

Response to DESNZ Call for Evidence into Capacity Market Consumer-led Flexibility (February 2025)

About Energy UK

Energy UK is the trade association for the energy industry with over 100 members – from established FTSE 100 companies right through to new, growing suppliers, generators and service providers across energy, transport, heat and technology. Our members deliver nearly 80% of the UK's power generation and over 95% of the energy supply for 28 million UK homes as well as businesses. The sector invests £13bn annually and delivers nearly £30bn in gross value - on top of the nearly £100bn in economic activity through its supply chain and interaction with other sectors. The energy industry is key to delivering growth and plans to invest £100bn over the course of this decade in new energy sources. The energy sector supports 700,000 jobs in every corner of the country. Energy UK plays a key role in ensuring we attract and retain a diverse workforce. In addition to our Young Energy Professionals Forum, we are a founding member of TIDE, an industry-wide taskforce to tackle Inclusion and Diversity across energy

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Context and proposal summary

In December 2024, DESNZ published three documents on the Capacity Market:

1. [A call for evidence \(CfE\) on consumer-led flexibility](#)
2. [Proposals to modernise Rules and improve participation and delivery assurance of consumer-led flexibility](#)
3. [Capacity Market Statutory Five-year Review 2019 – 2024 \(referred to as the “Ten-year Review”\)](#)

The consultations close in February 2025 and the government aims to respond in Spring 2025 and to implement relevant proposals, before prequalification in 2025.

This response focuses on the CfE into Consumer-led Flexibility. The new proposals build on those set out in DESNZ's Phase 2 proposals (end 2023) and cover the following themes:

1. Generating Technology Classes (GTCs)
2. De-rating: Methodology and Duration limits
3. Component reallocation within aggregated portfolios
4. Management of aggregated small-scale assets
5. Baselining methodologies
6. Completion Milestones

The National Energy System Operator (NESO) estimates that the electricity system could require 30 to 40GW of short duration, (and 40 to 45GW of long duration) flexible capacity by 2030. Making the CM more accessible to DSR could provide a key role in enabling DSR to scale-up to support both security of supply and government's Clean Power mission.

Previous responses in this area include the following:

- [Energy UK response to DESNZ consultation on the Capacity Market: Phase 2 proposals and 10-year review](#) (December 2023)
- [Energy UK response to Ofgem's 10-Year Review of Capacity Market Rules](#) (Feb 2024)

Summary of Energy UK response

We welcome the intent to open up the Capacity Market in line with the Government's Clean Power mission. Whilst some of the proposed changes will be beneficial, the overall package, reads as two steps forward and at least one step back. Some of the proposals would introduce new barriers by requiring more arduous conditions for DSR than other technologies.

We recommend that the proposals that introduce new barriers (for example, duration limits) should not be taken forward, and that there is more discussion with industry to identify positive proposals. A key priority here would be on the approach to component allocation (Q10). A further improvement would be to facilitate a bulk upload into the system.

We note that whilst we welcome and support ongoing changes to improve access to the CM, it will continue to be inaccessible for most domestic (as well as manual non-domestic) DSR until Market Wide Half-Hourly Settlement is completed in 2027. This is due to the requirement for either a boundary meter settled on a half-hourly basis (or balancing compliant asset meter – the cost of which is likely to be prohibitive for much domestic DSR). Since domestic DSR (where it has a route to market), supports security of supply by reducing peak demand, this inability to access CM support amounts to a structural disadvantage. Energy UK has elsewhere argued that until there is widespread access for domestic DSR to the CM, that alternative provision should be made elsewhere (for example by through an availability payment for the Demand Flexibility Service¹).

Response to Consultation Questions

Q1: Agree with proposals to introduce new DSR GTCs based on tech. type?

Yes. As with our response to Q22 in the 2023 Phase 2 consultation, Energy UK supports the creation of additional GTCs for DSR. Further to this, we support the current proposal to introduce the additional GTCs based on technology type.

This support assumes (and is conditional) upon the assumption that the new GTCs will apply at the component rather than at the CMU level.

Question 2: Please provide reasoning and supporting evidence where appropriate. If you disagree, please provide suggestions and evidence for alternative methods.

As noted above, the support in Q1 assumes (and is conditional) upon the assumption that the new GTCs will apply at the component rather than at the CMU level. As such, the creation of new GTCs would not, we assume, restrict the ability of providers to have CMUs with multiple different DSR GTC types.

We highlight here that diverse portfolios is an important tool to ensure reliable performance in DSR CMUs. For mixed CMUs, our assumption is that the total derated capacity of the CMU would be the sum of the derated capacities of all its components. We note that this is the current approach for generation CMUs with mixed generating GTCs (e.g. gas and diesel generation).

The performance of the CMU would (as now) be based on its ability to meet its obligation (the sum of the derated capacity from the various GTCs and their components).

¹ This point is made here in the [Energy UK response to Demand Flexibility Service \(DFS\) EBR Article 18 consultation - Energy UK \(August 2024\)](#)

We would not then, support a requirement for components in CMUs with multiple DSR GTCs to have to be replaced on a like-for-like basis, or to prevent the mix of GTCs being changed between the auction and delivery. The requirement should (as now), be to assemble or replace components in a way that allows the CMU to deliver the contracted obligation.

Question 3: Do you have any opinions on whether an additional GTC is necessary for EVs and V2G technologies, or can these be included in the proposed categories?

In general, we back more granular GTCs since these will support DSR providers to identify the most suitable GTC and associated derating factor for their technology / risk appetite / business model. We agree that this should increase the accessibility of the CM to DSR providers (including new entrants / new business models).

More granular DSR GTCs would also provide more data to monitor the emerging sector, and how to best deploy the resource to support security of supply. For these overarching reasons, we would support the 3 proposed GTCs on BtM storage, BtM generation and genuine DSR (including turn-down), as well as 2 further GTCs on EV and V2G.

EV GTC - The ability to dispatch an aggregated-EV portfolio might differ from that of a BtM storage CMU. If a EV CMU was called on a winter night during the evening peak, there is a higher risk of components not participating (evening commute) than for the BtM storage BMU. The EV CMU provider might prefer to use a lower derating factor to cover off this risk.

V2G GTC - Our recommendation here is for V2G to either use the BtM generation GTC or have a dedicated V2G GTC. V2Gs would not fit naturally in a EV GTC given their ability to export as well as import. Our preference would be for providers to be able to opt for the GTC that works best for their business model.

Question 4: Can you foresee any unintended consequences that might arise from the introduction of separate GTCs for EVs and V2G?

The caveat to our support for more granular GTCs, is that it is straightforward:

- i) for relevant assets to move between the new DSR GTCs (so long as the CMU continues to meet its derated capacity obligation, possibly by adding extra components), and
- ii) for the Department to alter the GTCs in the future

This would prevent new administrative burdens arising from customer-side changes (such as swapping flex/ retail offers), upgrading hardware (from EV to V1G [only provide services when charging] or V2G), or from customers switching off their charger's V2G function. To enable this, we recommend an exemption to Rule 4.4.4. and note the recent 4.4.4. exemption that was formalised for battery augmentation (2024).

We support the change, if implemented based on the following principles to not restrict what the provider can do or result in additional cost. Our views here are as follows:

- i) Onus on the provider to choose GTC

Parties should be allowed to choose the level of risk. This point applies more generally: Great Britain has aging generation assets so providers should be able to opt for lower-risk derating factor. This would formalise the fairly widespread practice of BESS providers entering assets with a lower connection capacity to mitigate the risk of battery degradation.

There are some differing views here on whether DSR providers should have the option of derating themselves. Our view is that it would be most appropriate for the genuine DSR GTC as it would be able to then accommodate different customer groups.

ii) Components need not be replaced on a like-for-like basis

Components should be able to switch where this does not affect the obligated delivery capacity of the CMU.

iii) It does not result in additional submetering requirements for diverse CMUs

If a CMU includes, for example, both EV and V2G components using two GTIs (with different derating factors), we would not support a requirement to sub-meter either GTI separately (given the additional cost this would entail).

We note that there are two approaches to manage mixed CMUs – either:

- a) The sum of derated capacity² or,
- b) Material thresholds (for example, a CMU covering 1 site in which 80 of the DSR volume comes from the commercial building and only 10 percent from EV fleet charging, is classed as building DSR).

We note the proposal in the accompanying consultation ([CM proposals to modernise rules and improve participation and delivery assurance of DSR](#)) on reducing the administrative paperwork for DSR.

Unintended consequences

Whilst we would support some flexibility between DSR GTCs, we note a potential risk of providers entering assets under an inappropriate GTI. This occurred in 2019 when the CM rules were initially changed to remove the prohibition on DSR CMUs having multi-year capacity agreements. Since the existing capex threshold was retained, DSR could not benefit from the change, but there was a concern that storage in a DSR CMU would be able to benefit, and would have an incentive to masquerade as DSR.

To prevent this, DSR providers were required to carry out an Extended Performance Test (EPT) for the whole CMU if it contained any storage components, with the prohibitive additional costs that this entailed. A better way of avoiding this unintended consequence would have been to remove the ambiguity on whether storage was permitted in a DSR GTC, and to apply storage-related tests and de-rating only to any components with storage GTCs.

We would advocate for a similar approach here. If it is clear and unambiguous what assets (and cannot) can be classed in each of the DSR GTCs, then DESNZ will be able to take appropriate action (for example contract termination), if a rule has not been upheld.

Question 5: What are your views on the utilisation of non-BM STOR in current DSR de-rating methodology? Do you have any alternative suggestions?

Non-BM STOR is no longer an appropriate basis for two reasons:

- i) there is little DSR in STOR - the service parameters render it largely inaccessible;
- ii) STOR closes at the end of 2025 (so the change would need to be carried out before the ECR in mid-2026).

Currently most non-BM STOR is from gas reciprocating units (with some diesel generation). We are not clear if the derating factor comes from this dataset as a whole, or from the small

² = (x EVs * EV derating factor) + (y V2G * V2G derating factor)

'Other' subcategory which includes some DSR volume (which would provide a more accurate basis). Whilst we agree that STOR would have been the best available data when the methodology was developed, it is unlikely to be so now and should be updated.

Alternatives

Members agree that the DSO product, 'Sustain' (providers change their supply/demand up or down to help manage network constraints) is likely to provide the best source, if there is sufficient data. Whilst we understand that there have been relatively low volumes to date, (Ofgem RIIO-ED3), most of this has been dispatched by UKPN and NGED, so we recommend that DESNZ speak with the relevant teams there. We recommend that this is reviewed in 2 years in case a better data set has become available.

Other options:

- Demand Flexibility Service (DFS): the lack of penalties in this market, largely manual volumes (c. 90%) plus the significant changes between each of the 3 services over the past 3 years suggest this might not be a useful comparator.
- Local Constraint Market (LCM): low volumes

There is more data on the volumes of DSR in NESO and DSO services in the NESO's Power Responsive 2023 annual [report](#)³

Future change

- Slow Reserve: this forthcoming service (Q2/3 2025) will take over from STOR and is intended to be more DSR accessible (design not confirmed yet). As the CM methodology requires 3-years of data, an option would be to use the DSR data from the 'Other' category in non-BM STOR (if monitored separately by the NESO) and transition over to the Slow Response data as this becomes available).
- P415: this BSC code modification created a vehicle that will enable non-supplier aggregator to trade DSR in the wholesale market. The impact/ data utility is not yet clear however (two Virtual Trading Parties registered to date and one small trade made to date).

International comparators: Given the fairly limited datasets for GB, it would be worth looking at international examples to see if data or approaches used elsewhere could be applied here. For example, the CM proposal for Spain will cover all markets during peak hours to understand the availability of the resource to provide any service. A parallel approach here could look at participation through P415, in the Balancing Mechanism (BM) etc and what percentage of their nominal resource they have available in peak hours.

Question 6: Do you agree that DSR exhibits duration limits?

In general, members agree that with the view expressed in the publication (reproduced above) that DSR Tests over longer durations would deter participation and likely be economically inefficient. Unlike storage resources, which have hard technical duration limits, most DSR resources do not have firm limits, but instead suffer increasing opportunity costs as the duration of a dispatch increases. This makes long-duration tests prohibitively expensive, even though DSR resources can sustain very long duration dispatches in a genuine emergency, (as seen by PJM in Winter Storm Elliott).

³ <https://www.neso.energy/document/320951/download>

On the underlying question of how reliable DSR might be in a SSE, and derating factors, we note that ‘reliability’ is, in part, a function of scheme design. The UK CM was designed as an ultimate last resort, but penalties for non-delivery were initially quite low. The inherent risk of a design that is designed not to be called, is that it incentivises providers to opt for the highest de-rating factor within their tolerance. In contrast, a design with a higher probability of usage but more punitive penalties, would incentivise providers to reduce their risk. The recent dramatic increase in non-delivery penalty rates, along with the higher likelihood of stress events in future years, has probably corrected the initial imbalance.

Question 7: Do you agree with proposals to adopt a duration limited methodology to de-rating DSR categories?

No. Energy UK does not support a proposal to adopt a duration-limited methodology to de-rating DSR categories at this time.

As noted above, most DSR resources (except behind-the-meter storage) do not have hard limits to their dispatch duration – they don’t run out of energy. Rather, the cost of their response tends to increase with the dispatch duration.

DSR is at a relatively early stage in its development (especially domestic), and faces significant barriers to market access, revenue stacking etc. Needs a fixed time period before review.

Future application

We note that as newer technologies become more prevalent, the de-rating methodology may need to be reviewed. We recommend that this this proposal is left for now but revisited again in 2028.

Alongside this, we note a wider need to review (and potentially update) de-rating factors across all technology types. For example:

- there is no de-rating factor for reciprocating engines (the derating factor for OCGTs is used).
- there is no de-rating factor for energy-from-waste plants (instead the coal derating factor despite there being no coal power in GB today)
- We further note that past recommendations/ analysis for revising de-rating factors for other technology classes have not been acted upon.
- For example, an NG ESO study on using distributed data for gas and diesel reciprocating units (which concluded that derating factor would be reduced with this approach) was not implemented and no further update has been provided.
- Neither has the PTE’s recommendation ([2021](#)⁴) *64: The consistency of the implicit de-rating of interconnectors for the DDM procurement analysis and the determination of individual country de-rating factors should be made more transparent.*

Members have some concerns that, whilst well intentioned, some of the new proposals could create new barriers for DSR by requiring additional requirements/ higher standards than for other technology classes. Therefore, if Government decides to proceed with a review of de-rating methodologies for DSR, we encourage this to be undertaken as part of a holistic review of all of the outdated de-rating methodologies (including for reciprocating engines and energy from waste).

⁴ <https://assets.publishing.service.gov.uk/media/60e371138fa8f50abf416f65/panel-technical-experts-report-on-2021-electricity-capacity-report.pdf>

Question 8: Do you have views on whether this approach should be applied across all proposed DSR categories?

Energy UK does not support adopting a duration limited methodology for DSR at the moment for the reasons outlined above.

Question 9: Do you foresee any unintended consequences from adopting a duration limited methodology?

Energy UK does not support adopting a duration limited methodology for DSR at the moment for the reasons outlined above.

If further changes are made going forward we would support the approach (to update derating factors) to be consistent across all technology classes. There is otherwise a risk of inadvertently introducing new barriers.

Question 10: Do you agree with our proposed approach to component reallocation within DSR GTCs?

Government's policy intent is not clear from the consultation. There is no explanation of why GTCs would need to be provided at prequalification or why component switching would only be allowed within a GTC.

As per our response to Q2, we do not agree that using a mix of GTCs within a CMU should lead to component reallocation only being allowed on a like-for-like basis. The important thing will be to ensure that the CMU as a whole has a de-rated capacity after any changes that is at least as high as its capacity obligation.

There is no reason to require that the obligation is achieved in the same manner. This would be an unrealistic restriction for aggregated portfolios with a high level of churn and unnecessary – the ability to deliver the obligated capacity is what matters. We note that any domestic CMU will inevitably have churn given the retail market focus on retail switching.

If the Department's view is that Rule 4.4.4 would require component reallocation on a like-for-like basis, then our recommendation is for a carve out from Rules 4.4.4 for DSR portfolios (as with the recent clarification on BESS augmentation implemented in the CM Rules).

On Rule 4.4.4, we note that, whilst members generally accept that it is there to prevent some risks, the way it is implemented is not consistent. Since lack of clarity here risks stalling potential innovation, we recommend that DESNZ issue guidance (in time for the 2025 auction) to clarify what is allowed under 4.4.4. A useful approach here could be to request views on what participants believe is allowed (as an example, would CCS on a gas plant change the configuration?), and then for the Department to respond.

Question 11: Do you believe that additional supporting changes are necessary to accommodate the proposals outlined in question 10?

Yes – to remove the component allocation limit altogether – it is inherently incompatible with domestic DSR given the policy focus on customer switching in the retail market.

Limiting component reallocation will reduce the reliability of DSR especially domestic DSR. Having a limit on reallocations cannot prevent customers from leaving a portfolio, as this is the customer's right: there is nothing the aggregator can do to force them to continue to

perform. So component reallocation limits just prevent this reality from being reflected in the make-up of the CMU and, more importantly, prevent the customer being replaced so as to maintain reliable delivery of the CMU's capacity obligation.

We noted this in [our response](#)⁵ to the Phase 2 response (December 2023, Q20):

'Members support the principle of lifting the current component re-allocation limit of 40 components but most members commenting here do not agree with the new proposed proportional component reallocation limit. Members here highlighted the level of data that could be required to implement this rule for domestic DSR CMUs and question the value that this would provide. The core issue seems to be around IT infrastructure to manage component reallocation. The focus should be on ensuring this infrastructure and the rules are fit for purpose. It was also noted that any component reallocation limit conflicts with retail policy which aims to facilitate customer switching as a means of delivering improvement via competition.'

If the policy intent is to reduce barriers to DSR, especially to new additional capacity such as domestic DSR, there should not be a limit on component allocation. The 40% threshold represents a risk for domestic DSR providers. If customer churn exceeded this within the lifetime of their agreement, they would need to operate their CMU with fewer customers, reducing their available capacity, meaning they would have to accept declining revenues or trade away their obligation to another provider or risk being unable to fulfil their contractual obligations. Members further noted that the 40 percent appeared arbitrary and more related to the administrative limitations of the DB/ the DB's IT systems than the CM's objectives. Members here noted that the DB resource here could be better allocated to ensuring that CMU with customer churn are able to maintain their capacity, duration and reliability as an aggregate unit as opposed to collecting granular data on the (potentially thousands of) individual components. Some members queried whether the testing requirement should be stronger for domestic DSR above a threshold of customer churn. The providers working in this space highlighted the 3 SPDs as a tool to manage this risk along with the strong incentives to maintain reliability'.

Question 12: If you believe additional supporting changes are necessary, what changes should be considered?

As above, we note the importance of integrating domestic DSR given the centrality of customers to the Government's Clean Power mission.

Question 13: Do you agree that information submitted with respect to aggregated CMU could be reduced without negatively impacting delivery assurance?

Yes. Where all the information is the same, it is important that it can be submitted more easily to reduce the administrative burden for both participants and the DB.

As in Energy UK's [response](#)⁶ to the Phase 2 2023 consultation (Q19), there is scope to go further, faster if DSR (especially domestic DSR) is to scale to meet the ambition set out for it in the Government's Clean Power Mission.

Question 14: Please present views on how any alternative approaches could be addressed and implemented.

In general, members feel that the too much information is required by the DB and they would like to see a different approach to reduce the administrative burden for participants.

We note that the DB has ability to audit things that it is concerned about as well as to require director-level sign-off. These approaches could be used to reduce the volume of data

⁵ <https://www.energy-uk.org.uk/publications/energy-uk-response-to-desnz-consultation-on-the-capacity-market-phase-2-proposals-and-10-year-review/>

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required upfront. For DSR, it is necessary to design a proportionate approach rather than replicating a process designed for large assets.

Our response to the 2023 consultation for example, noted the proposal on partial redaction of addresses on the CM registers did not go (and does not) go far enough:

'Members here query why so much data (sensitive or otherwise) is required for registration when comparable DSR programmes generally restrict data to the meter data ID, (the MPAN) with further data available on request for audit purposes if required. The consultation document notes that as the market for domestic DSR expands, the CM might need to handle data for hundreds of thousands of meters. Requiring this level of data is not practical for either the DB or participants for domestic CM with customer churn. It would increase the overheads for both the DB and participants to administer without clear benefit. National Grid ESO's Demand Flexibility Service (DFS) which operated for just 6 months last winter, registered 1.6 million individual MPANs across 20 test events in six months. This highlights the volume of data that the DB might be required to manage under the current proposal and the difficulty/ unnecessary overhead that this could create for both the DB and participants. If the CM's administrative process is to enable rather than limit domestic DSR, then the administration will need to fit the technology (rather than the reverse). As an example of the current administrative unsuitability, a member working with small, aggregated loads in the CM noted here that they have crashed the CM portal many times with only hundreds of components. One member noted that a similar point could be applied more widely to the CM's administration. The administrative burden for providers (and cost to the DB) of collecting data and then rejecting it for minor discrepancies could be reduced if the registration was more proportionate and built on existing data where possible.'

Question 15: Do you have views on changing baselining methodologies in CM?

Our initial point is that the description of how the current process works is unclear/ not correct. This is a concern, it this provides the rationale for the change.

- The baseline process requires six weeks of data, *rather than data six weeks in advance.*
- Providers can choose when to do the Satisfactory Performance Day (SPDs) or tests, *not which settlement periods to source the data from.*

Aside from this, we note that that the issue that DESNZ are looking to tackle here - that a period chosen by the provider might not be representative for stress events - is not just a DSR -specific issue but a general issue: generators, too, can choose when the test period is for SPD. Requiring a different approach for DSR providers here would be to require a higher standard than is required for other technologies rather than a technology-agnostic approach. We do not support this.

On the baseline question, we do not consider this a priority and recommend that the Department focus on opening up the CM for DSR (especially domestic DSR) given the Government's Clean Power mission. An alternative would be P376, but we note that it is quite similar to the current approach.

Question 16: Do you have views on aligning baselining methodologies with other markets?

Interoperability of baselines - there is work required on an industry-wide approach to ensure that baselines are *interoperable* so that dispatch in one market does not undermine a customer's baseline for another service. There is an ENA Open Networks workgroup progressing this work currently. Achieving interoperability is not the same as requiring that the same baseline methodology be used in different markets. There are many trade-offs in choosing baseline methodologies; the most appropriate methodology for a particular resource will depend on the notice period and likely dispatch duration, which varies between markets.

We note that the low-levels of DSR (and stacking) mean that this is not urgent (though it will become more important as DSR volumes increase). This can build on the current approach for applicable balancing services that allow a generator to have a CM contract whilst delivering ancillary services.

Question 17: Do you have views on how changes to the penalty regime could incentivise more accurate baselining in the CM?

The proposal and rationale is not clear here. The Department looked at changing the penalty regime in Phase 1, it was not widely supported and the decision was made not to do so. Members are not clear why this is being reconsidered (if this is the proposal) and do not support it.

The 2021 [Call for Evidence on Capacity Market - early action to align with net zero](#) proposed changing the figure used in calculating the penalty rate from 1/24 to 1/4. Our [response](#) (Question 18) did not support it, viewing the suggested penalty rate as disproportionate to the objective, especially without the introduction of complementary measures to improve efficiency (including modelling on potential duration of stress events) and improvements to secondary trading. We noted that by increasing the risk of participation, the proposal could reduce market liquidity and so increase total costs.

As noted in other questions, we do not support a different approach (on penalties/ baselining etc) being taken for DSR than for other technologies. The impact of this would be to introduce new barriers rather than to make the CM more accessible to DSR.

Ancillary and BM services are already accounted for in the delivery of stress events within CM rules. That should continue to apply for DSR (we note this may need to be updated to include the NESO's Demand Flexibility Service (DFS)) in the Relevant Balancing Services document.

On baselines, we note that the baseline methodology is not compatible with dynamic tariffs (where the price in a particular interval might be high today despite being low at the same time on previous days). Whilst there are relatively few customer on dynamic tariffs today, they will become more prevalent with MHHS and higher deployment of smart assets.

Question 18: Do you agree with intentions to introduce a completion milestone ahead of the relevant ECR?

It is not clear from the CfE what DESNZ are considering as a completion milestone but we do not support the proposal as we understand it.

We would stress that the DSR test plays an equivalent role in the CM to the substantial completion milestone for generating technologies. The equivalent proposal for generating CMUs then would be to move forward the commissioning date for new builds to avoid risk of over-runs). We would not view either as a proportionate response.

In the case of DSR, moving the test date forward would reduce the time providers have to recruit customers. This is a very substantial, resource-intensive part of the job of an aggregator. It's "building" the portfolio. The impact of reducing the time available to do this would be some or all of the following unintended consequences – lower procurement volumes, lower quality resources (enrolling customers in a rush increases the likelihood of unsuitable customers being enrolled, undermining reliability) and/ or higher costs for the provider (higher staff costs to undertake recruitment in a shortened timescale).

The Government is seeking to introduce a termination fee for failure to deliver a DSR Test (in the consultation on consumer-led flexibility), to increase the delivery assurance. Other proposals here are not needed in our view (and risk introducing new barriers to DSR rather than removing them).

Question 19: Please explain the reasoning behind your response and provide supporting evidence. If you disagree, please provide suggestions and evidence for alternative methods.

Whilst we note the issue with non-delivery, members are not clear that this is specific to DSR. More data would be useful here to that industry assess the material risk and provide a proportionate response. We note that the Panel of Technical Experts (PTE) has also asked the Department to respond with more detailed data on what is dropping out and why.

This proposal seems to be requiring an additional check for unproven DSR that is not required for other technologies and so on the evidence and rationale presented, we do not support it.

We note that the 2017 [Capacity Market Consultation - Improving the Framework](#) (July 2017) proposed that providers should carry out the DSR test before the T-1 auction as a means of improving delivery assurance. This suggestion was for Unproven DSR CMUs to fully commission their entire portfolio 13 months ahead of the start of the Delivery Year.

We note that this proposal confused evidence of ‘progress’ with expectation of ‘completion’ – and is not a reasonable expectation of either unproven DSR or a new build unit and would have reduced the time available for DSR providers to recruit their customers from by almost half (from Auction Results Day to “end of sales”).

As noted above, we think the current proposal to introduce a termination fee for failure to deliver a DSR Test will increase the delivery assurance, so other proposals here are not needed.

If the Department is of the view that a material risk will persist, then the alternative approaches listed below could be considered instead. Members here would support more consideration of incremental testing to prove capacity in return for credit cover (as used in ISO New England). This would provide more certainty in time for the ECR but we note that it would require rolling tests - which would be a significant change.

Alternatives options

- A progress monitoring regime for Unproven DSR CMUs. This would give the DB more visibility of the provider’s recruitment and could be achieved (as in Western Australia) by regular reports on the customers under contract and the sales pipeline. We note that for unproven DSR, this could mean the contract holder can losing their bid bond if fail to deliver.
- Component-level DSR Tests – common in other markets, these would allow aggregators to test customers as they are signed up, rather than waiting to test them all at once at the last moment.
- If credit cover was returned proportionately as Unproven DSR Capacity was proven in these component-level DSR Tests, this would incentivise aggregators to enrol customers as early as possible. If necessary, this incentive could be strengthened (as in ISO-NE), by increasing the level of credit cover required for the remaining not-yet-proven capacity after certain milestone dates. Setting a milestone date just before the last opportunity to adjust the target volume for the T-1 auction could reduce the perceived risk and be

somewhat analogous to the additional credit cover required from New Build CMUs under Regulation 56(4). The difference is that DSR is a scalable resource. As such, if the provider has already proven 30 MW of their 50 MW obligation before the milestone date, they should be able to choose whether to post additional credit cover for the remaining 20 MW, or surrender part or all of it, paying TF1 for the surrendered capacity.

Question 20: Do you foresee any unintended consequences from earlier introduction of completion milestones?

We are not clear on the proposal here but as set out in our response to Q19 such a proposal could disadvantage DSR compared with other technology classes and reduce the time available for customer recruitment leading to some or all of the following impacts – lower volumes, less reliable components, higher costs.

In general, our recommendation is that proposals in this space need more engagement with industry (both providers and customers) given both the challenge of retrofitting the CM, the timeframe to CP2030 and the required timeframes for making changes to the CM.

There is a real risk that some of the proposals, while well-intentioned, would introduce new barriers to DSR. We urge the team to focus on the key areas of design that would unlock DSR rather than introducing new requirements that do not apply for other technology classes.