Via email to: tsc@cru.ie and caroline.winder@uregni.gov.uk

25th October 2024

Re: Demand Side Units: A Revised Phase 1 Solution for Energy Payments and Other Issues SEM-24-046

Dear Sir/Madam,

I am writing on behalf of the Demand Response Association of Ireland (DRAI), a group that represents flexible energy demand customers participating in the all-island Single Electricity Market (SEM). These flexible customers form predictable, reliable, and controllable assets, which provide a valuable source of Demand-Side Flexibility (DSF) that can be actively used by system operators to meet the near time needs of the power system.

Today, the DRAI represents approximately 700 MW of demand and embedded generation response across hundreds of industrial and commercial customer sites throughout the island of Ireland. These sites are managed by our members each of whom actively participate in the capacity, DS3, and energy markets.

DRAI members are committed to shaping the future of power system flexibility through advancing DSF on the island of Ireland. The organisation expresses a single voice on policy and regulatory matters of common interest to its members, and we welcome the opportunity to respond to the DSU Energy Payments consultation (the "**Consultation**").

Regarding energy payments and supplier compensation charges, it is important to remember the ultimate purpose of granting DSUs full and equitable access to energy payments, which is to appropriately incentivise optimal levels of demand side flexibility. Getting this incentive right has the potential to unlock additional quantities of demand response, saving costs for all users and delivering system-wide benefits. It is important to focus on this, rather than on trying to maximise the volume of supplier compensation payments.

We make a specific proposal for a revised approach to supplier compensation payments that we believe will, (a) work correctly when fully implemented as a permanent solution including supplier perimeter correction, and (b) be acceptable in the nearer term, in that it gives appropriate economic signals while avoiding harming any participants.

On behalf of the DRAI we hope that you consider the points we have put forward, and we welcome future engagement on the matter.

Your sincerely,

Patrick Liddy

DRAI

DRAI's proposed solution

These measures are proposed on a workable interim basis, providing a pathway to a fully compliant enduring solution, and in an effort to support this consultation process and to prevent further delay to the full and equitable access of DSUs to energy payments.

While the Consultation remained vague as to the specifics of the compensation price, the methodology for calculation, and settlement, the DRAI notes that Section 3.5, proposes some options for determining PCOMP including "*using some form of average price, which could be, say, a three-month rolling average of the Day-Ahead Market baseload price or mid-merit price, recalculated each month, plus the Capacity Charge and the Imperfections Charge;*" (the "**Proposed Option**")

The DRAI's proposed solution builds on this option within the Revised Phase 1 Solution, while expanding it to cover the practicalities of implementing such a solution. This includes calculating the Supplier Compensation Price (the "**PCOMP**") by starting with the Average Day Ahead Market (the "**DAM**") price, the use of a 90-day rolling average, the necessary settlement mechanisms, the interaction with Reliability Option difference charges, and the inclusion of some proxy for the benefits of demand response for the system.

The following issues are vital to ensure that no DSUs are unfairly disadvantaged or rendered non-viable by this mechanism and prevent scenarios in which they are exposed to liquidity issues, or extensive losses as a result of the design.

1. *The use of the DAM Price*

Several options were put forward by the SEM Committee as to which price to base PCOMP on. One particularly worrying proposal was to calculate the supplier compensation price as an administratively determined proxy for the average retail price. While this would elegantly solve the "missing money problem" for high cost DSUs (colloquially "*short run*" units), it would radically undermine the viability of low cost DSUs (colloquially "*long run*" units), and the DRAI do not believe any market mechanism should make such a distinction.

A fundamental requirement of Directive (EU) 19/944 (the "**Directive**") Article 17(4), and indeed the Network Code for Demand Response (the "**NCDR**")[1], is that the compensation to suppliers should be "*strictly limited*" to "*specific, verifiable additional costs directly associated with the demand response activation*". While we acknowledge that in Phase 1, it will not be possible to verify the specific costs, it is critical to effectively limit the compensation to the incurred costs, to form a basis for the subsequent Phase 2. Given the nature of DR activations, the supplier does not incur many of the costs that make up the retail price such as TUoS, DUoS, Loss Factor, Capacity Charge, Imperfections Charge etc. Therefore, the only cost that is genuinely incurred by suppliers in the event of an activation is the price they paid for the energy that wasn't consumed.

With this in mind, the supplier compensation price should be a proxy only for the supplier's cost of sourcing the energy. Average prices in the DAM, as per the Proposed Option quoted above, are an easy and sensible approach, and appears to be the only one that ensures fairness for all DSUs and suppliers.

[1] *Article 17(4) of the Directive, Article 22b of the NCDR proposed by ENTSO-E & EU DSO, Article 55A of the EBGL proposed by ACER through the NCDR. Collectively, the "**EU Law Provisions**".*

It is worth noting the that extensive supplier windfall that remains intact with this mechanism, as recognised in Section 2.2 of the Consultation; "*It was recognised that this Phase 1 solution would result in concerns of double counting, in that demand reduction would result in both savings in purchase costs for the supplier as well as explicit payments to the DSU*". While the extensive supplier windfall will be removed by the envisaged Phase 2 solution which will correctly adjust the imbalance volumes between the DSU aggregator and impacted suppliers, this remains intact with the proposed interim mechanism due to the stated complexity of implementing the proper solution as per Phase 2.

Furthermore, the DRAI's solution does not require any complex administrative process to determine the PCOMP.

Using the DAM price will ensure that the same PCOMP calculation can form the basis for the enduring Phase 2 solution that is compliant with the EU Law Provisions, including the requirement for supplier compensation not to be an undue barrier for these units. It will also ensure that "*long run*" units remain viable. This appears to be a stated goal of the Consultation (Section 3.5 "'*Long run DSUs' neither lose, nor benefit, significantly from differences between the supplier compensation payment and the average costs of purchasing from the SEM")*. The implementation of a measure that would hamper the viability of these units would have several adverse consequences for the system, including:

- a reduced financial incentive for onsite generation; reducing capacity available to the system,
- a reduction in the volume of behind-the-meter generation visible to / controllable by the TSOs,
- a reduced incentive to be operating at times of system stress,
- no incentive for behind-the-meter generation assets to be curtailed at times of high renewable penetration, leading to greater levels of renewable curtailment

There would also be consequences for aggregators and final customers participating in DSUs. The most striking being the inability of aggregators to fulfil capacity obligations held out to 2029 given the negated value of so called "*long run*" units. Final customers participating in DSUs would lose the revenue that currently helps to offset high energy costs, as well as a means to support the grid. The DRAI fundamentally believes all forms of DSU benefit the system and end users, and the Revised Phase 1 Solution – specifically the use of any price other than the average DAM price (e.g. the mentioned proxy for the retail price) – risks removing this benefit.

2. *The use of a 90-day rolling average*

The Proposed Option suggests a rolling average. The DRAI supports this: without substantial averaging, DSUs would have no incentive to respond to day-ahead price signals. The use of a 90-day rolling average DAM price is recommended to mitigate the volatile nature of the wholesale prices. Using a shorter averaging period would blunt the price signal to so called "*short run*" units during periods of scarcity, once the supplier compensation is netted off earned revenue, whereas the use of a longer averaging period may risk large liquidity exposures that do not take account of changing seasonal prices. The DRAI believes using a 90-day rolling average period to determine the PCOMP strikes the most appropriate balance.

For reasons of practicability, the 90-day rolling average should be calculated weekly, *ex-ante* for each Settlement Week, as opposed to a calendar month period.

3. The use of weekly settlement mechanisms

While not addressed in the Consultation, the DRAI believes the most appropriate mechanism for settlement is the netting of the supplier compensation in weekly settlement, prior to payment. This mitigates any time lag between payments and repayments, preventing liquidity issues. In the same way as Make Whole Payments are calculated at the end of each Settlement Week, any Supplier Compensation Charges would be calculated weekly and effectively netted off the energy revenue received by each unit at source.

4. The use of the lower of the strike price and the 90-day rolling average

It is essential that the Supplier Compensation mechanism is designed so as to avoid any negative interaction with Reliability Option Difference Charges. It is important this is designed in such a way that all performing DSUs have appropriate access to revenues to cover their Difference Charge exposure, and the Supplier Compensation payments do not erode this. A key concern of the DRAI is the possibility of PCOMP rising above the Reliability Option Strike Price for any period. While this may seem unlikely, it is important that all such scenarios are carefully factored into the design. If PCOMP rose above the Strike Price and there was a Reliability Option event this would lead DSUs to be paying back twice for any energy payment in excess of the Strike Price, which is clearly not appropriate. To avoid this risk, the PCOMP must be set to the lower of the Strike Price and the 90-day rolling average DAM price.

5. The inclusion of a proxy for the benefits of DR on a per MWh basis

It is also important that the wider full system benefits of demand response are taken into account when calculating Supplier Compensation Payments, as per Article 17(4) of the Directive, Article 55a (4) & (5) of draft EBGL revision, and Article 22(b) of the ENTSO-E & EU DSO Entity NCDR. Such benefits included in these articles are the lower wholesale prices as a result of DR activations, the lower network tariffs (especially due to units with on-site generation), lower system operation costs (especially due to units with on-site generation), and many more.

While the DRAI understands it is complicated to fully quantify these benefits, the SEM Committee could use a proxy value for these benefits based on historic data and apply this on a per MWh basis to the PCOMP, reducing it by the appropriate value.

Conclusion

DRAI urges the SEM Committee, that, if it a supplier compensation measure is to be imposed in conjunction with energy payments being granted to DSUs at all times, it is essential that this is in the line with the above propositions in order to ensure that the enduring Phase 2 solution complies with the relevant EU obligations. Namely, the Supplier Compensation Price should be determined as the lesser of the Reliability Option Strike Price and the 90-day rolling average DAM price without the addition of any further charges or costs and including a €/MWh reduction to reflect the full system benefits of demand response.

The relevant EU Law Provisions, both in draft and in force, are prescriptive in nature as to the costs that may be included in the compensation price. These do not include costs that have not been incurred as a result of the non-delivery of energy. Therefore, the DRAI contends that only the DAM price should be included as the starting point for the PCOMP, which should also be adjusted for the net benefits brought by DR on a per MWh basis. Furthermore, key practical elements must be considered to prevent liquidity issues and unintended losses for DSUs in certain scenarios.

Preparations for Phase 2

The above proposal is an acceptable interim, or Phase 1, solution in that it gives appropriate economic signals whilst avoiding harming any participants. However, we also believe its general structure will work correctly when fully implemented as part of the permanent solution envisaged for Phase 2, including supplier perimeter correction.

Consultation Questions

The DRAI would like to state that many of these questions are not relevant to the issue of granting DSUs energy payments at all times. Furthermore, many issues have been subject to previous dialogue between the industry and the TSO, and do not warrant further consultation. These questions merely act as a distraction from the more fundamental issue of DSU energy payments.

Nonetheless, in order to participate in earnest with the Consultation, we have responded to the following questions.

Q1: Do you agree with the description and analysis of the models for compensating demand response and, in particular, for energy payments to DSUs? Please explain your view.

Model 1 (No DSU Energy Payments) – The DRAI agrees with the description of this model, as well as the recognition of the need to change to one in which DSUs are actually compensated equally to generators for the energy provided to the system.

Model 2 (DSU Energy Payments with supplier billing) – The DRAI largely agrees with the description of this model and contends that Models 2 and 3 are the only ones that comply with the EU Law Provisions. However, the statement "*There will need to be a side payment from the DSU to the customer to cover these costs"* suggests there is a misunderstanding by the SEM Committee of the current arrangements: DSU aggregators pass most of the revenues they receive through to the end-consumer.

Model 3 (DSU Energy Payments with supplier compensation) – The DRAI somewhat agrees with the description of this model, however, a key point is misrepresented - DSU aggregators would not seek any payments from participants, regardless of their savings, and always share the revenue earned. However, we agree that if done correctly (directly attributing the demand reduction to the correct supplier, and using the correct PCOMP) then this could be a viable measure. This also assumes no bilateral contract would be needed between the aggregator and the supplier, which would set back the industry considerably, as well as being inconsistent with the requirement Article 17.3(a) of the Directive, which states that an aggregator must not require the consent of a supplier to work with their customer.

Revised Phase 1 Solution – The DRAI disagrees with the Revised Phase 1 Solution in its proposed form. However, the solution proposed above resolves many of these issues, and acts as a suitable interim solution prior to the Phase 2 solution, which would be compliant with Article 17 of the Directive and expanded upon in Article 22a & 22b of the draft Network Code for Demand Response (the "**NCDR**"), and Article 55a of the EBGL (amended through the NCDR as proposed by ACER).

It is worth noting, however, that any version of Phase 1 leaves suppliers facing the imbalance (their volumes are untouched, and they are not otherwise financially adjusted, which appears to be contrary to the requirements of the Clean Energy Package) and demand response providers instead repay into the imperfections pot a revenue estimated to be equivalent to the retail-tariff-based savings the customer has made from having reduced consumption. This appears to tackle the "double counting" concerns but does not resolve imbalance costs.

Q2: Do you agree with the description and analysis of the appropriate treatment of 'long-run' DSUs? Please explain your view.

DRAI believes, given the elegant solution of the supplier compensation mechanism that applies to all DSUs (subject to the refinements suggested above) there is no need to draw distinction between different DSUs with varying market characteristics. Indeed, we see no clear way to define, with any regulatory legitimacy, a basis for differentiation between DSUs. These "*long run*" & "*short run*" terms are useful colloquial terms but remain just that.

Similarly, terminology such as "*Base Load*" and "*Peaking Plants*" can be used as easy parlance when discussing the placement of units in this merit order as a result of the range of values they submit, but at no point, in either the Grid Code or the TSC, are these terms defined. Nor, in any documentation, is it specified that the values submitted under this framework could lead to differential treatment within the market. Similarly, the 'modes of participation' such as "*long run*" are simply a result of the market scheduler ordering units according to their technical and price offers. Units with low price offering will be called upon by the TSO for longer durations than those with higher costs - a logic which stands for both GUs and DSUs.

The Revised Phase 1 Solution, if not adopting the refinements set out above (specifically the use of the DAM price average), would have a serious negative impact on these low cost DSUs, undermining the viability of the associated end-users' continued participation in the market with their on-site generation assets. This would have several consequences to the system, including:

- a reduced financial incentive for on-site generation, thereby reducing capacity available to the system,
- a reduction in the volume of behind-the-meter generation visible to / controllable by the TSOs,
- a reduced incentive to be operating at times of system stress,
- no incentive for behind-the-meter generation assets to be curtailed at times of high renewable penetration, leading to greater levels of dispatch down of renewables

However, as observed, the use of an average DAM price suitably addresses this issue, without the need to introduce distinctions between DSUs.

Q3: Do you agree that incorporation of a supplier compensation payment between DSUs and suppliers would be an appropriate mechanism for addressing the 'missing money' problem for DSUs? Please explain your view.

No. What is described in the consultation paper as a "missing money" problem (not the usual meaning given to this phrase) is solved simply by providing energy payments to DSUs, as required by the Clean Energy Package. Supplier compensation payments have nothing to do with it.

The money that is really missing is due to the lack of perimeter correction for suppliers. Essentially, in the status quo, suppliers are receiving the benefits of the DSU's actions, instead of the DSUs and customers. Introducing the necessary energy payments ("Phase 1") solves the problem for DSUs, but still leaves suppliers with these undeserved windfall gains. Phase 2 resolves this issue by correcting suppliers' perimeters to remove the windfall gains.

It is the introduction of perimeter correction for suppliers in Phase 2 that leads to the need for supplier compensation payments: the payment directly relates to the volume of energy transferred in the perimeter correction.

Although supplier compensation payments are only needed in Phase 2, we do understand the rationalisation for introducing them in Phase 1: simply that they will offset some of the costs associated with not yet having introduced perimeter correction. Looking at the DSU's cashflows alone, there would be no difference between Phase 1 and Phase 2.

Q4

(A) For the revised Phase 1 solution, if it isn't possible to identify the affected suppliers, do you agree that it would be appropriate for the supplier compensation payment to be paid into the Imperfections Charge fund? Please explain your view.

We don't consider it "appropriate", but we can see why, pragmatically, it may be a workable solution for Phase 1.

(B) Do you consider that this will allow DSUs to compete on an equal footing, without any undue disadvantage or undue advantage, compared to generators? Please explain your view.

The SEM Committee seem to imply that the granting of energy payments would unduly advantage DSUs unless a compensation mechanism is brought in. This is incorrect, as granting energy payments simply puts demand response on par with generators, while any supplier compensation payment reduces the cost of the measure for all end consumers.

The SEMC also seem to suggest that one source of this undue advantage would be the lack of balance responsibility[2]. This is incorrect as, under the Grid Code, DSU aggregators are obliged to continually update the TSO with compliant values that reflect their real-time capability. Where a DSU is dispatched and their capability differs from the value to which they are dispatched, the DSU will update the TSO on their actual capability and the TSO will update their dispatch instruction accordingly. As such, contrary to the SEM Committee statement, Dispatch Quantity is an accurate proxy for Metered Generation and ensures a reasonable level of balance responsibility for DSUs, should the TSSU be removed.

This acknowledges that, contrary to the findings of the SEMC in SEM-20-027 & SEM-20-088, DSUs are currently exempt from balance responsibility, but not as a result of "*continuing to set DSU Metered Quantity equal to Dispatch Quantity"* as the SEMC state in the Consultation. Rather, the continued inclusion of the TSSU in the settlement algebra for a DSU participant does, in effect, fully negate the balance responsibility of the DSU participant. However, removing the TSSU would indeed expose DSUs to balance responsibility.

Assuming the SEM Committee are committed to achieving the Climate Action Plan targets for flexible demand, they should be incentivising end-consumers to become involved in demand response, by granting energy payments, therefore increasing the revenue of DSUs. **Q5: How do**

[2] Section 4.3 *"The SEM Committee is concerned that continuing to set DSU Metered Quantity equal to Dispatch Quantity and effectively exempting DSUs from balance responsibility is potentially inconsistent with Article 5(1) of the Electricity Regulation."*

you think the Supplier Compensation Price (PCOMP) should be calculated? What costs should be taken into account and what costs should be ignored? Please explain your view.

Any calculation must comply with the prescriptive requirements of Article 17(4) of the Directive, the FG DR, and the NCDR on the costs applicable for any compensation mechanism, and the DRAI strongly believes the Consultation should have set out the following parameters prior to proposing this question.

<u>*Article 17(4) of the Directive states:*</u>

*[…] "financial compensation shall be **strictly limited to covering the resulting costs incurred** by the suppliers of participating customers or the suppliers' balance responsible parties during the activation of demand response." […]*

<u>*Article 22b of the NCDR proposed by ENTSO-E & EU DSO Entity*</u>

*This compensation mechanism may encompass the reimbursement of **specific, verifiable additional costs directly associated with the service activation.***

<u>*Article 55A of the EBGL proposed by ACER through the NCDR*</u>

"3. The financial compensation pursuant to paragraph 2 shall:

a. *encompass the reimbursement of **specific, verifiable additional costs directly associated with the demand response activation** not already covered by the financial transfer pursuant to paragraph 1; and*
b. *include the **costs incurred by the supplier**."*

Furthermore, the suggestion in the Consultation to use a proxy for the retail price as a possible option is fundamentally flawed, given these parameters. The retail price in the SEM is made up of many charges, levies, tariffs, etc. as well as a supplier margin – none of which are incurred in the event of a non-delivery of energy. It is essential that only the costs incurred by the supplier as a direct result of the activation are included.

Therefore, the DRAI contends that <u>only</u> the wholesale price (using an average Day Ahead Price) should be used to calculate the Supplier Compensation Price.

It is also important that the benefits of demand response are taken into account when calculating this charge, as per Article 17(4) of the Directive, Article 55a (4) & (5) of draft EBGL revision, and Article 22(b) of the ENTSO-E & EU DSO Entity NCDR. Such benefits included in these articles are the lower wholesale prices as a result of DR activations, the lower network tariffs (especially due to units with on-site generation), lower system operation costs (especially due to units with on-site generation), and many more. While the DRAI understands the complicated nature of doing so, the SEM Committee could use a proxy value for these benefits based on historic data and apply this on a per MWh basis to the PCOMP, reducing it by the appropriate value.

In conclusion, the relevant provisions, both in draft and in force, are prescriptive in nature as to the costs that may be included in the compensation price. These do not include costs that have not been incurred as a result of the non-delivery of energy. Therefore, the DRAI contends that only the DAM price should be included as the starting point for the PCOMP, which should also be adjusted for the net benefits brought by DR on a per MWh basis.

Q6:

(A) Do you agree that a supplier compensation payment would have the correct incentive effect on long-run DSUs, as well as other DSUs, and would impose reasonable costs on end consumers? Please explain your view.

The DRAI does not believe the Revised Phase 1 Solution, as proposed in the Consultation, would have the correct incentive effect on long-run DSUs.

Under this solution, in the event that the supplier compensation payment is greater than the energy payment received by the DSU (which would happen regularly if using the retail price proxy) it would disincentivise Long Run DSUs from participating in the DSU. This is because they would be paying out more in Supplier Compensation Payments than they would be receiving in energy payments. In relative terms their earnings from DSU are low so a loss every hour of running would quickly diminish or even outweigh their capacity payment. This could have several negative results:

- It would almost certainly mean that long run DSU operators would stop participating in DSUs
- Having left the market, some of these operators may no longer have sufficient financial incentive to keep operating their on-site generation and so end its operation. This would lead to reduced capacity on the electrical system
- For those who chose not to stop running their on-site generation, but to continue outside of the market, there would be two negative outcomes:
    - They would not be incentivised to be operating at times of system stress, meaning a dangerous reduction in capacity at those times
    - They would no longer be available to be curtailed at times of high wind penetration, leading to more curtailment of wind

(B) Would [a supplier compensation payment] impose reasonable costs on end consumers? Please explain your view.

It is important to note that compliance with EU Law Provisions cannot be limited to only those that are judged to have "*reasonable costs*". Nonetheless, the costs associated with granting DSUs energy payments are indeed reasonable. The TSO's impact assessment was carried out during the high prices of 2022, and were expected to fall significantly – which they have done. This was noted in the Final Recommendation Report of Mod_02_23, where the costs were deemed reasonable.

As such, the cost reduction measures in the Consultation are unnecessary, and have no bearing on the need for compliance with EU Law Provisions.

Q7:

(A) Do you have any views on whether supplier corrections for non-consumed energy could be determined by voluntary agreement between the supplier and the DSU?

No, this would be a significant reversal of the progress the SEM have made in integrating demand response into the market. The EU have been pushing for a number of years for any Member State with such an arrangement in place to remove this requirement. Ireland should not be considering taking this step backwards. Specifically, it would be inconsistent with Article 17.3(a) of the Directive.

(B) Or by ex-post analysis of demand reduction dispatch decisions? Please explain your views.

This is more appropriate, assuming it describes Model 2 outlined in the Consultation.

Q8: Do you agree that it would be possible to categorise DSUs into long-run and intermittent DSUs by some other criterion, such as running hours, such that it would be possible to determine whether or not compensation for 'missing money' would be appropriate? If not, please explain why. How could such a test be implemented, in practice, and eligibility criterion enforced? Should such a test be used instead of, or together with, supplier compensation payments? Please explain your view.

DRAI believes, given the elegant solution of the supplier compensation mechanism that applies to all DSUs, subject to the refinements suggested above, there is no need to draw distinction between different DSUs with varying market characteristics. Indeed, we see no clear way to define, with any regulatory legitimacy, a basis for differentiation between DSUs. These "*long run*" & "*short run*" terms are useful colloquial terms but remain just that.

The DRAI is also concerned with the sentiment expressed in Section 3.5 of the Consultation, in which the SEM Committee appear to question the benefit to the system of "*long run*" DSUs, and their validity as Demand Response. As set out above, it is DRAI's position that these units provide valuable capacity and other services to the system via changes in their consumption.

As previously set out, the use of colloquial market parlance as a basis for any technical or regulatory distinction should not form the basis of any solution governing DSU energy payments. However, as observed, the use of average DAM prices suitably addresses this issue, without the need to distinguish between DSUs.

Q9: Do you agree with the description and analysis of the appropriate treatment of Capacity Payments and Capacity Charges? Do you think that Capacity Charges should be levied on non-consumed energy, e.g. by an adjustment to the supplier compensation price? Please explain your view.

The inclusion of non-energy charges that have not been incurred by suppliers as a result of demand response activations is contrary to the EU Law Provisions. Including capacity charges would be a major disincentive to explicit flexibility and therefore contradictory to other policy measures.

The models outlined in Section 4.1 are out of scope of DSU energy payments, and the DRAI does not see value in answering.

Q10:

(A) Do you consider that some form of baselining is needed?

This question is misleading, as it suggests there is no current form of baselining in place. DSU dispatches are currently baselined as per the methodology outlined in the Grid Code. While the DRAI recognises the identification by EY in their report on the capacity market of the need for refinement of this methodology, it is disingenuous to imply that there is currently no methodology in place.

(B) Would appropriate supplier compensation payment arrangements affect this?

The supplier compensation has no bearing on the requirement for refinements of the baselining methodology.

(C) If baselining is needed, do you have any views on how the baselining methodology should work? What should be taken into account in determining the baseline profile? Please explain your view.

Baselining is a complex issue and should be discussed bilaterally with industry and consulted upon in its own right.

Q11: How important is it to use sub-metering? Please explain your view.

Sub-metering is an increasingly important measure that allows previously inaccessible loads to participate in the market and become flexible. It enables sites with multiple processes/load resources to clearly identify the changes that relate to a demand response activation, helping with measurement and ultimately settlement – including in perimeter correction. Accordingly, it is being encouraged strongly by European Institutions, not least in the NCDR. The SEM Committee should work with market participants to adopt measures that enable the full use of sub-metering.

While it should not be mandatory and left to the discretion of the site and aggregator, it should be facilitated without delay to allow for easier perimeter correction when the SEM Committee move to implement such correction.

Q12: Would it be appropriate to use SCADA data for the purpose of setting DSU metered quantity? How could this arrangement work in practice? Please explain your view.

DRAI agree with this change. Furthermore, this SCADA data should be used in place of the majority of EDIL declarations.

Q13: Do you consider that on-site generation could be accommodated in the SEM through the arrangements for Aggregated Generator Units? Are there reasons why it makes more sense to use Demand Side Units? Please explain your view.

AGUs and DSUs are fundamentally different participation methodologies. DSUs allow final consumers to offer their flexible demand into the market, either directly or through an aggregator. Such flexibility can be achieved through various forms, including on-site generation, as well as demand reduction. A key characteristic of a DSU is that it does not intend to inject electricity into the system (although there is scope for this under EU Law Provisions), but rather reduce its withdrawal by these means. All current DSUs operate on this premise.

AGUs, on the other hand, are currently not implemented into existing legislation in ROI. If introduced, it would be implicit that they would inject into the system and be paid accordingly. The difficulty of adopting this participation methodology for demand response is that measuring a site's response as its injection (without assessing its demand reduction) would render nearly every DSU dispatch as null.

Furthermore, additional requirements on monitoring, testing and communication would create significant burden preventing the existing participant from providing valuable services to the TSO. Considering that DSU support is still not complete, and the type of unit is not fully implemented in the TSO's systems after more than a decade of successful operation of the technology, a requirement to force end-customers to provide demand management services via AGU would be disadvantageous and against the spirit and wording of the Clean Energy Package.

Q14: Are there any other issues relating to the treatment of DSUs in the SEM, which the SEM Committee should consider when implementing a revised Phase 1 solution? If so, please explain these issues.

The DRAI note that there is no mention of the lack of energy payments to DSUs since 2020, as required by the provision set out by the Clean Energy Package. The recent judgement from the High Court of Ireland in the Judicial Review brought by GR Wind, Energia, and others [Record No. 2022/507 JR] has confirmed the obligations placed on the SEMC under the provisions of Regulation (EU) 2019/943 have been applicable since then.

As such, we ask that the SEM Committee begin to engage with the industry on this matter.

Q15:

(A) What are you views regarding negative demand response?

Assuming by "negative demand response" the SEM Committee is referring to negative demand reduction - Section 3.6 of the Consultation Paper sets out the practices of some DSUs in a way that, to a reader that may not understand the commonality of these practices across the industry, would make it seem that these market rules are unique to DSUs. The submission of negative decremental bid prices, where cost reflective as mandated by BCOP, and the concept of a DSU being paid to not reduce demand should be seen as no less of a valid market outcome than a generator being paid not to generate, which they often are for various reasons; both are perfectly rational market outcomes in certain scenarios. As such, any change in market rules regarding Decremental Bids should be applied to all units.

Furthermore, this negative demand response has been well documented and discussed, including in information note SEM-18-158. As stated in the Final Recommendation Report of Mod_02_23, the Market Monitoring Unit - operating as a part of the Regulatory Authority - has reviewed these behaviours, well in advance of either consultation on granting DSUs energy payments. The operation of some DSUs, in line with market rules that apply to all units, is in response to the market incentives for all units to have low cost, long duration characteristics.

(B) Do you consider the supplier compensation payment arrangement will work for negative demand response?

The supplier compensation should have the capability of flowing from the supplier to the service provider in the event of negative demand response. The supplier will benefit from the consumer's increased demand without having had to source the energy, assuming the supplier bills the consumer for this demand (which is expected). Transferring this revenue via reverse supplier compensation means that it can offset the customer's payment to the supplier for the additional energy. The current ACER draft of the NC DR is explicit that the financial transfer element of any supplier compensation regime must be bidirectional.

(C) Do you think there is any potential for perverse outcomes and undue discrimination between customers? Please explain your view.

No, there are no perverse outcomes from market participants performing actions as dictated by the market rules in place for all units.

Q16: How should shutdown costs for IDSs be accurately reflected in the COD for DSUs? Please explain your view.

The shutdown cost for a DSU is governed by the Bidding Code of Practice. All market participants are required to comply with this legislation. There is no differential treatment of market participants based on their technology type. Any additional requirements would stifle the current operation of aggregated units and prevent growth of demand response (which is a goal set by the Government to the TSO and DSO).

From the point of view of aggregators, the composition of a DSU changes in real time. Additionally, multiple IDS can be activated to provide response, with varying and variable response during the demand response event. The so called "portfolio effect" allows the aggregators to provide the required response. Due to the fluid nature of a DSU's response, the shutdown costs could change every minute.

At the moment, the way to submit shutdown cost is purely manual, not user friendly and prone to delays caused by the mandatory use of an outdated and insecure internet browser. Even if shutdown costs were re-assessed more frequently than today (when a real change of shutdown cost is identified and documented), there is no technical capability on the market operator's side to receive such information.

A conventional powerplant does not receive different startup cost, if they are instructed to sync at the Minimum Generation value, or when they receive instruction to deliver Maximum Generation. A fair and transparent treatment of technology types of all market participants should be sustained.

When considering cost calculations for an aggregated unit, an aggregator must treat their customers fairly by accounting for the startup and shut down costs of all IDS. Except in the case of a DSU with a single IDS, it's not possible to forecast which IDS will be instructed to provide the required response.

Q17: How should decremental bid prices to reduce demand reduction be calculated? Under what circumstances do you consider that decremental prices could be negative? Please explain your view.

The calculation of decremental bid prices is determined by the Trading & Settlement Code for all units. Many unit types regularly submit decremental bids, such as older baseload generation (which prefer to remain at a constant generation load), as well as Waste to Energy (WtE) plants (which operate regardless of market participation or system conditions).

The rules that apply to all units are deemed reasonable by the DRAI and require no change.

Q18: Do you agree that the Grid Code requires DSUs to declare an availability of 4 MW or above on a regular basis? If not, please explain why.

The Grid Code states that DSUs are "*an Individual Demand Site or Aggregated Demand Site with a Demand Side Unit MW Capacity of at least 4 MW. The Demand Side Unit shall be subject to Central Dispatch*."

This does not include any requirement for DSUs to declare an availability of 4 MW or above on a regular basis.

Q19: Do you agree that the Grid Code requires DSUs to round down their declared availability to the nearest MW? If not, please explain why.

The DRAI does not accept this interpretation of DSUs' binding obligations regarding availability declarations under the Grid Code.

An important contributing factor to this issue is the fundamental system limitation with the EDIL system, which can only accept integer values for availability declarations. This flawed user interface restricts market participants' ability to provide good quality declarations of real-time availability. The DRAI and others have raised this concern for multiple years, and explained its high materiality, especially for small units. While the TSOs have stated that they are exploring changes to the EDIL system to consider enabling the submission of declarations to a higher degree of accuracy, this does not seem to have been prioritised for delivery in any of the TSOs' work plans or roadmaps.

In certain circumstances, applying an overly simplified rounding logic to determine an appropriate declaration would result in this TSO system flaw unfairly manifesting material impact on the market participation of small units. Nowhere in the Grid Code is such a specific requirement to round declarations to the nearest integer specified. Contrary to this, it is important to note that throughout many aspects of the Grid Code, an applicable tolerance of at least 1 MW is enshrined.

The DRAI is satisfied that aggregators are meeting their binding Grid Code obligations to use *reasonable endeavours* to ensure their EDIL availability declarations reflect what each DSU could achieve at the relevant time, within applicable tolerances and that it is acting in accordance with *Good Industry Practice*.

General comment regarding Consultation questions

The DRAI strongly feel many of these questions are considerably out of scope of DSU energy payments. We do not feel it is appropriate that a significant portion of the Consultation questions address minor points such as rounding and availability declarations, when a matter of greater importance is being delayed – significantly impacting the DSU industry.