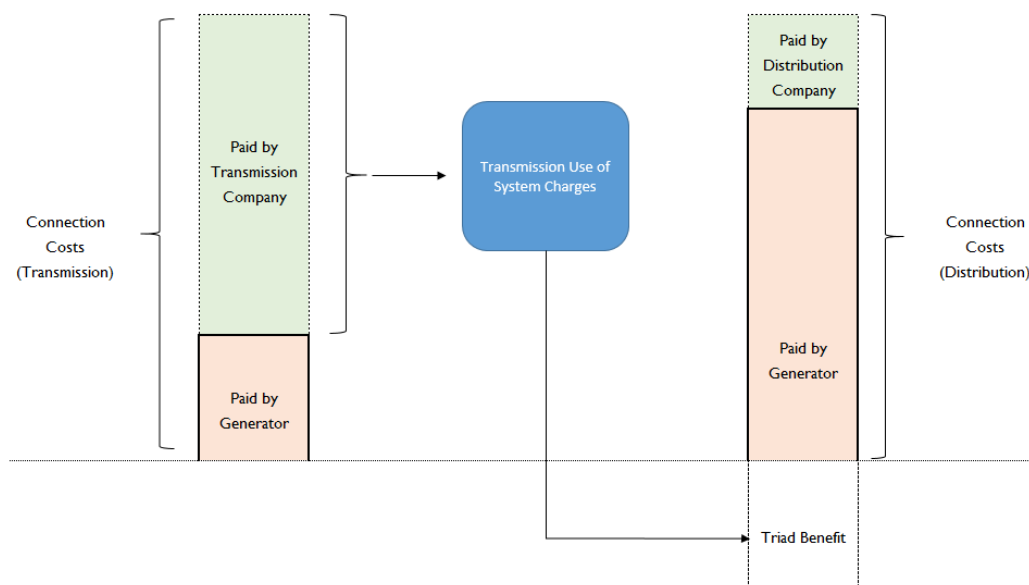
All things being equal, there should not be a material market distortion resulting from different connection policies. This is because connection costs are either recovered upfront or flow into the use of system charge. However, at transmission, the majority of the use of system charge is recovered from demand customers which means that the cost of connecting a generator to the transmission network is subsidised by demand customers.

The issue of connection policy is closely linked to that under review by CMP264 and 265. A deeper connection policy at transmission would mean that transmission connected generators pay more up-front, similar to the approach at distribution, and the TDR would be lower as a result. We have identified a number of issues that need to be assessed before substantive changes to the triad benefit for embedded generators are implemented:

- The level of locational charges – The level of locational charges (as discussed earlier in this report) are cost reflective when deriving the difference in costs between regions, but not cost reflective in absolute terms. Consequently, this means that the cost reflectiveness of the locational charge needs to be assessed for both embedded generation AND transmission connected generation
- The generation residual – As the locational charge is not considered cost reflective in absolute terms, a residual element is applied. A default value of 27% to generation is applied which is further constrained by the EU cap on transmission charges. Both of these methods of setting the residuals are artificial constraints that result in charges for transmission connected generation that are unlikely to be cost reflective.

The link between the level of charges for transmission connected generation and the TDR, means that under the current arrangements, the two market distortions that currently exist offset each other to a certain extent. This is because when the charge to transmission connected generation is constrained, the additional cost that should be recovered is passed into the TDR. The TDR is therefore higher than it should be and becomes a credit for embedded generation. Figure 18 below shows how these two effects offset each other under the status quo.

Figure 18: Offsetting market distortions



7.3 Summary

Although the level of the TDR is clearly a concern that need to be addressed quickly, it cannot be addressed in isolation. The TDR is intrinsically linked to both the cost reflectivity of the locational charge (in absolute terms) and the different connection policies between distribution and transmission. The minded to decision has proposed WACM4, which effectively removes the TDR as an embedded benefit by setting it to a minimal value. By reducing it to such a low level the offsetting market distortions that currently exist, become substantive issues in their own right.

Our assessment of the different connections policy that exist at transmission and distribution suggests that if a more moderate WACM was adopted, the consequential market distortions that would be created would be mitigated to a large extent. This would enable a more thorough review to take place that takes full account of the inter-related issues as planned under the targeted charging review and the National Grid review of transmission charging arrangements.

Appendix 1 – Cornwall Modelling assumptions

Several assumptions and models were used to create the capacity market clearing prices highlighted in section 3. This appendix sets out the methodology used to produce them.

To calculate the bid prices for a range of different technologies we created sample business models for both CCGT's and reciprocating gas engines. These models take capital costs, operating costs, forecasts running patterns and expected revenues and try to calculate what Capacity Market income would be required over 15 years to meet a target hurdle rate. Many of the most important variable are highlighted in the table below.

Figure 19: Key variables in Capacity Market price modelling

Scenario	Central	Central	High	High	Low	Low
Technology	CCGT	Gas reciprocating	CCGT	Gas reciprocating	CCGT	Gas reciprocating
Capital cost (£/kW)	535	362	600	412	416	345
Hurdle rate (%)	10.0%	11.8%	11.8%	12.5%	7.8%	10.0%
Fixed annual O&M costs (£/MW/yr)	16.5	8.4	16.5	8.4	16.5	8.4
Variable O&M costs (£/MWh)	3	5.5	3	5.5	3	5.5
Load factor	Based on the marginal cost of the station.	Based on the marginal cost of the station and embedded benefits.	Based on the marginal cost of the station.	Based on the marginal cost of the station and embedded benefits.	Based on the marginal cost of the station.	Based on the marginal cost of the station and embedded benefits.
Connection costs	Super shallow charges recovered through locational TNUoS over lifetime of plant, can be a credit in certain locations/years.	Shallow, with up-front costs and ongoing charges.	Super shallow charges recovered through locational TNUoS over lifetime of plant, can be a credit in certain locations/years.	Shallow, with up-front costs and ongoing charges.	Super shallow charges recovered through locational TNUoS over lifetime of plant, can be a credit in certain locations/years.	Shallow, with up-front costs and ongoing charges.
Lifetime (yr)	30	20	30	20	30	20

The wholesale power prices used in this modelling were calculated using the Cornwall Power Price Model, which generates half hourly power prices based on randomised samples for demand and generation availability as Wholesale power prices are highly dependent on the levels of available generation and the demand requirement for any given period of time. Given the anticipated wider variation in generation availability, particularly wind and solar, there will be greater volatility in wholesale power prices.

These prices are then fed into a separate dispatch model which takes wholesale power price, embedded benefit and fuel price data compares it to the dynamic data from the generator being modelled and

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determines a running pattern to maximise profits. This data provides estimated load factors and captured power prices for use in the Capacity Market bid model.

Figure 20: Load factor by technology

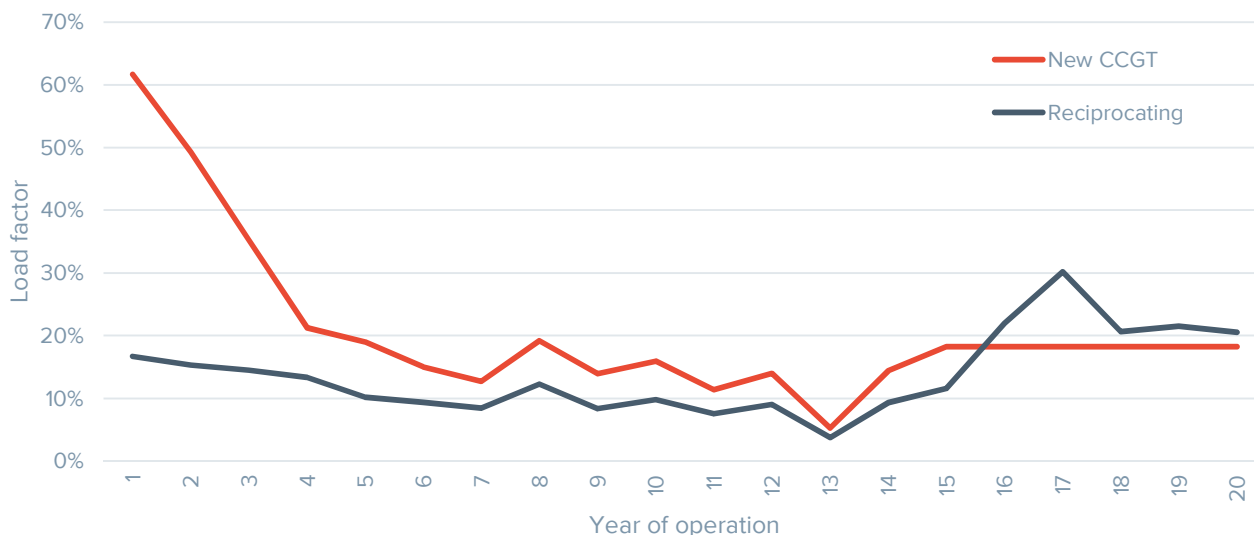
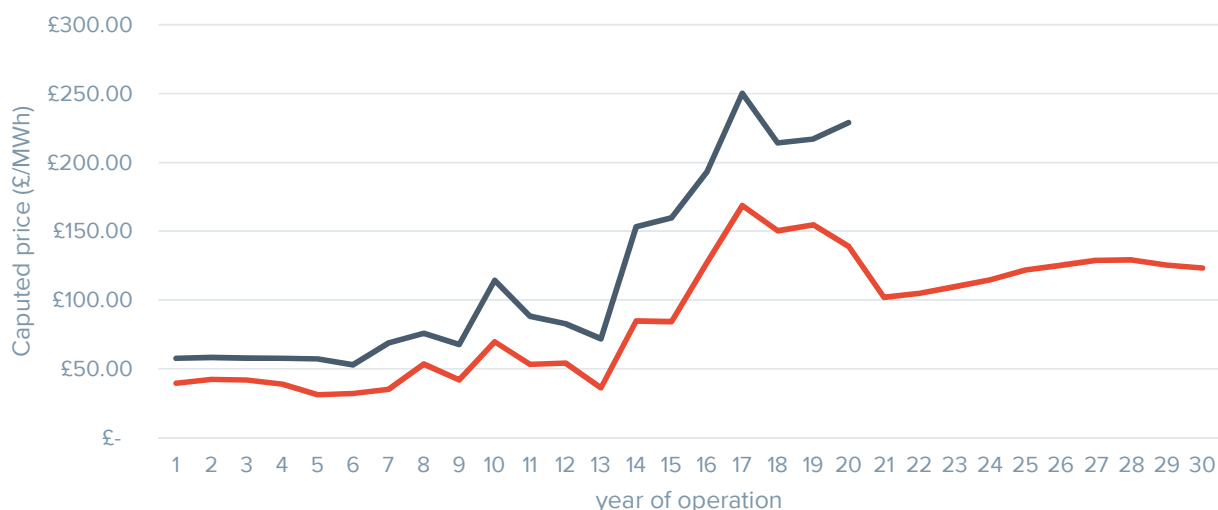


Figure 21: Captured wholesale power price by technology



The gas prices which were used to assess the marginal cost of production for both technologies were the latest BEIS fossil Fuel price assumption¹⁷ published in November 2016. A 2p/therm gas transportation charge was added onto the cost for the reciprocating engine. The carbon prices used were based on the reference case from the BEIS Energy and Emissions projections annex M¹⁸.

These calculations were performed for a range of different stations to provide a range of possible bids from different stations. For CCGT all participants in the T-4 auction in 2016 which did not win a contract were modelled and 14 different reciprocating gas engines were modelled. 1GW of reciprocating as was assumed to take part in the theoretical auction and the capacity was distributed according to historic geographical

¹⁷ <https://www.gov.uk/government/publications/fossil-fuel-price-assumptions-2016>

¹⁸ <https://www.gov.uk/government/publications/updated-energy-and-emissions-projections-2016>

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distribution. To build the capacity market supply curve all existing generation which previously won a contract were assumed to bid in at £0/kW.

The results of the high and low cost scenarios for New Build CCGT and reciprocating gas engines are presented here, only in the low price scenario are new build CCGT ahead of reciprocating engines in their capacity market bids, however we consider a capital cost for a CCGT below £500/kW to be quite unlikely given the prices historically seen in GB.

Figure 22: Low capital cost scenario Capacity Market bids

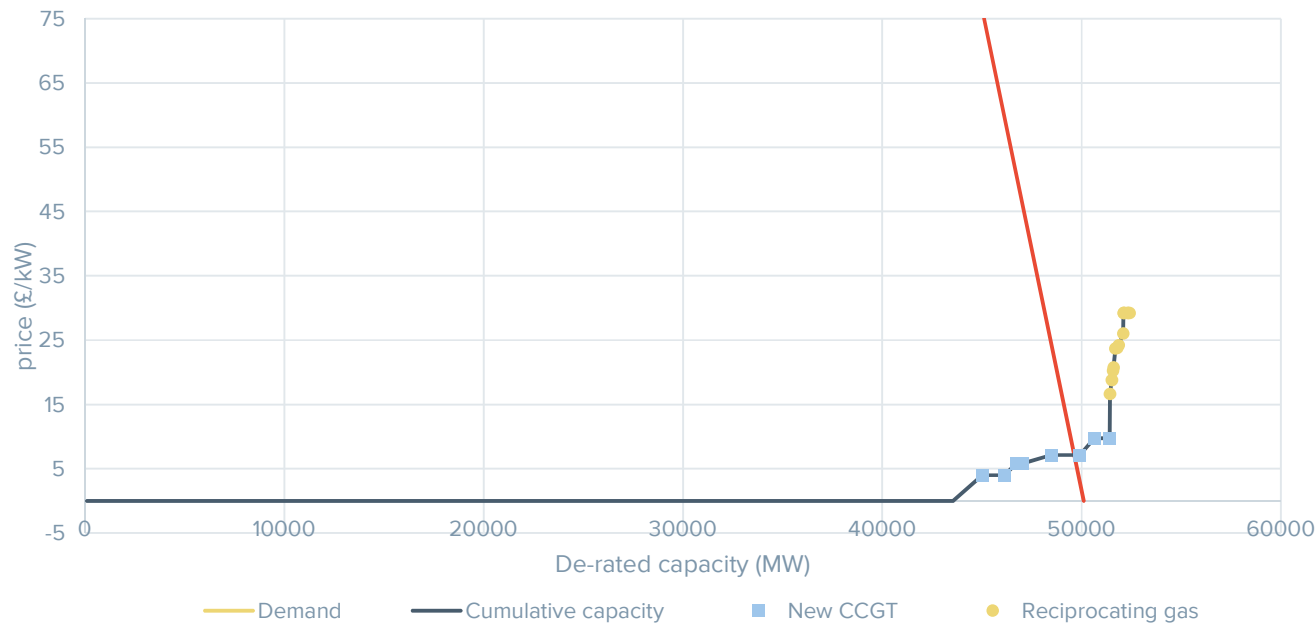


Figure 23: High capital cost scenario Capacity Market bids

