Demand Side Units: A Revised Phase 1 Solution for Energy Payments and Other Issues

Proposed Decision Paper

SEM-26-017

31 March 2026

EXECUTIVE SUMMARY

In 2019, the SEM Committee issued a decision regarding an interim solution that provided energy payments to be made to Demand Side Units (DSUs) during "Reliability Option events" when Difference Payments are due. The decision was implemented by Trading and Settlement Code Mod_17_19.

A further decision paper in 2022 set out a phased approach towards an enduring solution providing energy payments to DSUs at all times, not just during Reliability Option events. In light of the timelines for implementing the necessary systems, the SEM Committee decided, subject to impact assessment, to proceed with a "Phase 1" solution that does not require "perimeter correction". It was recognised that this temporary solution would result in a degree of double counting, in that demand reduction would result in both savings in purchase costs for the supplier as well as energy payments to the DSU. The subsequent impact assessment estimated a cost of approximately €56m per year, of which €52m was due to payments to "long-run" DSUs, which provide demand reduction most or all of the time. More than putting DSUs on an equal footing with other resources in the SEM, this €52m per year represented double payment to DSUs and demand reduction customers, the cost of which would have to be funded by all end customers via the Imperfections Charge on all suppliers, without resulting in any beneficial change in behaviour.

In 2024, the SEM Committee consulted on a revised temporary solution for making energy payments to DSUs before a system for perimeter correction is implemented, together with several other issues concerning DSUs in the SEM. A 'Revised Phase 1 Solution' was discussed whereby a 'supplier compensation payment' is made by DSU aggregators into the Imperfections 'fund', which otherwise would fund the double payment of demand reductions.

Fifteen responses were received, which are summarised and discussed. The SEM Committee makes a number of proposed decisions, including to proceed with the Revised Phase 1 Solution. It is shown that the supplier compensation payment is not a mechanism just for reducing the cost of energy payments to DSUs but is necessary to ensure that demand reduction is appropriately incentivised and dispatched and to ensure it competes on an equal footing with generation, as required by EU Regulation 2019/943. It is shown that the approach obviates the need to distinguish between long-run and 'intermittent' or 'short-run' DSUs. It is shown that customers providing long-run demand reduction and their aggregators and suppliers should be financially neutral, while the ‘missing money’ issue for aggregators with intermittent DSUs and their customers is addressed. Addressing this missing money issue should improve DSU performance and promote additional demand reduction at times when it is most beneficial. The supplier compensation payment requires the determination of a Supplier Compensation Price, which will be the subject of a consultation running in parallel with this proposed decision.

A number of other issues including baselining, sub-metering and SCADA, availability declarations, bidding and Aggregated Generator Units are discussed. The SEM Committee proposes that these issues are reviewed and resolved in a number of separate initiatives.

A consultation paper on the methodology for determining Supplier Compensation Price will be published shortly. In the meantime, the SEM Committee is publishing these proposed decisions and will conclude on these and the Supplier Compensation Price methodology together.

Table of Contents

Glossary of Terms and Abbreviations

Abbreviation or Term	Definition or Meaning
ACER	Agency for the Cooperation of Energy Regulators
BCOP	Bidding Code of Practice
BRP	Balance Responsible Party
COD	Commercial Offer Data
CRU	Commission for Regulation of Utilities
DSU	Demand Side Unit
EDIL	Electronic Dispatch Instruction Logger
ENTSO-E	European Network of Transmission System Operators (Electricity)
EU	European Union
NCDR	Network Code for Demand Response
IDS	Individual Demand Site
MDP	Meter Data Provider
MMU	Regulatory Authorities' Market Monitoring Unit
MPRN	Meter Point Reference Number
PIMB, QD, QM, FPN	Imbalance Price, Dispatch Quantity, Metered Quantity, Final Physical Notification. (As defined in the TSC.)
PCOMP, PSUPP	Supplier Compensation Price, Supplier Purchase Price.
RAs	Regulatory Authorities
RO	Reliability Option
SEM	Single Electricity Market
SEMO	Single Electricity Market Operator
TSC	Trading and Settlement Code
TSO / DSO	Transmission / Distribution System Operator

1. Introduction

The SEM Committee consulted in 2024 on a revised solution for making energy payments to Demand Side Units (DSUs), together with several related issues concerning DSUs in the SEM.

This paper gives an overview of the issues discussed, summarises and discusses the responses received, and lists the SEM Committee's proposed decisions.

The structure of the paper is as follows:

- Section 1: is this introduction;
- Section 2: gives background to DSUs in the SEM, including previous consultations and decisions;
- Section 3: summarises the comments received;
- Section 4: gives the SEM Committee's response to the comments received;
- Section 5: sets out the SEM Committee's proposed decisions; and
- Section 6: sets out next steps.

There are a number of appendices:

- Appendix A: lists the parties that responded to the consultation;
- Appendix B: lists consultation questions;
- Appendix C: discusses additional details for the models described in the consultation;
- Appendix D: discusses Supplier Compensation Price methodologies;
- Appendix E: discusses the impact assessment; and
- Appendix F: lists relevant documents.

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2. Summary of the Consultation

The SEM Committee published a consultation paper[1] in 2024 (the "Consultation Paper") seeking views on a "Revised Phase 1 Solution" for providing energy payments to DSU aggregators and on a number of other issues relating to DSUs in the SEM.

2.1. Background

The Consultation Paper described the background to the consultation as follows.

In 2019, the SEM Committee issued a decision[2] regarding an "interim solution" that provided for energy payments to be made to DSUs when Difference Charges are due, i.e. when there is a "Reliability Option (RO) event" and market prices are above the RO Strike Price[3]. As an interim solution, there was no "perimeter correction"[4] and instead the costs of the energy payments were to be paid by all suppliers on some equitable basis, which in the resulting Trading and Settlement Code Modification[5] was defined to be through the Imperfections Charge. It was argued that, given that the costs would be incurred only during relatively infrequent RO events, the impact on the Imperfections Charge would be limited.

In November 2022, the SEM Committee issued a further decision paper[6], setting out a phased approach towards an enduring solution to provide DSU energy payments at all times, and not just when market prices are above the RO Strike Price. The enduring "Phase 2" solution includes a system for perimeter correction, whereby the supplier of an Individual Demand Site (IDS) is required to purchase the "non-consumed energy" that is sold back to the system as demand reduction by the DSU

[1] "Demand Side Units: A Revised Phase 1 Solution for Energy Payments and Other Issues: Consultation Paper", SEM-24-046, 23 August 2024.

[2] "Capacity Remuneration Mechanism DSU Compliance with State Aid: Decision Paper", SEM-19-029, July 2019.

[3] An "RO event" refers to when market prices are above the RO Strike Price.

[4] "Perimeter correction" refers to the process of identifying the suppliers of the customers effecting the demand reduction of a DSU. Instead of the customers' metered demands, these suppliers are then deemed to have supplied the demand the customers would have taken had the demand reduction not been instructed, i.e. the metered demand plus the 'non-consumed energy'.

[5] "Final Recommendation Report: Mod_17_19."

[6] "Enduring Solution to Enable Energy Payments in the Balancing Market for DSUs – Decision Paper", SEM-22-090, 25 November 2022.

aggregator. The supplier then charges the customer at the IDS for this non-consumed energy, and the customer is likely to then require compensation from the aggregator. In light of the timelines for implementing the system necessary to identify relevant suppliers and determine perimeter correction quantities, the SEM Committee decided also, subject to impact assessment, to proceed with a temporary "Phase 1" solution which does not include perimeter correction. It was recognised that this interim solution would result in 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, the costs of which would have to be funded by all end customers via the Imperfections Charge on all suppliers.

The subsequent impact assessment, undertaken by the TSOs/SEMO as part of a TSC Modification Proposal[7], estimated a cost of €56m per year, of which approximately €52m was due to payments to “long-run” DSUs. More than putting DSUs on an equal footing with other resources in the SEM, this €52m per year represented a double payment to DSUs – more specifically to DSUs and their customers combined – who would benefit both from the saving in supply purchase costs and from the energy payment to DSUs, with the double payment being funded by other end customers.

2.2. Missing Money Problem

The Consultation Paper discussed different modes of participation for DSUs, which have been referred to as “long-run” and “short-run” or “intermittent” DSUs. These are not intended as formal definitions but are analogous to the terms “baseload” and “peaker” often applied to generation.

It was recognised that, in the absence of energy payments, intermittent DSUs may suffer a “missing money” problem[8], which arises if a high marginal cost DSU is dispatched when the Imbalance Price is high but, in the absence of energy payments

[7] “Final Recommendation Report: Mod_02_23 DSU Energy Payments”, SEMO, 22 February 2023.

[8] As discussed in the consultation paper, the term “missing money” is normally used in the context of capacity markets to describe the situation where wholesale market prices do not reach levels high enough to reflect the costs of an efficient level of generation capacity. In the context of demand response, it describes the situation where, at any given time, the customer’s saving in the cost of purchasing from supplier may be insufficient to cover the costs of efficient demand reduction.

at the high Imbalance Price, realises only savings in the (possibly) lower costs of purchasing from the supplier[9]. The problem was recognised as being the sharing of some of the benefit of the demand reduction in the form of an unanticipated gain for the supplier.

It was noted that long-run DSUs, typically comprising low marginal cost on-site CHP generation, where the generation is always in merit and so runs at all times to meet on-site demand, does not suffer from a missing money problem, with the savings in the cost of purchasing from the market via a supplier more than covering the cost of running the generation. These cost savings are the main rationale for using such generation[10].

2.3. Models

The Consultation Paper set out four hypothetical models for compensating demand reduction:

Model 1 (No DSU Energy Payments): The main compensation for the activation of demand reduction accrues from saving in supplier costs, resulting in the missing money problem described above;

Model 2 (DSU Energy Payments): The DSU is paid energy payments, while the supplier is required to purchase the non-consumed energy. The supplier will seek to recover the cost of the non-consumed energy from the customer. The customer will then require compensation for the cost of the non-consumed energy out of the energy payments received by the DSU aggregator.

Model 3 (DSU Energy Payments with Supplier Compensation): To avoid the supplier having to bill the customer for energy the customer hasn't consumed, and the customer having to recover these costs from the DSU aggregator, a payment is made from the DSU aggregator to the supplier, bypassing the customer. (Note that a bilateral agreement is not necessary for this payment to be made, with the payment being made under the auspices of the TSC via the Market Operator.)

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[9] Most obviously, a supplier supplying a customer at a flat rate may be supplying at a profit when the Imbalance Price and/or DAM price is low but at a loss when the Imbalance Price and/or DAM price is high.

[10] In the case of CHP, the generation meets a heat demand as well as an electricity demand.

Revised Phase 1 Solution: Models 2 and 3 require the explicit identification of the supplier(s) of demand-reducing customers and determination of the associated demand reduction quantities, which the SEM Committee understands to be a complex process. Hence the Consultation Paper put forward a "Revised Phase 1 Solution" whereby this would be done implicitly rather than explicitly. Compared to Model 3, the cashflow from the DSU aggregator to the market operator would be exactly the same, putting the DSU in exactly the same financial position, but the cashflow to the supplier would be at the Imbalance Price (PIMB) rather than a 'Supplier Compensation Price' (PCOMP).

The Consultation Paper noted that for DSUs which are giving demand reduction most if not all the time, PCOMP should approximately balance the savings in the costs of purchasing through the supplier such that the cost to end customers via the Imperfections charge on suppliers would be negligible. This would be consistent with the observation that there is no missing money for these DSUs and that the payment of explicit energy payments does not result in any change of behaviour which is beneficial to the system. Importantly, the addition of an appropriately set PCOMP cashflow would ensure that there is no double counting of demand reduction through both energy payments to the DSU as well as savings for the customer of purchasing through the supplier.

The Consultation Paper also noted that for short-run or intermittent DSUs demand reductions taking place at times when PIMB is greater than PCOMP are not counter-balanced/averaged out by demand reductions taking place at other times when PIMB is less than PCOMP. Hence there would be some double counting through both energy payments to the DSU and supply purchase cost savings for the customer.

In all but Model 1, i.e. no energy payments, energy payments to DSUs address the missing money problem, and avoid the possibility of high-cost DSUs being dispatched even when the savings in supply purchase costs do not cover the costs of effecting the demand reduction.

2.4. Other Issues

The Consultation Paper also raised and invited views on a number of related issues:

(i) how capacity costs should be treated in the various models, and in the Revised Phase 1 Solution;

(ii) baselining;

(iii) sub-metering and the use of SCADA data;

(iv) the possible impact of dynamic retail tariffs;

(v) Grid Code provisions concerning availability declarations;

(vi) bidding of DSUs, including the treatment of IDS shutdown costs and appropriateness of negative decremental prices, where DSUs are paid *not* to make demand reductions; and

(vii) the suitability of using Aggregated Generator Units rather than DSUs in some circumstances.

2.5. Network Code for Demand Response

On 7 March 2025, after the publication of the Consultation Paper, ACER published its recommendation to the European Commission for the network code on demand response (NCDR), including a draft network code and draft amendments to the Electricity Balancing Guideline (EBGL)[11].

In a new Article 55A, the amended EBGL provides for financial transfer and compensation. In particular:

(i) Article 55A(1) relates to "*financial transfer*". This is mandatory for all Balance Responsible Parties (BRPs) for which a "correction" is calculated under Article 54(4)(1a)[12]. This transfer must be based on a formula, and the provision requires that financial transfer mechanism does not a create undue barrier to entry, places appropriate incentives, and aims to reflect the cost of energy sourcing.

(ii) Article 55A(2) to (5) relate to "*financial compensation*" established pursuant to Article 17(4) of EU Directive 2019/944. Under Article 17(4), compensation is optional and payable to market participants directly affected by demand response activation. Under Article 17(4), compensation must not create a barrier to entry and is limited to the costs incurred by the supplier during the demand response

[11] "Recommendation No 01/2025: Network Code on Demand Response", ACER, 7 March 2025.

[12] The reference in the proposed Article 55A should be to Article 54(4)(a1).

activation. Under Article 55A financial compensation is to "*encompass the reimbursement of defined costs associated with demand response activation*" which costs "*may include, but are not limited to, costs due to the rebound effect and costs of socialised charges which increase due to demand response activation*."

3. Summary of the Consultation

A total of 15 non-confidential responses were received. The respondents are listed in Appendix A.

3.1. DSU Cashflow Models (Question 1)

The Consultation Paper asked respondents whether they agreed with the description and analysis of models for compensating demand response. Eleven respondents commented.

One respondent said that the models set out, at a high-level, the different methods for paying demand response, including the current and potential models. It said that a consequence of being high-level was that "*simplification ... brings the risk of not accurately reflecting the operation of the market or the behaviour of participants, particularly with regards to ... the missing money issue*". It said further that "*suppliers have no way of knowing when a high-cost DSU will turn down, and therefore are likely to purchase the power in the ex-ante markets before spilling into the balancing market (BM) in the event that the power is not consumed by the final customer*", whereas "*it is far more likely that high-cost DSUs will only be in called upon through the balancing market as prices rise in response to unexpected scarcity.*"

Two respondents agreed with Model 1 and agreed with "*the recognition of the need to change to one in which DSUs are actually compensated equal to generators for the energy provided to the system*". They agreed also with Models 2 and 3, and said, "*these are the only models in which the SEM would be fully compliant with the EU Law Provisions*". However, they objected to the Revised Phase 1 Solution, arguing that it "*attempts to implement the optional measure as set out in Article 17(4) of the Directive and expanded upon in Articles 22a and 22b of the draft NCDR, and Article 55a of the EBGL (amended through the NCDR as proposed by ACER)*". One of the respondents said the SEM Committee was "*proposing an indirect ... one way compensation mechanism from DSU service providers to suppliers based on a proxy for the average retail energy price*" when "[the] *obligations require a direct, two-way measure that is limited to the costs incurred during the activation*". The second of the two respondents proposed a solution that principally addressed the setting of PCOMP (and is discussed later) that it said would resolve many of these issues.

Two other respondents noted that in Model 1 there is a saving to the supplier but commented that it was not acceptable as "*it does not cover the cost of providing the service*"; they noted that Models 2 and 3 require "*identification of specific metering of the reduction at each customer and DSU*" and that "*this has already been identified as very difficult and costly to implement*". They further commented that Model 2 is not acceptable as "*it burdens the customer and is difficult to implement*", while, in Model 3, "*the requirement for the DSU to pay 'compensation' directly to the supplier is not accepted as a justifiable need*" and that "*the surrogate value for the loss of revenue from the customer ... is not an amount that the DSU can afford since it is not included in the Offer price*". Regarding the Revised Phase 1 Model, these respondents said that they agreed to the customer buying "*grid demand from the supplier and the supplier ... from the Wholesale market*" and "*the DSU get*[ting] *paid for its energy provision*". However, they said they "*have an issue with any 'compensation' that may be paid to back to the imperfections charge fund by the DSU*", saying further that "*the DSU can not afford this as the Offer price only covers the cost of the service provision*".

Two respondents commented on customers sharing costs with the DSU aggregator in Model 3 and the Revised Phase 1 Solution. One said this misrepresented a key point and that "*DSU aggregators would not seek any payments from participants, regardless of their savings, and always shares the revenue earned*". The second said "... *systems* [to show the actual reductions on specific IDSs] *do not currently exist for the majority of IDSs. Because of this the proposed Phase 1 suggestion that the customer shares the saving in supplier charges with the DSU is unlikely to be workable.*"

One respondent said it welcomed the analysis, and said it "*agrees with the revised Phase 1 proposal to refine the compensation model for DSUs to address the double-counting issue that has allowed both DSUs and suppliers to benefit from the same demand reduction*" and "*the analysis highlights the significant impact of long-run DSUs which have increased the burden of Imperfections costs on consumers and underscores the need for adjustments to the existing compensation structures*". Another said the analysis "*is welcome and appears reasonable overall*" but that "*a supplier with no DSUs on its meter points would not get much financial benefit from the arrangement and would instead face extra costs as a result*". Regarding the

Revised Phase 1 Solution, a third said it "*removes double counting of demand reduction whereby SEMO is not making energy payments to DSUs as well as suppliers, addressed through the payments by DSUs to the imperfections pot*", albeit highlighting some risks associated with the implementation.

One respondent said that it did not have a third party electricity supplier and that "*any rule change should accommodate DSUs that procure power for their own use, where the site has no contract with a 3rd party Supplier, and therefore does not contribute to the missing money problem.*"

One respondent said that to fully understand the nuanced implications for networks and the retail market further engagement would be beneficial.

3.2. 'Long-Run' DSUs (Question 2)

The Consultation Paper asked respondents whether they agreed with the description and analysis of the appropriate treatment of 'long-run' DSUs. Ten respondents commented.

One respondent said that it "*agrees that there is a potential issue with "long-run" DSUs receiving energy payments paid for via imperfection charges without PCOMP*" and that "*that consumers face additional costs for no particular benefit.*"

A second respondent said "... *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 respondent said further, "*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.*".

A third respondent said that "*if it is the intent that the net outcome of applying the same solution as for all other DSUs would result in "long-run" DSUs not receiving additional revenue ... points we raise in response to other questions need to be* *considered in relation to the appropriate level of the Supplier Compensation Price to reflect the cost and market revenue of the 'long-run' DSU.*"

A fourth said "*the general treatment appears to be reasonable, however it is not clear how this would work in practice*" and that "*this approach does also not account for non-energy consequences, in particular network charges*".

On categorising DSUs, a number of respondents said they agreed with making a distinction between long and short-run DSUs.

One respondent said it supports the distinction between long-run and short-run DSUs, and that "*distinguishing between operational roles of long-run and short-run DSUs necessitates tailored compensation mechanisms to ensure that DSU payments are proportionate to the actual system value provided*" and that it "*support*[s] *the RAs' proposal to limit eligibility for energy payments only to DSUs that comply with the definition of demand response"*.

Three respondents said they "*agree with the analysis on long-run DSUs*". One said they "*provide consistent demand reduction*" and "*do not face the same 'missing money' issues as short-run or 'intermittent' DSUs*". All three said "*it is vital that any compensation mechanism does not inadvertently penalize long-run DSUs or disincentivise their continued operation*". One said further that it "*welcomed categorising DSUs into 'long-run' and 'intermittent'*", while the other two said *"the analysis pushes to make distinction between the formats of 'long-runs' and 'intermittent' DSUs*" and "*accepts this approach, insofar as they operate in a different mode and the commercial Offers made to the market are significantly different*".

Lastly, one respondent questioned whether there is a requirement "*to differentiate between a 'long run' DSU and 'short run' DSU, in respect to its role as an* [Meter Data Provider]", while another said "*the persistent use of the term 'long run DSU' is concerning, as the SEM Committee appears to be using it to draw distinctions between units that do not exist*" and that "*growing narrative that delineates between 'modes of participation' of units in the SEM is concerning and fundamentally incorrect*". This respondent also expressed concern that "*the SEM Committee appears to question the applicability of the definition of demand response to 'Long Run' DSUs*" and cited the Directive as defining demand response as "*the change of* *electricity load by final customers from their normal or current consumption patterns in response to market signals*".

3.3. Missing Money and Supplier Compensation (Question 3)

The Consultation Paper invited respondents to comment on whether the supplier compensation payment would be an appropriate mechanism for addressing the missing money problem. Ten respondents commented.

One respondent gave "*support for a refined, transparent, and well-monitored compensation mechanism to address the 'missing money' and 'double counting' issues and reduce the impact of the Imperfections Charge on consumers*" and that it "*agrees that the Supplier Compensation mechanism proposed in this consultation can help address the 'missing money' issue for DSUs that face higher costs for reducing demand during peak periods*". A second respondent said it "*sees merit in introducing PCOMP in theory*" although to "*fully understand how PCOMP would work to properly incentivise high cost DSUs while ensuring that long-run DSUs are not over-compensated*" it would need to "*assess a detailed proposal for how PCOMP would be calculated*".

A third said it did not agree supplier compensation payment would solve the missing money problem and said "*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*".

A fourth said "*the incorporation of the supplier compensation payment reduces the net cost of granting DSUs energy payments but does not address the missing money problem for DSUs*" and that "*nor does it resolve imbalance costs or leave suppliers balance responsible*". Two other respondents said they recognised that "*compensation directly from DSU to Supplier is currently not possible*" but also that this "*does not reflect the advantage to other suppliers due to the balancing price being kept down through the DSU dispatch, instead of other more expensive generation being used*". They said the calculation of compensation is an area of concern as the full methodology hasn't been defined, and that the payment "*appears to be an effort to reduce the cost to the suppliers and move the assumed benefit from the customer via the DSU back to the supplier*".

One respondent did not agree that supplier compensation "*is a viable approach to address the 'missing money' problem*" and that its "*understanding was that the aim was to create a level playing field for DSU's with other generators in the market, by removing distortion caused by suppliers inadvertently benefiting from DSU demand reductions*".

Another respondent said it thought that "*this* [supplier compensation] *may be suitable as an interim solution to achieve an immediate saving in imperfections charges and to provide a stronger incentive for short-run DSUs*". It said that "*there is a risk of undesirable effects if it is extended*" and that "*all energy generation should be accounted for and allocated to a wholesale unit where it is generated and to another wholesale unit where it is consumed"*.

One respondent proposed, "*any rule change should accommodate DSUs that procure power for their own use, where the site has no contract with a 3rd party Supplier, and therefore does not contribute to the missing money problem*".

One respondent said it would like to understand the data requirements.

3.4. Supplier Compensation via the Imperfections Fund (Question 4)

The Consultation Paper invited respondents to comment on whether it would be appropriate for supplier compensation payments to be paid into the Imperfections Charge fund, and that this would allow DSUs to compete on an equal footing compared to generators. Nine respondents commented.

One respondent said that it "*acknowledged the supplier compensation payment proposal as an appropriate mechanism for addressing the double counting of demand reduction*" and that "*the Supplier Compensation payment should be paid into the Imperfections Charge fund to offset the additional energy payments being paid out in the absence of a solution to identify the affected suppliers.*"

One respondent said that it maintained its position from its response to one of the previous consultations that "*paying supplier compensation into the Imperfections Charge fund should only be considered an interim solution*". It said, further, that it is "*crucial that the revised Phase 1 solution is implemented efficiently to ensure that consumers benefit from improved DSU performance and availability, which are* *critical to energy security*", and urged SEMC "*to review the impact of the revised solution thoroughly, confirming that the double-counting issue has been resolved before moving to Phase 2*". It said that, while the "*consultation acknowledges the importance of mitigating consumer cost increases*", the Revised Phase 1 Solution, "*falls short by not providing a concrete proposal for smoothing these costs over time*". A second respondent said "*this is acceptable as a short term* solution" but that "*the compensation for the DSU will be based on what is ultimately an arbitrary price, the supplier compensation price, which is based on some sort of average calculation rather than reflecting the reality of the particular situation.*"

Another respondent said it agreed "*that the inability to identify affected suppliers would require payments to and from a general pot (in this instance, the Imperfections Charge fund) to implement energy payments to DSUs.*" It said also that "*changes may need to be made to ensure that DSUs are genuinely balance responsible as other participants are required to be*" and that "*Baselining (currently non-existent) and detailed metering (dispatch quantity currently set to metered quantity) to demonstrate that demand reduction has actually taken place should be implemented alongside a revised phase 1 solution on energy payments.*"

Two respondents said "*the revised Phase 1 solution of utilising the Imperfection Charge fund would be acceptable*" but that they had reservations that "*DSUs shall not have the financial ability to cover production costs and the compensation payment without increasing its Offer price to the market.*". They said "*the alternative would be to obtain a value from the IDS, which would require adjustment of contractual terms*" and that "*this would likely drive IDSs away and place an unwanted risk to the ability of DSUs to fulfil their Capacity Obligation*." Another respondent said it "[does] *not support the proposal for 'intermittent' DSUs to pay the supplier compensation payment into the Imperfections Charge fund*" and that it "*propose[s] that the compensation payment for 'Long-Run' be made equal to any energy payments calculated.*"

One respondent said it "[didn't] *consider it 'appropriate'*" but said it could "*see why, pragmatically, it may be a workable solution*". It said, "*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.*" Another respondent said that using the Imperfections Charge fund was not acceptable as it "*constitutes an indirect payment by DSUs to all suppliers; has no way of determining the specific, verifiable costs incurred as a result of an activation; appears to precede the Financial Transfer Mechanism (such as perimeter correction) required by Article 55a of the Draft EBGL; leaves supplier's savings intact; and cannot flow in both directions (from service provider to supplier and vice versa).*" It said that these make it non-compliant with EU Law. Regarding "*the indirect nature of the Imperfections Charge fund*", it said that "*the compensation mechanism shall only be applicable for suppliers of participating customers (or their BRPs), rather than all suppliers.*" It said also that "*Article 55A of the proposed EBGL text ... states the need for a financial transfer mechanism prior to the compensation mechanism as proposed in the Consultation*" and that "*this financial transfer mechanism appears to be directly referring to a perimeter correction model, in which imbalance volumes are correctly attributed, and a financial payment is made accordingly*."

3.5. Calculating Supplier Compensation Price (Question 5)

The Consultation Paper invited respondents to comment on how the Supplier Compensation Price (PCOMP) should be calculated, and to comment on what costs should be taken into account and what costs should be ignored. Nine respondents commented.

One respondent made a number of suggestions to "*ensur*[e] *that PCOMP reflects the true market value of demand reduction*". Suggestions included: a "*market-based approach, such as using an average price that tracks the retail price*" that "*could factor in elements like capacity charges and adjust dynamically based on changes in demand and market conditions*"; and "*a rolling average of DAM baseload or mid-merit prices*". It said that time of use pricing, while "*improv*[ing] *the accuracy of payments with periods of high demand*", might be of limited value. It commented that "s*hort-run DSUs already respond to market signals and are inherently incentivised to be available during peak times*" while "*long-run DSUs, which operate continuously, are more likely to respond to dispatch instructions rather than market price fluctuations.*"

One respondent said that "*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*". It cited Article 17(4) of the Directive as stating, "*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*". It also cited Article 22b of the proposed NCDR as stating "*this compensation mechanism may encompass the reimbursement of specific, verifiable additional costs directly associated with the service activation*" and the proposed Article 55A of the EBGL as stating "*financial compensation ... 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.*" It commented that "*the suggestion in the Consultation to use a proxy for the retail price as a possible option is fundamentally flawed, given these parameters*". A second respondent made similar points and said it contended that "*only the wholesale price (using the Day Ahead Price) should be used to calculate the supplier compensation price*".

These two respondents proposed measures they said are "*on a workable interim basis ... to prevent further delay to the full and equitable access of DSUs to energy payments*". They expressed concern about calculating the supplier compensation price *"as an administratively determined proxy for the average retail price".* Instead, they suggested a solution that "*builds on this option within the Revised Phase 1 Solution"* and "*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.*" They further said, "*It is essential that the Supplier Compensation mechanism is designed so as to avoid any negative interaction with Reliability Option Difference Charges*" and "*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.*" They said a key concern is "*the possibility of PCOMP rising above the Reliability Option Strike Price for any period.*"

The respondents said also that "*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.*"

Two other respondents said they had "*concerns over the application of a compensation payment to Intermittent DSUs as well as Long-Runs*" and that "*this is to do with the ability to financially cover the amount.*", and said "*there should be a separate approach, on the application of 'compensation' payments, for 'Long-Runs' and 'Intermittent' DSUs*". They suggested that "*the 'compensation' payment for 'Long-Runs' be made equal to any energy payments calculated. Currently the associated* [Trading Site Supplier Unit] *provides a similar function, insofar as it removes the payments to the DSU.*" Another said the price "*should be based on a fair representation of the costs that suppliers would incur in the absence of demand reduction*". This respondent also said there should be a separate approach for "*long-runs*".

One respondent said *"the most appropriate structure will change from year to year*" and that there "*will be too many ongoing adjustments required to try to keep the mechanism 'fair' and each adjustment will have an impact on profitability and even solvency for DSUs, particularly short-run DSUs*." It said further that therefore "*it is important that this be an interim solution only.*"

One respondent said it "*needs to see detailed proposals from the RAs on how PCOMP may be calculated prior to opining on which costs would be appropriate to include or not.*" Another respondent said "*The methodology for calculating the Supplier Compensation Price should be flexible in that it should be subject to change in cases unforeseen outcomes are observed rather than explicitly defined in a rule document such as the T&SC where changes can take over a year to be given effect.*" [Another said its view is "*that a further consultation must be held as to decide the formula for calculating these payments.*"

3.6. Supplier Compensation Price and 'Long-Run' DSUs (Question 6)

The Consultation Paper invited respondents to comment on whether the Supplier Compensation Price (PCOMP) would provide the correct incentives for long-run DSUs, other DSUs, and impose reasonable costs on end consumers. Nine respondents commented.

Two respondents said it "*does not believe the Revised Phase 1 Solution, as proposed in the Consultation, would have the correct incentive effect on long-run DSUs.*" It said further that "*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*". Regarding reasonable costs on end consumers, this respondent said *"compliance with EU Law Provisions cannot be limited to only those that are judged to have 'reasonable costs'".* It said further, "*The TSO's impact assessment was carried out during the high prices of 2022, and were expected to fall significantly*", and that "*As such, the cost reduction measures in the Consultation are unnecessary, and have no bearing on the need for compliance with EU Law Provisions.*"

Three respondents said they believed "*a correct calculation of the 'compensation' payment for 'Long-Runs' would have the result of allowing such units to continue to participate in the markets without significant negative impact*". They said also that "*use of the word 'incentive' doesn't really cover this aspect, but we understand that lack of 'Penalties' doesn't sound as useful*", and that "*The monetary amount for covering 'intermittent' DSUs is small in the overall Imperfections and therefore the correct 'Incentive' is to pay such DSUs for energy and not implement 'compensation' payments against them.*"

One respondent said "*It is difficult to accurately quantify until clarification is provided and modelling on DSU expected behaviour and operational changes are defined.*" It said that "*there are risks that the level of the Supplier Compensation Price might change the running behaviour of "long-run" DSUs, with the result that they only run at times when the Imbalance Price is higher than Supplier Compensation Price. This change would impose unreasonable cost on end consumers. Such risks are only fully mitigated by excluding 'long-run' DSUs from the proposals.*" Another respondent said that in its view, "*DSUs are already have adequate incentivises to participate in the market*" but said it agreed with "*the need for different treatment of long- and short-run DSUs to prevent overcompensation and ensure fair participation*".

Another respondent said "*Whilst it looks like it should work adequately, it is hard to anticipate how it will interact with new technologic and market developments. We do note that the previous arrangements ultimately turned out to have unexpected consequences, leading to the current consultation.*" Another respondent said it would require "*more detailed proposals prior to opining on whether PCOMP would have the correct incentive effects*".

3.7. Determining Non-consumed Energy (Question 7)

The Consultation Paper invited comments on whether, in the absence of a system for identifying suppliers of demand reduction customers, non-consumed energy quantities could be determined by voluntary agreement between suppliers and DSUs or by ex post analysis of demand reduction dispatch decisions. Eight respondents commented.

One respondent said it supported "*the use of ex-post analysis to handle supplier corrections for non-consumed energy until an enduring solution is in place that accurately identifies all suppliers benefiting from demand response*." It said, "[W]*hile we acknowledge the SEMC's concern about the potential administrative complexity and time lag associated with ex-post analysis, we believe that the benefits to consumers of a standardised process outweigh these considerations.*" It said further, "*If the SEMC introduces additional sub-metering and baselining requirements for DSUs, applying an ex-post approach would provide better value-for-money to the consumer by making better use of those investments.*"

Two respondents said they believe "*market settlement systems should be used through the use of ex-post analysis of demand reduction dispatch decisions*". Another respondent said "*We suggest that ex-post analysis of demand reduction dispatch decisions, combined with a standardised compensation mechanism, would provide a more reliable and transparent approach.*"

Two respondents said that voluntary agreement between supplier and DSU "*would be a significant reversal of the progress the SEM have made in integrating demand response into the market.*" It said "*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.*" It said ex post analysis would be "*more appropriate assuming it describes Model 2 outlined in the Consultation*".

One respondent said in respect of supplier-DSU agreements "*This may work for large units where there are the resources to oversee the negotiation, however it is difficult to see how smaller units would be in a position to represent themselves sufficiently in negotiations.*"

One respondent said it was "*of the view that further work on a solution where this is addressed through voluntary agreement between the supplier, the DSU and the relevant IDSs is appropriate.*" It said that this was considered in SEM-19-013 and that "*the Phase 2 solution will entail a significant implementation project for whichever entity is tasked with managing adjustments for "non-consumed" energy*".

3.8. Categorising DSUs (Question 8)

The Consultation Paper asked for views on whether it would be possible to categorise DSUs into long-run and intermittent so as to determine whether or not compensation for missing money would be appropriate. Eleven respondents commented.

One respondent said it believed "*there is merit in categorising DSUs based on response duration and operating hours to determine compensation eligibility for DSUs.*" It said "*further analysis is required to understand how operating hours and response duration can be effectively integrated into the compensation framework*" and that it "*would welcome additional consultation on this matter to ensure that any proposed changes accurately reflect the unique characteristics of DSUs within the SEM and promote fair and efficient market outcomes.*" It said also that it "*would also support the introduction of a single de-rating factor for DSUs, irrespective of their MW size, but with adjustments based on their response duration.*"

Two respondents said they accept “*that DSUs could be categorised into ‘Long-Runs’ and ‘Intermittent’ insofar as they operate in a different mode and the commercial Offers made to the market are significantly different.*” They said “*‘Long-Runs’ would normally be bidding in negative monetary values in order to stay dispatched and their running hours duration would be significantly greater than those of ‘intermittent’ units.*”

One respondent said it believed “*it is feasible to create categories for DSUs into ‘long-run’ and ‘intermittent’ DSUs based on criteria such as running hours*”. It said “*‘Long-run’ DSUs typically ... provide consistent demand reduction and do not face the same financial risks as intermittent DSUs because their operational costs are usually covered by savings in supplier charges*” and that “*‘Intermittent’ DSUs ... face greater uncertainty in revenue because they are not always operating, and thus they are more susceptible to the "missing money" problem.*”

One respondent said “*if it were possible to categorise DSUs based on differing underlying characteristics ... this would be worth pursuing. If this could provide consumers with better value than the implementation of PCOMP, it would be particularly worth investigating further*.”

One respondent said it believed “*the workstream underway within the Future Power Markets programme in relation to Dispatchable Demand/Consumption units should be expanded to assess the appropriate categorisation of these type of units. This is in particular appropriate when onsite dispatchable generation is the means by which the demand response is provided.*”

One respondent said “*It is clear from operational behaviour and analysis completed by the TSOs and MO on Commercial Offer Data (COD) and Technical Offer Data (TOD) which DSUs operate as ‘long-run’ DSUs vs “short-run” DSUs*” but that “*it would be more appropriate to have the categorisation done in advance, e.g. at registration stage, rather than retrospective based on analysis of operational behaviour, COD or TOD.*”

One respondent said that rather than a “dichotomy” between long-run and intermittent, “*it might be more appropriate to have a gradiation*”.

One respondent said that it believes that "*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.*" and that "*we see no clear way to define, with any regulatory legitimacy, a basis for differentiation between DSUs.*" This respondent said also that it was "*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.*"

One respondent said *"the persistent use of the term "long run DSU" is concerning, as the SEM Committee appears to be using it to draw distinctions between units that do not exist."* This respondent also said *"The growing narrative that delineates between 'modes of participation' of units in the SEM is worrying, and fundamentally incorrect*" and that "*nor, in any documentation, is it specified that the values submitted under this framework could lead to differential treatment within the market.*"

One respondent questioned whether there is a requirement for it "*to categorise DSUs into long-run and intermittent DSUs, in respect to its role as an MDP*".

3.9. Capacity Payments and Charges (Question 9)

The Consultation Paper invited comments on the analysis of Capacity Payments and Capacity Charges and whether Capacity Charges should be levied on non-consumed energy, e.g. by an adjustment to the supplier compensation price. Nine respondents commented.

One respondent said that "*To the extent that DSUs can make demand response available for dispatch, the System Operators believe that they should be eligible for Capacity Payments on a similar basis to other capacity providers.*" It said it "*would argue that a charging base that takes account of non-consumed energy would be appropriate*" and that "*Care is needed to ensure that the balance of incentives from energy payments and charges is carried through to Difference Payments and Charges and ultimately to Capacity Payments and Charges.*"

One respondent said "*On the face of it, capacity charges should be levied based on consumption of capacity resources at times of stress"* and that "*If capacity is being procured, the person who supplied the capacity should not be paid a second time in* *the form of not having to pay capacity charges*" but that "*our current capacity charge does not work like this; capacity is charged even on days or hours where there is unlikely to be any system stress*" and that "*In this context it seems to make more sense that capacity charges not be levied on consumption that doesn't 'hit' the system"*.

One respondent said it "*agrees that Capacity Charges should be applied to non-consumed energy through adjustments to the supplier compensation price*", and that "*Allowing DSUs to avoid capacity payments could undermine market parity and result in an increased burden on suppliers and ultimately consumers.*". It said also that "*It is important that the RAs and MMU monitor DSU behaviour closely, particularly around bidding practices, to prevent attempts by DSUs to strategically reduce demand to avoid Capacity Charges while still benefiting from capacity payments.*"

Three respondents said they "*do not see a suitable suggestion as to the justification of taking away capacity payments to participants, since they have invested in the provision of services.*" They said further that they "*understand that any reduction in consumption from the grid by a customer shall result in a variety of supplier charges not being paid*" and "*It is the general nature of suppliers to witness growth in demand as well as shrinkage in demand, and the Supplier can reposition their charges/tariffs to compensate.*"

Two respondents said "*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.*"

One respondent said it "[did] *not fully follow the logic of the paper in regard to capacity payments and charges for DSUs and the impact of the proposed phase 1 solution.*"

3.10. Baselining (Question 10)

The Consultation invited views on whether some form of baselining is needed, and whether supplier compensation payment arrangements would affect this. Ten respondents commented.

One respondent said it believed "*a form of baselining is necessary to accurately measure DSU demand reduction i.e., to ensure that compensation reflects genuine demand reduction (rather than mere deviations from typical consumption patterns) and aligns with the true value of demand-side contributions to system stability.*" It said it understood "*that the forthcoming EU DSU Network Code is expected to standardise baselining methodologies across Member States, therefore it is likely baselining will be required in the SEM*" and that "*The SEMC should consider whether additional measures are needed to ensure that the baselining approach accurately captures differences in the value of demand reduction provided by long-run and short-run DSUs.*"

One respondent said "*Some form of baselining is required to move beyond setting the metered quantity (QM) equal to the dispatch quantity (QD) for Settlement.*" It said "*it should be noted that at present the meter polling and aggregation systems do not account for dispatch instructions, and do not perform any baselining calculations. Implementation would require a system change which would not be trivial to effect as, presently, metering and dispatching are entirely separate data streams.*" Regarding how baselining could be implemented, it said further that "*If meter data is used, it may be that the Meter Data Provider is required to carry out a comparison of a "snapshot" of consumption prior to receipt of dispatch instruction*" but "*If SCADA data is used, it is likely this will come from a given participant, i.e. the DSU aggregator's control system, in which case the aggregator will be performing the baselining.*"

One respondent said "*it's crucial the Demand Side Units are performing according to the same standards as other market participants.*" The respondent said that it "*believes* [Grid Code rules] *can be utilised immediately to provide an initial view on the unit's performance*" and that "*where unit does not perform according to these rules TSO should be able to overwrite currently used logic (QD=QM) with a value of demand that unit did provide.*" It said further that monitoring "*could be implemented as an ex-post process with new values being submitted for Initial (D+5) or first scheduled resettlement run (usually M+4)*" and that "*While we would consider this solution being only an interim one, we believe it could be implemented in relatively short time and could be used until the enduring solution with a full operational metering is delivered.*" This respondent also suggested "*there should be a* *comprehensive review of other provisions currently in place under the Grid Code – e.g. Demand Side Unit Best Correlated Profile and Demand Side Unit Energy Profile.*"

One respondent said "*baselining is recognised in the draft NCDR as vitally important to the participation of DSUs in the electricity market. The draft NCDR proposes to create an EU repository for approved baselining methodologies.*" and that it "*broadly agree[s] with the approach set out in the draft NCDR*."

Two respondents said "*this question is misleading, as it suggests there is no current form of baselining in place*", that "*DSU dispatches are currently baselined as per the methodology outlined in the Grid Code*" and that "*it is disingenuous to imply that there is currently no methodology in place*". The respondent said that *"supplier compensation has no bearing on the requirement for refinements of the baselining methodology*" and that "*Baselining is a complex issue and should be discussed bilaterally with industry and consulted upon in its own right.*"

Three respondents said the "*paper discusses baselining as if the response provided by DSUs to a dispatch can not be trusted and this is an approach that [it] can not accept.*" It said "*The ability for each IDS to provide reduction is tested and baselined by the TSOs under Grid Code.*"

One respondent said "*There should be some form of baselining. However, baselining should be viewed more as an intermediate step rather than as a long-term solution.*" It said "*it does not work for the long-term for the simple reason that the baselining period (before the incentive was introduced) is becoming more and more remote.*" and that "*For the most part, incentives based on the baseline should be phased out over time in favour of more 'implicit' measures.*"

3.11. Sub-metering and SCADA (Questions 11 and 12)

The Consultation invited views on the importance of sub-metering, and whether it would be appropriate to use SCADA data to determine DSU quantities. Eleven respondents commented.

One respondent said "*we agree that some form of sub-metering may provide a suitable way to ensure that QD is verifiable, subject to the TSOs' confirmation that* *existing data streams would not provide sufficient verification. In this case, cost-effective sub-metering could level the playing field for all participants.*" It supported the use of SCADA data "a*s long as it is reliable and can be validated*" and suggested "*SCADA data should be cross-referenced with meter data to verify that DSUs are being compensated appropriately, consistently and accurately.*"

One respondent said, "*Metering and sub-metering is important to ensuring that DSUs deliver on their dispatch instructions*" and that "*an evolution of how DSUs are metered is necessary prior to the full implementation of energy payments.*" It said that if the RAs propose using SCADA, there should be a separate consultation.

Another respondent said it believed, "*there is an urgent need to create a link between DSU performance and its market settlement*", and that "*TSOs are already receiving the SCADA data from DSU operators therefore naturally this data should be used in a short term as a replacement of operational metering*." It said further, "*Depending on a result of the Demand Response Networks Code consultation the move towards sub-metering may be required in the future however that should not stall/delay the process of creating more equitable landscape for performance monitoring and settlement renumeration within I-SEM*."

Two respondents said "*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.*" They said, "*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.*" They said agreed with the use of SCADA data and said, "*SCADA data should be used in place of the majority of EDIL declarations.*"

Three respondents said "*Sub-metering could provide a more accurate measure of the demand reduction provided by DSUs. However, the costs and benefits of implementing such a system need to be carefully considered.*" Two said, "*DSU operators are currently required to provide the TSOs with SCADA values that the DSU operator collects from all of its IDSs. Whilst these are not metering to the level* *required by Grid Code, they are an indication of the level of demand response based on the time of dispatch.*" The third said "*DSUs are providing DS3 System Services, and the accuracy of the metering required is to a higher standard than that required by Grid Code.*"

One respondent said "*In terms of equitable treatment of different technologies, DSUs are a notable exception in that all other technologies are required to pay the cost of revenue metering installations. Sub-metering may be the most accurate and most transparent data source that could be used for QM; however, it could also prove the most problematic in terms of the cost, timeline and even practicality of (retrospective) implementation.*" It said it would be, "*the responsibility of ESBN and NIEN to install main and check revenue class metering at these sites and to be Meter Data Provider (MDP) for the majority of these IDS's*" and, "*Each MDP would need to have the system ability to aggregate multiple IDS sites into one DSU for meter data feeds to the SEM as per settlement timelines.*" It said also, "*Any sub-metering solution would require that the Meter Data Provider maintain connections to a potentially large number of meters. This would be burdensome in terms of upkeep. It is perhaps acceptable, then, to use participant SCADA while noting that the burden falls upon the Meter Data Provider both to understand the measurements, calculations and controller logic behind the participant SCADA input, and to ensure its accuracy via testing and monitoring.*"

One respondent said, "*although there may be some benefits to using sub-metering, it is envisaged that the introduction of a sub-metering arrangement would be quite complex, costly and challenging to implement*." It said, "*It is probable that ESB Networks will receive requests to accommodate non-standardised meter configurations for the diverse range of customers participating in demand response services, resulting in increased complexity and costs*." It said further that SCADA is, "*widely accepted as not providing revenue grade data*" but that, "*SCADA may form part of a solution, in particular if there are interim measures required.*"

One respondent said "*Sub-metering is extremely important. It appears to be all but inevitable to implement the requirements of the recast electricity markets directive*". It said it agreed with using SCADA in principle, but "*in practice there are some substantial problems*", and that, "*To be able to use this information usefully, it needs* *to be correlated to the site and the supplier unit registered as a supplier for the site. This may present a difficulty in how the sites are configured.*" It said, "*the simplest way to resolve this might well be new metering and a new system for dealing with aggregators and secondary suppliers. This 'behind the meter' metering is quite different in nature from the current DSO and TSO metering and new arrangements are probably required for it.*"

One respondent said, "*sub metering may be a more accurate way to measure demand reduction than baselining or Scada, however a comprehensive assessment would be required to fully understand the feasibility and detailed implications of this.*" It said, "*This feasibility assessment should include the detailed requirements, timeframes and costs for all aspects of installation, maintenance and replacement of sub-metering arrangements, including meter asset ownership and charging arrangements.*"

3.12. Aggregated Generator Units (Question 13)

The SEM Committee invited views on whether on-site generation could be accommodated in SEM through the arrangements for Aggregated Generator Units. Eleven respondents commented.

One respondent said it agreed that, "*DSUs can, in principle, be facilitated through an Aggregated Generating Unit (AGU) arrangement*." It noted that "*in practice this arrangement may be undesirable to DSU operators given the additional burden of compliance requirements associated with on-site generation, such as environmental regulations or licensing for generation, which a DSU might want to avoid.*" Another said, "*it does appear that certain on-site generation is more suited to forming part of an Aggregated Generator Unit. This could particularly apply to long-run DSUs, which as stated in the consultation do not provide genuine demand response at times of high prices as would high-cost DSUs.*"

One respondent said, "*There is no end of potential configurations. A supplier unit could also be used for this aggregation under the de minimis arrangements. Perhaps there are too many potential configurations, and everything needs to be simplified.*" "*This question is no doubt a reflection of the great change coming to the market as the practical differentiation between those providing capacity (traditionally*

GUs and DSUs) and those consuming capacity (traditionally SUs) begin to blend together."

Two respondents said "*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.*" They said, "*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.*" They said, "*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.*"

Two respondents said, "*AGUs deal with generators and thus they aren't appropriate for all DSU scenarios.*" "*Currently AGUs require an equivalent value of maximum Export Capacity (MEC) which brings along additional costs, technical requirements and regulatory paperwork.*" Another respondent said, "*DSUs do not require an MEC*" and that "*An MEC can take years to obtain, if even possible, making this an unfeasible proposal.*"

One respondent said, "*The Aggregated Generator Unit (AGU) model is enabled in Northern Ireland where generators less than 10 MW can be included in the market via an aggregator through licencing and grid code arrangements. However there may be gaps in the framework in Ireland which may impede use of such a model there – changes to address any such gaps should be considered.*" It said further that, "*The Dispatchable Consumption model, currently under development, may also be a more appropriate model for these types of assets.*"

One respondent said "*there is currently no mechanism in the ROI retail market to facilitate Aggregated Generator Units. ESB Networks would be supportive of any process CRU or SEMC initiated to progress the introduction of Aggregated Generator Units into market design in ROI.*"

One respondent said, "*There is currently no restriction on the maximum length of demand response unit can provide. This creates a situation where units able to provide 0.5h of demand response and nearly continuous demand response are* *treated under the same set of rules. The utilisation of other, more appropriate, arrangements already existing under TSC should be encouraged as a viable option for long-run DSUs using the on-site generation.*" It said regarding units that use on-site generation, "*there may be an opportunity to create similar arrangements that are currently in place for Autoproducer units.*"

3.13. Other Issues (Question 14)

The Consultation invited views on any other issues relating to the treatment of DSUs in the SEM. Nine respondents commented.

One respondent said it had, "*previously commented on the scale of changes being proposed as part of the enduring solution for energy payments for DSUs.*" It said, "*Extending the enduring solution into a Phase 1 and Phase 2 solution adds further complexity to any implementation which is further complicated with extending Phase 2 with two potential models included in the latest consultation paper*." "*With respect to the Phase 1 proposal, as noted earlier, EirGrid and SONI believe that a detailed cost benefit analysis should be undertaken by the Regulatory Authorities as part of the SEMC decision on whether to adopt the revised Phase 1 approach.*" It said also that this analysis should, "*consider whether the original Phase 1 approach proposed in SEM-22-036 could be applied to "short-run" DSUs only*" which it said "*may be less costly than the required implementation of the revised Phase 1 solution.*"

The respondent said also that, "*The proposal for Model 3 as set out in the consultation may negate the need for some of these data exchanges by not requiring the end consumer to be billed for non-consumed energy; however, the proposal to introduce additional cash flows between the DSUs and relevant Supplier Units under the T&SC will result in significant complexity being added to wholesale market imbalance settlement to resolve what is essentially a retail market issue.*"

One respondent said it "*would like to ask RAs to consider implementing the Phase 1 changes that can use the existing environment and available data (performance monitoring, metering, and bidding) as quickly as possible*" and that "*changes that do require system releases should not create a roadblock to implementing other improvements in DSU treatment in the interest of equity amongst market participants and value for money for consumers.*" The respondent said it was "*cognisant of the* *focus of this consultation paper*" but believes it's necessary "*to broaden the discussion regarding the enduring arrangements for Demand Response participation and the need for creating level playing field between all market participants.*"

One respondent commented that "*a flexibility market is under development with initiatives such as Pilot 1 and Beat the Peak.*" It said, "*These initiatives use a baselining methodology and as such, further engagement will be required on the proposed methodology*" but that "*the flexibility market would support the recognised approach identified in the consultation paper.*"

One respondent cited a number of issues: it sought clarity on implementation timelines; it sought publication of DSU performance analysis; it stated a need for Complex COD for DSUs to be reflective of real costs; and it expressed concern that SEM arrangements align with the ACER Consultation on the draft DSU Network Code. It said that the decision on this consultation should balance immediate market needs with being prepared to align with the outcome of ACER's consultation, including how EU-standard baselining methodology will be integrated into the Phase 2 solution.

Two respondents said that "*the paper ... is placing many 'incentives' (penalties) that ultimately undermine any support that the RAs may want to express going forward.*" Another said, "*The implementation of the Revised Phase 1 solution suggests that DSUs will both incur a penalty as well as an incentive, which incidentally undermines the support which was originally understood.*"

Two respondents said, "*The Consultation fails to mention the historic payment of energy payments to DSUs, which have been entitled to such payments since 1 January 2020.*" and "*we ask that the SEM Committee begin to engage with the industry as to how these historic payments will be made*."

3.14. Negative Demand Response (Question 15)

The Consultation invited views about negative demand response. In particular, it asked whether supplier compensation would work with negative demand response and whether there is the potential for perverse outcomes and discrimination between customers. Eight respondents commented.

Two respondents said, “*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*”. They said, “*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*.” Lastly, it said, “*The supplier compensation should have the capability of flowing from the supplier to the service provider in the event of negative demand response.*” and that “*there are no perverse outcomes from market participants performing actions as dictated by the market rules in place for all units.*”

Two respondents said, “*If there is a requirement for the TSOs to increase demand (consumption) then that capability would require similar investment to that of demand reduction. Such investment needs financial recovery via the Capacity market and ultimately the cost of responding to a dispatch would also require energy payment.”* Another respondent noted that DCUs had recently been proposed by the TSOs, and negative demand response had been discussed in the context of the DASSA arrangements.

One respondent said it believed, “*this proposal lacks justification and information regarding its potential risks, and therefore warrants separate consultation (which could be published alongside the proposed MMU guidance measures).*” It said, "*We are concerned that negative demand response could introduce perverse incentives and market distortions if not managed properly*” and asked “*the SEMC and the MMU to carefully consider the potential risks of negative demand response and to evaluate whether the proposed monitoring measures are sufficient to prevent DSUs engaging in speculative behavior to arbitrage price differences between markets without providing real system value.*”

One respondent said, “*If this approach to dispatching “long-run” DSUs is to be considered for turning up demand above baseline levels, we believe that this would cause the perverse outcome of consistent imbalances in the market and on the system.*” As regards supplier compensation, it said, “*this would appear to work as intended but further modelling is recommended*” It said also, “*We note that there is* *an action as part of the CRU's National Energy Demand Strategy decision paper on EirGrid to develop the "Dispatchable Consumption" model, which is considering this kind of negative demand response"* and that this is currently being progressed under EirGrid and SONI's Strategic Markets Programme.

One respondent said it "*would welcome further consideration of the potential benefits of dispatchable consumption, and its potential to add flexibility to the system and reduce the dispatch down of renewables.*" Another said, "*the current view is Dispatchable Consumption Units (DCUs) will participate in the market as a new technology type but with same obligations as other market participants without any special provisions that are currently allowed to DSUs.*"

3.15. Shutdown Costs (Question 16)

The Consultation invited views on how shutdown costs for IDSs should be reflected in COD for DSUs. Eight respondents commented.

Two respondents said, "*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.*" They said further that, "*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.*"

Three respondents said "*DSUs currently comply with the BCOP and the proposals in the paper are not in line with BCOP. The suggestion that Shutdown costs should reflect the actual reduction is unworkable.*" "*As such all costs must reflect the best-case scenario of full dispatch by the TSOs as part of balancing the System, and Offers into the markets reflect that.*"

One respondent said it, "*supports the principle that shutdown costs for Individual Demand Sites (IDSs) within a DSU should be proportional to the actual demand reduction each site provides. It is important that these costs accurately reflect the* *contribution of each IDS, rather than allowing DSUs to aggregate shutdown costs across all IDSs regardless of each one's participation in the demand reduction.*"

One respondent said in respect of shutdown costs and decremental prices, "*Any bid submissions need to ensure they are in line with Bidding Code of Practise. If necessary, the guidance suggested in the consultation should be issued to ensure there is a clear baseline that can be used to assess DSUs bidding behaviour is appropriate.*"

One respondent said, "*There is a lack of transparency for IDSs within the market as we do not see which IDS is activated within the DSU when dispatched, meaning it is difficult to account for any cost incurred when shutting a DSU down. There are also issues relating to the methodology used to calculate the DSU cost when multiple IDSs are grouped together, which can lead to an over recovery of true cost by averaging the highest cost IDS across other lower cost IDSs. We would welcome greater accuracy and transparency with clearer guidance on how this should be calculated*."

3.16. Decremental Prices (Question 17)

The Consultation invited views on how decremental prices to reduce demand reduction should be calculated.

One respondent said it "*supports a framework where decremental bid prices for demand reduction are directly tied to real costs, with negative bids allowed in specific, justified cases, with sufficient monitoring to avoid market distortion.*"

Two respondents said, *"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."*

One respondent said it could, "*see* a *clear differences in the cost of demand reduction depending on the DSU. Costs for DSUs based on process reduction are* *different to the cost of a "long-run" DSU who may reduce their output using on-site generation.*"

Three respondents said, *"This question may be answered differently by 'Long-Runs' and 'Intermittent' DSUs, and the market encourages lower Offer prices."* Two said further that "*The decremental bid price for reducing demand reduction should be calculated by considering a range of factors, including the operational costs of increasing demand, opportunity costs associated with foregoing further demand reductions, market price signals, restart costs, potential revenue gains, and system conditions.*"

One respondent said, "*it's crucial DSUs are complying with financial regulations rules – e.g. REMIT.*"

3.17. Grid Code Availability Declarations (Questions 18 and 19)

The Consultation asked whether respondents agreed that the Grid Code requires DSUs to declare an availability of 4MW or above, and whether it requires DSUs to round down their declared availability to the nearest MW.

Two respondents cited the Grid Code as stating, "*an Individual Demand Site or Aggregated Demand Site with a Demand Side Unit MW Capacity of at least 4 MW*" and said, "*This does not include any requirement for DSUs to declare an availability of 4 MW or above on a regular basis.*" It said also that it "*does not accept this interpretation of DSUs' binding obligations regarding availability declarations under the Grid Code.*" It said further that "*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.*" Another respondent agreed that there's no requirement under either the SONI or EirGrid Grid Code for DSUs to declare an availability of 4 MW or above. Regarding rounding, it said that "*the DSU must declare their availability as a whole number which the DSU can deliver when requested to do so. As a result, this may require them to round down their availability to the nearest whole MW*."

Two respondents said that "*The assumption in the paper that there is a requirement to declare an availability of 4MW or more is in error*" and, moreover, that the value should be reduced to 1MW and that, "*To do otherwise means that the TSOs are* *missing out of valuable demand reduction.*" On rounding the respondent said, "*It has been discussed with the TSOs many times that the EDIL software is no longer suitable for today's markets and System operations, however the TSOs remain reluctant to address their issues*" and that, "*The paper correctly identifies the requirement for the TSOs to allow bids at 0.1MW granularity, but that requires a system to handle availability declarations.*"

One respondent said "*If DSUs are required to round down their declared availability to the nearest whole number, they may lose out on compensation for the fractional MW of demand reduction they can provide*", that "*EDIL investment is required*" and that, "*the proposed NCDR requires the TSOs to develop a roadmap to allow 0.1MW granularity*".

One respondent said it agreed "*that DSUs should regularly declare an availability of 4 MW or more, as required by the Grid Code*." It said, "*If DSUs are found to be consistently declaring low availability following the implementation of any of the measures outlined in this consultation, then the SEMC should consider introducing additional requirements". It said it agreed also that "DSUs should be required to round down their declared availability to the nearest MW in line with Grid Code requirements to submit availability that is realistic and achievable*." Another respondent said it agreed with the analysis in the consultation in respect of both the 4MW minimum and rounding.

3.18. EU Legislation

One respondent provided extensive comments concerning EU provisions and the consultation process.

The respondent said, "*The SEM Committee's intentions in this Consultation are to form an appropriate compensation mechanism to reduce the cost of implementing energy payments for DSUs. Unfortunately, in its efforts to rationalise the solutions proposed therein ... the SEMC misrepresents critical information on the operation, performance measurement, and settlement of DSUs.*" It requested that the SEM Committee issue a new consultation making amendments to what it argued are inaccurate statements. In particular, the respondent cited three statements in the Consultation:

(1) It said, "*The Consultation frequently distinguishes between DSUs based on their usual market participation characteristics. The growing narrative that attempts to technically distinguish between "long run" and "short run" DSUs in the SEM is concerning and fundamentally incorrect.*"

(2) It said, "*The Consultation Paper twice states that DSUs are exempt from balance responsibility, providing the following rationale in Section 4.3 under the heading "Metering": '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.'*" The respondent said, "*This statement is demonstrably incorrect and misleading.*"

(3) It said, "*In the Consultation Paper, the SEM Committee states that the proportion of costs associated with the measure approved in Mod_02_23 was not apparent during the decision-making process. However, as stated in the Final Recommendation Report for Mod_02_23, 'The TSO Member advised that following a review of data for the year 2022, it was estimated that, all things remaining equal, there would be an additional imperfection cost of between €60 - €65 million. This amount would not be proportionately distributed with only a handful of the 49 units registered in the observed period receiving the vast majority of it due to their specific market conditions'.*" It said further that, "*These 'market conditions' or bidding behaviours have 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*."

With regard to EU provisions, the respondent said, "*DSU energy payments are mandated by the EU Law Provisions, all of which were in force by 1 January 2020.*" and that "*Pursuant to the EU Law Provisions, there is a clear obligation on the SEM Committee to ensure that DSUs are capable of participating in the market alongside generators in an equal manner.*" It said "*In this Consultation, as well as in other publications, the SEM Committee admits to having delayed this modification on the* *basis of an 'impact assessment' of the cost implications to the system of granting DSU energy payments.*" and that "*It is clear from the above statements that the SEM Committee is attempting to implement a measure such that some DSUs would not be granted energy payments in any meaningful way due to the costs associated with doing so, despite there being no provision in the EU Law Provisions for delaying or avoiding compliance on the basis of cost.*"

The respondent said "*the SEM Committee proposes a mechanism designed to mitigate the cost of the obligations required by the EU Law Provisions. This mechanism ultimately arises pursuant to Article 17(4) of the Directive*". It said, "*This optional compensation is separate from the mandatory obligations to ensure equal market treatment for DSUs under the EU Law Provisions.*" and that, "*Unlike the binding obligations arising under the EU Law Provisions, measures pursuant to Article 17(4) can be implemented at the discretion of the Member State. Therefore, the ongoing delay in meeting the obligations under the EU Law Provisions as a result of the intention to implement a measure under Article 17(4) is misconceived and unlawful.*" It said, "*This is especially striking because a known, compliant, and approved measure exists in the form of Mod_02_23*."

The respondent also cited the State Aid decision concerning the Capacity Remuneration Mechanism[13]. It said, "*It was therein noted that the exemption of DSUs from payback obligations in certain circumstances was 'acceptable as a temporary measure' given that DSUs did not receive energy payments. However, the Commission expressly stated that 'the situation that DSUs cannot access energy payments needs to be remedied in the medium term' and 'once the I-SEM reforms are implemented'. In response to this, it was stated that 'the authorities have committed to end the exemption from payback obligations for DSUs as of the delivery period starting in October 2020', and this commitment was welcomed by the Commission.*"

[13] "State aid No. SA.44464 (2017/N) – Ireland – Irish Capacity Mechanism", European Commission, 24 November 2017.

The respondent requested that, "*1. The Consultation is revoked; 2. Mod_02_23 is implemented in full and without delay;* [and] *3. A new Consultation is issued, aimed at identifying the best solution for a measure under Article 17(4).*"

3.19. Implementation

Two respondents provided extensive comments on implementation.

One respondent noted that the various models present different implementation challenges. It observed that Model 2 involved "*identifying the relevant supplier for each DSU*" and that "*SEMO and the TSOs have no visibility of the relationships between an IDS and its Supplier Unit, while the DSOs do not have visibility of the make-up of each DSU.*" It suggested that this model "*could lead to significant changes to retail market rules, retail market systems, supplier codes of conduct, supplier licences and even legislation. As such, this is not a simple modification and would take considerable time to implement.*" It commented that Model 3 was similar to Model 2 but that there was, "*significant complexity to the current balancing market settlement design*".

The respondent commented on the Revised Phase 1 Solution. It said that, "*Additional design and implementation work would be required to develop and subsequently implement a modification for this solution*" and that "*It should be considered that there are many competing priorities over the coming releases, e.g., Tranche 1 and 2 of the Scheduling & Dispatch solutions, system updates required for Celtic integration, etc.*" It said further that "*implementation of the revised Phase 1 Solution is not trivial*" and that "[*C]areful thought would need to be given to the algebra to consider the outcome on DSUs and the impact on the Imperfections fund in different scenarios.*".

The second respondent said that, *"The TSO/DSO Operating Model High Level Design (HLD) has been agreed between the system operators. This outlines the future plans for exchange of data between the system operators as well as expected roles for issuing dispatch and activation signal instructcions to different types of resources."* It said, "*The development of the detailed design of this model is now underway where this arrangement will be considered further*" and that, "*The outcome* *and implementation of this detailed design may have some overlap with the considerations for the SEM proposals in this consultation.*"

The first respondent provided updated analysis which it said shows that payments to DSUs over the period September 2023 to August 2024 totalled "*approximately €25.25M with €23.75M or 94.03% going to "long-run" DSUs and €1.5M or 5.97% going to "short-run" DSUs.*"

4. Discussion

4.1. DSU Cashflow Models (Question 1)

The SEM Committee notes the comments received on the DSU cashflow models.

The SEM Committee notes the comment that the models are a simplification and that suppliers are likely to purchase power in the ex ante markets whereas DSUs are likely to be called through the balancing market. The SEM Committee recognises that the Supplier Compensation Price would need to be determined with some care, so as to reflect the costs incurred by suppliers that are reflected in their charges to customers (see Section 4.5); on the other hand energy payments to DSUs will, as with generators, be either at the Imbalance Price or at the ex ante price in the event that the DSU aggregator sells the demand reduction in the ex ante market.

The SEM Committee notes the comments regarding Model 1 on the need for change, and that Models 2 and 3 are the only models that are compliant with the EU provisions. The SEM Committee notes also the objections to the Revised Phase 1 Solution but does not agree. The SEM Committee's view is, for the reasons set out in the Consultation Paper, that the compensation is necessary in order that demand response is appropriately incentivised, is efficiently dispatched, and participates on an equal footing in the market, as required by EU Regulation 2019/943. Nor does the SEM Committee agree that the compensation is inappropriate because it is "indirect". It would be contradictory to interpret the legislation as meaning that any such payments need to be made under a direct bilateral arrangement, as a key objective is to avoid the need for bilateral agreements between DSU aggregators and suppliers. Instead cashflows between market participants generally take place via the market operator, and it is not clear that there is any difference between cashflows that are regarded as being conceptually 'through the imperfections pot' and other balancing market cashflows. Nor is there anything in the Revised Phase 1 Solution that would prevent the supplier compensation payment from being two-way: for positive demand reductions and a positive Supplier Compensation Price then the cashflow will be from the DSU aggregator but for demand turn-up (or in the very unlikely event of a negative Supplier Compensation Price) the cashflow would flow to the DSU aggregator. The SEM Committee welcomes the proposals to resolve many of the issues. Given these relate mainly to the setting of PCOMP, these are discussed in Section 4.5.

The SEM Committee notes and agrees with the comment that the saving to the supplier in Model 1 may not cover the costs of providing the service, i.e. the demand reduction. The SEM Committee notes also the comment that in Models 2 and 3 identifying the demand reduction is difficult and costly. However, the SEM Committee does not agree with the comment that Model 2 is not acceptable as it burdens the customer and that in Model 3 paying compensation to the supplier is not justifiable. If energy payments are made to the DSU aggregator and 'perimeter correction' is applied, requiring the supplier to purchase the non-consumed energy, then the customer is unlikely to want to enter into any arrangement with the DSU aggregator unless the DSU aggregator compensates the customer for the non-consumed energy for which it is likely to be billed by the supplier[14]. The rationale for Model 3 is that, instead of the DSU aggregator compensating the customer for the cost of the non-consumed energy, the compensation is made to the supplier, avoiding the need for suppliers to bill customers for energy the customers haven't consumed. Nor does the SEM Committee agree that the DSU aggregators cannot afford this compensation. As discussed further in Appendix C, the cost of providing the demand reduction, e.g. with on-site generation, is covered by the energy payments to the DSU aggregator provided the DSU aggregator bids the short-run marginal cost of making the demand reduction, while the compensation made to the supplier reflects the additional compensation the DSU aggregator would otherwise have to make to the customer if the customer has to pay for the non-consumed energy.

The SEM Committee notes the comments saying that customers do not share savings with the DSU aggregator and that it would not be workable, and that instead DSU aggregators share revenues with customers. As discussed in Appendix C, the SEM Committee recognises that cashflows are likely to be from the DSU aggregator to the customer, rather than other way round, on the assumption that it is the customer that in the first instance bears the cost of making the demand reduction (as

[14] Nor will the supplier want to supply the customer unless it can bill the customer for the non-consumed energy the supplier is required to purchase from the wholesale market.

may typically be the case). However, the SEM Committee considers that, in Model 3 and the Revised Phase 1 Solution, the customer can still be regarded as sharing any savings in the costs of purchasing from the supplier, in that it will be prepared to agree more favourable terms with the DSU aggregator than if it had to pay for non-consumed energy, as in Model 2.

The SEM Committee agrees with the comments that the Revised Phase 1 Solution addresses the double-counting issue that otherwise allows both DSUs and suppliers to benefit from the same demand reduction. The SEM Committee acknowledges the comment that there will be a cost to suppliers that do not have demand reduction customers. However, the SEM Committee considers that, in the absence of a system for perimeter correction, the cost to these suppliers will be less than with some other suggested solutions, while the cost of implementing a system for perimeter correction could fall on these suppliers, rather than only on the suppliers with demand reduction customers or on DSU aggregators.

The SEM Committee notes the comment from a respondent that said it did not have a third-party supplier and hence did not contribute to the missing money problem. However, in the SEM Committee's view, it is important to ensure both that there is no missing money for any DSU and that there is no double counting whereby the supplier and DSU benefit from the same reduction, in each case regardless of the identity of the supplier and DSU.

The SEM Committee notes the comment that the implications for networks and the retail market may warrant further engagement and expects that such engagement will occur if the proposal is progressed.

4.2. 'Long-Run' DSUs (Question 2)

The SEM Committee notes the comments received on analysis and treatment of 'long-run' DSUs.

The SEM Committee notes the comment that there is a potential issue with long-run DSUs without PCOMP, and it agrees that, without supplier compensation, consumers would face additional costs for little or no benefit. The SEM Committee notes also the comment that the terms "long-run" and "short-run" are analogous to "baseload" and "peaking" as commonly applied to generators, and that, given the supplier compensation mechanism, there is no need to distinguish between DSUs with "*different market characteristics*". The SEM Committee's view is that it is desirable, where possible, to have a set of rules apply to units – generator, DSU, or any other unit – regardless of their characteristics, rather than defining different rules for units with different characteristics. It acknowledges and agrees with the comment that a number of points need to be considered in relation to the level of the supplier compensation price, and these are discussed in Section 4.5. The SEM Committee notes the comment that the general treatment appears reasonable but that how it works in practice and accounts for "*non-energy consequences*" needs to be considered. In its view, such non-energy consequences also relate to the determination of supplier compensation price.

The SEM Committee notes the comments that supported distinguishing between long-run and short-run DSUs, and that tailored compensation is required to ensure DSU payments are proportionate to the actual system value provided. It notes the comments that the analysis "*pushes to make a distinction*". However, in this instance, the aim of the SEM Committee is *not* to have to make such a distinction by having a single mechanism. It agrees with the comment that it is important that any compensation mechanism does not inadvertently penalise long-run DSUs but considers it important also that they are not over-rewarded resulting in inappropriate incentives that put them on an unequal footing with other market participants, and resulting in inefficient outcomes and unjustified costs to all customers. Here, it is important to emphasise that the SEM Committees does not mean by "unjustified costs to all customers" some arbitrary notion of what constitutes a justified or reasonable cost but means that DSUs and their customers should not both be rewarded for the same demand reduction, such that all end customers pay for the same demand reduction twice. The SEM Committee recognises that achieving equitable outcomes for DSUs with the mechanism discussed in the Revised Phase 1 Solution depends on an appropriate supplier compensation price.

The SEM Committee notes the comment that "*persistent use*" of the term long-run DSUs is concerning and is "*fundamentally incorrect*". The SEM Committee does not agree and considers that, while identical rules are desirable, it is possible that in certain circumstances distinguishing between units based on their economic characteristics could be the most effective way to achieve equitable treatment, and it was proper for the Consultation Paper to seek views on that.

4.3. Missing Money and Supplier Compensation (Question 3)

The SEM Committee notes the comments on 'missing money' and supplier compensation.

The SEM Committee notes and welcomes support for a "*refined, transparent and well-monitored compensation mechanism*" and the acknowledgement that this would address missing money and double-counting issues. It notes also the comment that detail of how PCOMP would be calculated is required.

The SEM Committee notes the comment that supplier compensation does not solve the missing money problem and that this is solved by providing energy payments. The SEM Committee recognises that energy payments are required under the Clean Energy Package and considers that they are desirable to avoid the missing money problem in Model 1. The intention of the question was to garner views as to whether energy payments and supplier compensation *together* would address the missing money problem.

The SEM Committee notes also the comment that supplier compensation reduces the net cost of DSU energy payments but does not address the missing money problem and does not resolve the imbalance costs or leave suppliers balance responsible. As just mentioned above, the SEM Committee recognises that the missing money problem is solved by energy payments but, as discussed in Section 4.1 and Appendix C, the purpose of supplier compensation is, when combined with the perimeter correction in Model 3, to avoid double counting of demand reduction by requiring the supplier to buy the non-consumed energy that the DSU aggregator sells back to the system as demand reduction, and to avoid the supplier having to bill the customer for non-consumed energy and the customer having to recover the costs from the DSU aggregator.

For the reasons above, the SEM Committee does not accept the comment that supplier compensation is not a viable approach or the implication it does not create a level playing field for DSUs with other generators. DSUs are in the same financial position under the Revised Phase 1 Solution as under Model 3.

The SEM Committee notes also the comment that it does not reflect the advantage to other suppliers due to the balancing price being lower compared to a counterfactual where a more expensive unit sets the price. The SEM Committee notes that in EU Directive 2019/944 and the proposed NCDR such additional compensation is discretionary. Moreover, it is not clear how this principle is intended to work given every DSU (and indeed each generator) could each argue that it brings down the cost to all suppliers (but also reduces the revenues of other generators), while every supplier could claim to benefit the revenues of every generator (but increase the costs of other suppliers). The SEM Committee also rejects the notion that supplier compensation is an effort to reduce the cost to the suppliers and move the benefit from the customer via the DSU back to the supplier. As has been explained, the purpose of supplier compensation is to facilitate energy payments to DSUs without double counting demand reduction both in energy payments to DSUs and in savings in the cost of purchasing through a supplier.

The SEM Committee notes the comment that all energy should be allocated to a unit where it is generated and a unit where it is consumed and agrees that this would be the ideal situation. However, in the absence of the necessary infrastructure for perimeter correction, the SEM Committee considers that the models discussed, and the Revised Phase 1 Solution in particular, ensure that this principle is applied exactly for DSU aggregators, and with only minor additional cashflows between suppliers, and that there is no double counting (or omission) of energy generated or consumed.

The SEM Committee notes the comments that any rule change should accommodate DSUs that procure power to their own use and that where a site 'has no contract' it does not contribute to the missing money problem. The SEM Committee's view is that to think of a DSU "*contribut*[ing] *to the missing money problem*" is to mis-characterise the issue. Rather, as has been discussed it is the DSU that may suffer a missing money problem, which is what the SEM Committee is seeking to address. Also, in none of the discussion of the issues and potential solutions has the identity or affiliations of any of the various elements, i.e. the supplier or DSU or customer, been of any relevance. Thus, the SEM Committee does not consider that different rules are needed in the absence of a third-party supplier.

Lastly, the SEM Committee notes the comment that the data requirements of any solution need to be understood. The SEM Committee does not anticipate any particular issues with the Revised Phase 1 Solution arising in this respect – albeit recognising that any solution involving a system for perimeter correction could be complex – and expects that such details would be addressed in the development and implementation of any TSC (or other) modification.

4.4. Supplier Compensation via the Imperfections Fund (Question 4)

The SEM Committee notes and agrees with the comments that paying supplier compensation into the Imperfections fund would be appropriate in the absence of a solution to identify suppliers of demand reduction customers, and agrees that this would address the double counting of demand reduction. The SEM Committee notes the comment that it should confirm the double counting issue has been resolved before moving to Phase 2. However, Phase 2, with perimeter correction, is another method for avoiding double counting, and hence the SEM Committee does not consider that confirmation that the double-counting issue is resolved under Phase 1 need be a pre-requisite of moving to Phase 2. The SEM Committee notes also the comments: that proposals do not provide for smoothing costs over time; regarding dependence on the Supplier Compensation Price; and regarding the importance of baselining and detailed metering. While smoothing compensation over time is not explicitly addressed, the SEM Committee notes that, under the Revised Phase 1 solution, the net cost of energy payments and supplier compensation would be recovered through the Imperfections Charge, and thus this net cost is smoothed over the Tariff Year. The SEM Committee acknowledges the importance of the Supplier Compensation Price but does not agree that this price is arbitrary, and the determination of this price is discussed in Section 4.5 and Appendix D. The SEM Committee considers that baselining and metering are separate issues to supplier compensation and these are discussed in Sections 4.10 and 4.11.

The SEM Committee notes the comments that DSUs will not have the financial ability to cover the compensation payment but does not agree. It may be that DSUs have to amend their offer prices, but these offer prices should reflect the cost of making the demand reduction and not some lower or higher value as a result of deducting or adding PCOMP. Otherwise, demand reduction may be dispatched even when the cost of making the demand reduction is greater than market price. Appendix C explains further. The SEM Committee acknowledges that the DSU aggregator may have to "*obtain a value from the IDS*" but considers that, just as a generator must pay for the fuel (and other) costs of generation, it is appropriate that a DSU aggregator receiving energy payments should cover the cost of making the demand reduction, and that the cost should not be also offset by the saving in costs of purchasing from the supplier. While the SEM Committee is keen to enable demand reduction to compete on an equal footing with generation, this does not mean that demand reduction should be double counted, and such double counting would go beyond addressing the 'missing money' problem.

Similarly, the SEM Committee notes the comment that the absence of supplier compensation would not advantage DSUs and that energy payments "*simply put DSUs on a par with generators, while supplier compensation reduces the cost of the measure for all end consumers*". However, the SEM Committee does not agree with this comment. The SEM Committee considers it reasonable to expect that the arrangements between DSU aggregator and customer reflect the customer's cost of making a demand reduction, whether the cost of running on-site generation or the loss to the customer resulting from the demand reduction, for example due to lost production. However, it does not consider it reasonable that these arrangements should ignore the saving in the costs of purchasing from the supplier. As discussed in Section 4.1 above and in Appendix C, with perimeter correction this saving does not arise, as the supplier is required to purchase the non-consumed energy, and without perimeter correction it is unreasonable not to take this saving into account. The SEM Committee recognises that the supplier compensation payment will reduce the costs for all end consumers but the reduction arises because otherwise the demand reduction is double counted, once through the energy payments to the DSU aggregator and a second time through the reduction in the costs of purchasing through the supplier. While the commercial terms between the DSU aggregator and the customer are private[15], it is reasonable that the revenues paid to the customer

[15]Although private, there is a requirement these agreements are reported under REMIT. See Section 4.15.

should reflect the cost to the customer of making the demand reduction, *net* of the saving in purchase costs.

For this same reason, the SEM Committee also disagrees with the comment that DSUs will not have the financial ability to cover the compensation payment. It may be that the DSUs have to amend their offer prices, but these offer prices should reflect the cost of making the demand reduction and not some lower or higher value determined by deducting or adding the saving in the cost of purchasing from the supplier or the Supplier Compensation Price. Otherwise, demand reduction may be dispatched even when the cost of making the demand reduction is greater than market price. Section 4.1 and Appendix C explain further. While the SEM Committee is keen to enable demand reduction to compete on an equal footing with generation, this does not mean that demand reduction should be double counted. Such double counting goes beyond addressing the missing money problem.

Lastly, the SEM Committee notes the comment that "*indirect nature*" of the Imperfections Charge fund implies that supplier compensation should not be made unless it is paid to the suppliers specifically affected by each particular DSUs demand reduction. In the SEM Committee's view, the respondent's assertion that the compensation mechanism can refer only to a system of perimeter correction is unsubstantiated. For the reasons discussed above, the respondent's interpretation would lead to double counting of demand reduction and to demonstrably inefficient outcomes. Moreover, as explained in Section 4.1 and Appendix C, *all* TSC cashflows are "indirect" in that they flow from or to each market participant to or from each other market participant via the market operator; as further explained in Appendix C, in the Revised Phase 1 Solution suppliers of demand reduction customers are compensated at the Imbalance Price (PIMB), comprising the Supplier Compensation Price (PCOMP) from DSU aggregators plus an additional cashflow of (PIMB-PCOMP) funded by other suppliers. It follows that DSUs are treated exactly as they would be in Model 3, while suppliers in aggregate are compensated correctly, albeit the lack of explicit perimeter correction means suppliers of demand reduction customers may receive slightly more compensation, with this additional compensation being provided by other suppliers. The SEM Committee thus considers that balance responsibility and imbalance costs are apportioned better than in solutions in which there is no supplier compensation, with only minor consequences arising from a lack of explicit perimeter correction.

4.5. Calculating Supplier Compensation Price (Question 5)

The SEM Committee notes the comments on the calculation of the Supplier Compensation Price.

The SEM Committee notes the comments and proposals regarding the use of an average Day Ahead Market (DAM) price, and the use of a 90-day rolling average. The SEM's understanding is that the missing money problem for DSU arises due to the fact that the savings in the cost of purchasing from the supplier tend to reflect an average price[16]. If the customer were fully exposed to the Imbalance Price then the incentives for implicit demand response would be similar to the efficient incentives for explicit DSU demand response[17], and no missing money problem would arise. While the ideal level of PCOMP might be tailored to the specific terms of each supplier-customer arrangement, this would be burdensome to implement and monitor. The appropriate degree of averaging of the day ahead or Imbalance Price to use in PCOMP will be the subject of a separate consultation.

The SEM Committee notes the comment that PCOMP should be capped by the Reliability Option Strike Price. The SEM Committee's initial view is that this is not appropriate. As discussed in Section 4.1 and Appendix C, energy payments are the necessary incentives to provide the demand reduction and also cover the liability to make Difference Payments (in respect of which the DSU is also paid Capacity Payments). This mirrors exactly the arrangements as they apply to generators. PCOMP should reflect the long-run costs, as are likely reflected in the supplier-customer arrangement. This, too, will be consulted on in the separate consultation on PCOMP.

While the SEM Committee recognises that, in addition to providing efficient incentives, the arrangements need to comply with EU legislation, the objective of EU legislation is generally the same. The SEM Committee notes that Article 55A of the

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[16] Although some, particularly large, customers may on be time of use or dynamic tariffs.

[17] The SEM Committee recognises that explicit demand response can provide additional value to the system in terms of its dispatchability and the potential to provide system services.

amended EBGL in the ACER recommendation in March 2025 has been revised, and provides for compensation for "*balance responsible parties affected by demand response activation*" and for compensation to include "*defined costs*" which may include but are not limited to the "*costs of socialised charges which increase due to demand response activation*". The SEM Committee considers that a supplier compensation payment is consistent with these provisions.

The SEM Committee notes the comments that wide system benefits, such as lower wholesale prices, should be taken into account. However, the SEM Committee notes that this requirement is optional. The SEM Committee does not consider it appropriate to take benefits such as lower wholesale prices compared to a counterfactual into account. In the case of any producer in competitive market, it is not tenable to suggest that all consumers should pay, not the actual equilibrium price given the presence of that producer, but the hypothetical equilibrium price were that producer not there, with the difference between the actual and hypothetical equilibrium prices multiplied by total demand accruing to the one producer. Were that principle applied to all producers the effect would be the same as all consumers paying and all producers receiving the actual equilibrium price. Were this benefit to be afforded to all DSUs but not to other generators or other resources then DSUs would not be competing on an equal footing.

The SEM Committee notes the concerns regarding the applicability of supplier compensation to both intermittent and long-run DSUs. However, for the reasons discussed in Section 4.4, the SEM Committee does not agree that intermittent DSUs cannot "cover the amount". It recognises that lower than appropriate values of PCOMP would benefit DSUs while higher than appropriate values would be to their detriment, and that these effects would be more pronounced for long-run DSUs. The SEM Committee notes the suggestion that for long-run DSUs supplier compensation could be equal to energy payments. However, the SEM Committee considers that, mindful of respondents' comments that it is inappropriate to draw distinctions between different types of DSU, it is preferable that there is a consistent treatment across all DSUs.

The SEM Committee notes the comment that the "structure" could change from year to year. The SEM Committee agrees, as discussed in Appendix D, the structure could depend on what costs and charges would be incurred by “non-consumed” demand or avoided by demand reduction. The SEM Committee notes also the comment that the methodology should be flexible rather than explicitly defined in, say, the TSC. However, in the SEM Committee’s view, the lead-time for implementation of any methodology should depend on the complexity of the methodology, not on the industry document in which it is enshrined.

4.6. Supplier Compensation Price and ‘Long-Run' DSUs (Question 6)

The SEM Committee notes the comments that the Revised Phase 1 Solution would not have the correct incentive effect on long-run DSUs and the various comments that PCOMP being greater than the energy payment would disincentivise the DSU. The SEM Committee does not agree that this is necessarily the case. As discussed in Section 4.1 and Appendix C, in the SEM Committee’s view the basic condition for the DSU aggregator to make a demand reduction is that the energy payment (plus any additional cashflows) equals or exceeds the cost of making the demand reduction. This condition is the same condition that applies to generators, and hence would, in the first instance, put the DSU aggregator on an equal footing.

The SEM Committee recognises that if the saving in the costs of purchasing from the supplier is less than PCOMP then the incentive to reduce demand will be reduced, while if the saving is more then the incentive is increased. As discussed in Appendix D, if PCOMP reflects an average cost – Section 4.9 and Appendix D discuss what elements of cost should and shouldn’t be included – then it is possible that the incentive for demand reduction is increased at times of high prices, when demand reduction is most likely to be required, while it may be reduced at times of low prices, for example when renewable generation is high, when demand reduction is of little or no value. Providing PCOMP is set at an appropriate level then long-run DSUs will see both the increased and the reduced incentives, while intermittent DSUs will see the increased incentives only.

The SEM Committee notes the comments implying that the supplier compensation payment would be a penalty. However, for the reasons discussed in previous sections, the SEM Committee does not agree and is of the view that the supplier compensation payment is necessary to ensure that the incentives for demand reduction are on a comparable basis to generation. As such, the SEM Committee does not regard supplier compensation as a cost reduction measure other than to the extent that without it end customers would be funding demand reduction twice, once through energy payments and a second time through savings in the costs of purchasing from the supplier. The SEM Committee thus rejects the suggestion that it is seeking to qualify compliance with EU provisions by applying a spurious cost ‘reasonableness’ criterion.

The SEM Committee notes also the comment that the impact assessment had been carried out during a period of high prices and thus that “*the cost reduction measures ... are unnecessary”*. The SEM Committee does not agree. Regardless of the particular figures produced by the impact assessment, the SEM Committee considers that the principles of ensuring that there is no double counting and that incentives are appropriate remain the same.

4.7. Determining Non-consumed Energy (Question 7)

The SEM Committee notes that one respondent suggested further work on a solution involving voluntary agreement, while other comments were in favour of using ex post analysis. It notes comments that any voluntary agreement between suppliers and DSU aggregators would be “*a reversal of progress*”, and that “*smaller units*” might be at a disadvantage in negotiations. The SEM Committee agrees that it is desirable that suppliers should not have to consent to demand reduction arrangements, and the possibility of some voluntary arrangement was envisaged only as a stopgap pending the implementation of full perimeter correction.

The SEM Committee notes the comment that supported ex post analysis "*until an enduring solution is in place*”. However, the SEM Committee believes further work would be required to consider whether an ex post analysis solution could be found which would be easier to implement than an enduring solution and would be suitable as a stopgap measure.

The SEM Committee notes that the TSC specifies a number of criteria that each IDS in a DSU must meet and continue to meet. Also, the Grid Code has requirements concerning the provision of information including details of each IDS (including MPRNs), modes of operation, outages and the provision of SCADA signals. The SEM Committee will engage with the TSOs to determine whether these provisions can be used to determine measures of demand reduction and non-consumed energy and, if so, whether this can be done on a continuous basis or as ex post spot checks.

4.8. Categorising DSUs (Question 8)

The SEM Committee notes comments in favour of categorising DSUs. It notes the comment that “intermittent” DSUs face greater uncertainty than “long-run” DSUs and are more susceptible to the missing money problem. It notes and agrees with the comments that running hours would be substantially greater for long-run DSUs. It notes also the comment that long-run DSUs would normally be bidding negative but does not agree that this should necessarily be the case. As discussed in Section 4.1 and Appendix C, the SEM Committee believes that cost-reflective bid data should reflect the cost – likely to be positive – of making a demand reduction or generating on-site, and that negative avoidable costs may be arising as a result of double counting the cost of making the demand reduction and the saving in costs of purchasing from the supplier.

The SEM Committee notes the comments that there is no clear way to define a basis for differentiation between different DSUs and that delineation between modes of participation of units in the SEM is *“worrying, and fundamentally incorrect*”. The SEM Committee notes also the comment that the supplier compensation mechanism renders drawing a distinction unnecessary, provided that an appropriate PCOMP value or PCOMP methodology be determined. The SEM Committee agrees that if an appropriate PCOMP methodology and value are determined then the distinction should be unnecessary, and the one model can apply.

The SEM Committee notes also the comment that rather than a “dichotomy” between long-run and intermittent, there should be a graduation. With a single model the SEM Committee considers that this problem does not arise.

The SEM Committee notes the question as to whether it is necessary to categorise DSUs for the purposes of meter data provision. The SEM Committee does not anticipate such a requirement, although this would have to be confirmed during implementation.

4.9. Capacity Payments and Charges (Question 9)

The SEM Committee notes the comments that DSUs should be eligible for Capacity Payments and that it would be appropriate to include non-consumed energy in the charging base for Capacity Charges. It notes also the comment that *“If capacity is being procured, the person who supplied the capacity should not be paid a second time in the form of not having to pay capacity charges”* but that it seems to make more sense for capacity charges not to be levied on "*consumption that doesn't hit the system*" on the grounds that "*capacity is charged even on days or hours where there is unlikely to be any system stress*". The SEM Committee notes also the comments of respondents saying they do not see a suitable justification for "*taking away capacity payments*" and that suppliers can "*reposition their charges/tariffs to compensate*".

It is the SEM Committee's view that if demand reduction is paid for providing capacity but non-consumed energy is not charged then, as more capacity is provided by demand reduction, total capacity costs would be borne by the ever-shrinking tranche of non-reducible demand. If non-consumed energy is not charged for capacity then, in the same way that there can be double counting for energy, the SEM Committee considers that there could be double counting for capacity, i.e. both through payments for providing capacity and through savings in charges for capacity. The SEM Committee is thus inclined to the view that capacity charges should be considered for inclusion in the determination of supplier compensation. The SEM Committee does not agree that this would be "*taking away capacity payments*" or that this would be "*a major disincentive to explicit flexibility*", rather it would be avoiding capacity from demand reduction being rewarded twice through both DSU capacity payments and savings in capacity charges. The SEM Committee considers that, as well as being economically rational, this approach is not inconsistent with ACER’s NCDR recommendation.

Appendix D discusses in more detail.

4.10. Baselining (Question 10)

The SEM Committee notes comments that some form of baselining is necessary and a likely consequence of the NCDR. The SEM Committee notes another comment that it is important that DSUs should be performing to the same standards as other market participants. The SEM Committee notes also suggestions that the question in the Consultation Paper was disingenuous as it implied there is no baselining currently, and that the Consultation Paper implied that "*the response provided by DSUs to a dispatch can not be trusted*". The SEM Committee does not agree. While there may be provisions in the Grid Code, Grid Code baselining is not used in settlement, and the SEM Committee does not consider it unreasonable that DSUs be subject to a level of monitoring, scrutiny and financial discipline that is equivalent to that of other market participants.

The SEM Committee notes the comment that baselining should not be viewed as a long-term solution and that baselining should eventually be replaced by "more 'implicit' measures". The SEM Committee agrees that implicit demand response, where demand is exposed and can react to time of use price signals, avoids the problems of baselining. However, in the SEM Committee's view there remains a role for explicit demand response in providing a dispatchable resource for the system operator and in providing a number of system services.

The SEM Committee notes the comment that supplier compensation has no bearing on baselining methodologies. The SEM Committee agrees. In the Consultation Paper, it stated, "*the Phase 1 solution need not consist of a single package of changes, all of which need to be implemented in one go, but can involve a series of changes most of which can be implemented individually, as and when appropriate.*" The SEM Committee will engage with SEMO, TSOs and other relevant parties to consider whether any initiatives could be progressed in advance of an enduring Phase 2 solution.

4.11. Sub-metering and SCADA (Questions 11 and 12)

The SEM Committee notes the comments about the use of sub-metering, which generally expressed support for the importance of sub-metering. The SEM Committee agrees and agrees that sub-metering will help verifying demand response and may also enable "*inaccessible loads ... to become flexible*".

The SEM Committee notes the comments that sub-metering would be burdensome for the Meter Data Providers, which would be required to maintain connections with a potentially large number of meters and to "*accommodate non-standardised meter* *configurations*". However, the SEM Committee considers it to be not unreasonable that Meter Data Providers assess the configuration and metering of sites and be required to define suitable meter aggregation rules to enable effective settlements.

The SEM Committee notes the comments regarding the use of SCADA data. In particular, it notes comments that SCADA data may not provide "revenue grade" data, but that it may form part of a solution, particular one which is interim. The SEM Committee notes comments that there may be difficulties in correlating SCADA with supplier unit registrations. However, the SEM Committee's view is that this would be a problem only with solutions where explicit perimeter correction is implemented, and that for the Revised Phase 1 Solution, SCADA data might be able to provide verification of the demand response provided, which improves on the current arrangements that deem the delivered demand response to be equal to the instructed demand response.

The SEM Committee notes also that EU Regulation 2024/1747 introduced the concept of dedicated measurement devices such that these may have to be incorporated into settlements infrastructure. The SEM Committee will engage with the TSOs and MDPs to ascertain whether SCADA data could be employed in a cost-effective manner in advance of an enduring Phase 2 solution.

4.12. Aggregated Generator Units (Question 13)

The SEM Committee notes the comments that DSUs can be facilitated through AGUs, but that this may be undesirable to DSU operators given the additional burden of compliance requirements for on-site generation, such as environmental regulations or licensing. The SEM Committee notes also the comment that there may be too many potential configurations and that arrangements need to be simplified. While the SEM Committee has no wish to limit the routes to market for market participants, it is also the case that there should not be significant differences in the treatment of any given set of assets depending purely on how they are registered. In particular, environmental regulations and licensing requirements should not depend on the particular registration under the TSC. The SEM Committee believes there may be some merit in future developments and modifications giving consideration to the possibility of rationalising the arrangements, rather than continually adding to them.

The SEM Committee notes the comment that AGUs and DSUs are fundamentally different participation methodologies. In the SEM Committee's view, AGUs and DSUs - when implemented using on-site generation - are very similar, and it is unclear why outcomes should be significantly different. It notes the comment that AGUs require an equivalent of MEC, which brings additional costs. Again, the SEM Committee's view is that MEC, being a property of a connection agreement, should depend on the physical configuration of the assets rather than how they are registered under the TSC.

The SEM Committee notes the comment that there may be gaps in the framework for AGUs in Ireland, and agrees that changes to address any such gaps should be considered. The SEM Committee isn't clear why retail market systems in Ireland do not already provide for AGUs but considers that steps should be taken to address any problem areas.

The SEM Committee notes the comment that arrangements similar to those for Autoproducers may be appropriate, and the comment that Dispatchable Consumption may also be an appropriate model. As stated above, the SEM Committee agrees that there may be potential for simplification.

4.13. Other Issues (Question 14)

The SEM Committee notes the comment that extending the enduring solution into a Phase 1 and Phase 2 adds further complexity. However, in the SEM Committee's view this was always the intention, and the Consultation Paper only discussed the Revised Phase 1 solution as a potential replacement to the previous Phase 1 solution. The SEM Committee notes also the reference to "Model 3", although it considers that Model 3 was discussed in the Consultation Paper not as an intended alternative to the enduring solution but as a means to demonstrate the rationale for the Revised Phase 1 Solution. There was no intention in the Consultation Paper to re-open the Phase 2 solution. That said, the SEM Committee does not agree that the Revised Phase 1 Solution is complex. In the SEM Committee's view, while some process would be required to determine PCOMP, the "additional cashflow" consists simply of an additional term in the calculation of existing payments to DSUs.

The SEM Committee notes the comment about implementing changes as quickly as possible, particularly where these do not require system releases. The SEM Committee agrees that this is desirable. However, it is difficult to conceive of changes that won't involve any system development, and hence it is not obvious that there will be any 'short cuts'. As with most developments, industry looks to SEMO and the TSOs to progress changes as quickly as possible. The SEM Committee notes also the comment concerning initiatives in the "flexibility market" and agrees that engagement concerning these will be helpful.

The SEM Committee notes the comment requesting implementation timelines, DSU performance analysis, cost-reflective Complex COD and alignment with the ACER recommendations on the NCDR. As soon as implementation timelines become available, the SEM Committee intends to make these available, while the SEM Committee believes that the issue of transparency as regards DSUs may need to be reviewed. The SEM Committee agrees that Complex COD needs to be cost-reflective, and the MMU will continue to review this matter, and will issue guidance. Lastly, the SEM Committee has been following the development of the NCDR, and has sought to ensure that any proposals are consistent with it.

The SEM Committee notes the comment that the Revised Phase 1 Solution is placing "penalties" on DSUs. As discussed in Sections 4.1 and Appendix C, the SEM Committee rejects this assertion, and considers that supplier compensation is a necessary component of ensuring that arrangements are economically efficient, do not double count demand response, and place DSUs on an equal footing with other market participants.

The SEM Committee notes the comment that the consultation failed to mention the historic payment of energy payments. When there is clarity on the arrangements going forward, the SEM Committee will, as requested, engage with industry on how this matter can be resolved.

4.14. Negative Demand Response (Question 15)

The SEM Committee notes comments that DSU's being paid not to reduce demand is no less valid an outcome that a generator being paid not to generate, that negative demand response has been well documented and discussed, and that the MMU has reviewed these behaviours. The SEM Committee's view is that the situation is not so straightforward. When a generator is paid not to generate it is because it has sold energy in the ex ante and:

(i) is buying it back at a lower price in the balancing market (generally as a result of a shift in the balance of supply and demand); or

(ii) it is being required not to generate and is buying the energy back at its avoidable cost of production and so retains the lost inframarginal rent it would have earned had it run at its Final Physical Notification (FPN).

In the SEM Committee's view, the situation for demand is not as straightforward. If a DSU is instructed to reduce demand reduction then, in effect, the customer has bought demand at one price through its supplier, sold it back to the system at a higher ex ante price, and then is buying it a second time at the lower decremental price.

The SEM Committee does not accept that this issue has been *"well documented and discussed".* SEM-18-158 discussed negative offer prices, rather than negative demand reduction, and merely acknowledged that negative offer prices were being seen and declared an intention to monitor them, while the FRR for Mod_02_23 stated only that the TSO was aware the MMU was reviewing data. Moreover, SEM-18-158 was published before the current SEM was implemented.

The SEM Committee notes the comment that the capacity market should pay for the capability to increase demand. The SEM Committee disagrees. The purpose of the capacity market is to address resource adequacy concerns, and it is difficult to see how increasing demand meets this purpose. Furthermore, it is unclear how such a proposal would comply with rules for capacity mechanisms set out in EU Regulation 2019/943.

The SEM Committee notes comments which expressed concerns and made reference to the development of arrangements for dispatchable consumption. The SEM Committee recognises that there are potential issues that can arise with price-sensitive demand. To date, demand on the system has generally been exposed to a common price. Negative demand response and dispatchable consumption both widen the scope for price-sensitive demand. While there are efficiency gains to be had, there is also the possibility of certain system costs falling increasingly on other demand, particularly domestic demand. There are also potential interactions with priority dispatch policy, which potentially could result in the TSOs dispatching demand at large negative prices, paid for by all other demand. The SEM Committee thus considers that caution is required.

4.15. Shutdown Costs and Decremental Prices (Questions 16 and 17)

The SEM Committee notes the comments that the shutdown cost for a DSU is governed by the Bidding Code of Practice and that any additional requirements would stifle the operation of aggregated units. The SEM Committee agrees. However, it is the intention the SEM Committee not to specify requirements additional to the BCOP but to understand and clarify how the BCOP should apply.

The SEM Committee notes the comment that a conventional power plant does not receive different start-up costs depending on whether they are instructed to minimum or maximum output. This is because a conventional power plant goes through the same start-up, incurring the same costs, regardless of whether it is then dispatched to minimum or maximum output. It is the SEM Committee's understanding that, in contrast, a DSU made up of several IDSs may call upon only one IDS if a small demand reduction is instructed, incurring only one IDS shutdown cost, but may call on multiple IDSs if a large demand reduction is instructed, incurring multiple IDS shutdown costs. Thus, it is not cost reflective to aggregate the shutdown costs for all the component IDSs into a single shutdown cost, which is deemed to be incurred regardless of whether a small or large demand reduction is instructed, or to maintain the DSU shutdown cost at the same value even after some IDSs within the DSU become unavailable. The SEM Committee recognises that the SEM systems do not provide for partial shutdown costs to be incurred in stages, as the output of a unit is increased. The SEM Committee believes that it is thus relevant to question whether a better approximation than aggregating all the IDS shutdown costs into a single shutdown cost is to spread the shutdown cost across the output of the IDS to give an increased incremental price.

The SEM Committee notes the comment that there is a lack of transparency for IDSs. The SEM Committee agrees that there is less transparency than there is for generating units, where the behaviour of specific assets can be ascertained. In the

SEM Committee's view, it is for consideration how, as the system comprises more and more distributed resources, transparency is to be maintained.

The SEM Committee notes and agrees with the comment that *"decremental prices should be tied to real costs with negative bids allowed in specific justified costs".* It notes also the comments that *"the calculation of decremental bid prices is determined by the Trading & Settlement Code".* However, while the TSC provides for the submission of these prices, the prices themselves are as determined and submitted by the market participant, while it is the Bidding Code of Practice that governs what prices market participants can submit.

The SEM Committee notes the comments that decremental bid prices may be different for long-run and intermittent DSUs, and that decremental bid prices for demand reduction *"should be calculated by considering a range of factors".* In the SEM Committee's view, if there is a positive incremental price to making a demand reduction, due to the positive cost of on-site generation or the lost utility of reducing consumption, it is likely that the decremental price is positive, also. The SEM Committee acknowledges there could be circumstances in which decremental prices could be negative but these are likely to be the exception rather than the rule, and would expect such circumstances to be justified to the MMU.

The SEM Committee notes and agrees with the comment that DSUs should comply with REMIT[18].

4.16. Grid Code Availability Declarations (Questions 18 and 19)

The SEM Committee notes comments that the Grid Code requires DSUs to have a capacity of at least 4MW but not that there is any requirement to declare an availability of at least 4MW. The SEM Committee recognises that the 4MW criterion appears in the definition of Demand Side Unit, which is defined as having a "Demand Side Unit MW Capacity of at least 4 MW", but that there's no explicit requirement to

[18] The SEM Committee notes that ACER considers that a contract for the provision of demand response services qualifies as a wholesale energy product pursuant to Article (2)(4)(a) of REMIT and has to be reported under Article 8 of REMIT, and that, pursuant to Article 3(1)(a)(ii) of Commission Implementing Regulation (EU) No 1348/2014, contracts involving a customer providing demand response services to a supplier and/or an aggregator should be reported on a continuous basis. See "Questions & Answers on REMIT, 30th Edition", ACER, 12 March 2025.

offer "Demand Side Unit MW Availability" of more than 4MW. However, the SEM Committee notes that an Outage in relation to a Demand Side Unit is defined in the Grid Code as *"a total or partial change in Availability such that the Demand Side Unit is unavailable to achieve its full Demand Side Unit MW Capacity".* It is thus the SEM Committee's understanding that the availability of Demand Side Unit should be at least equal to 4MW unless an outage has been requested and included in the Committed Outage Programme, under OC2 of the Grid Code. The SEM Committee does not seek to impose additional requirements on DSUs but, equally, it is concerned that DSUs meet the requirements that are in place and that the requirements on DSU are not relaxed to the point that their value to the system is compromised.

The SEM Committee notes comments concerning the rounding of DSU availability declarations. It is the SEM Committee's view that the Grid Code requires that availability declarations are rounded down to the nearest MW, although it recognises too that this requirement may be onerous for DSUs and any other small resources, and that the forthcoming NCDR may require improved resolution of availability declarations to be facilitated.

4.17. EU Legislation

The SEM Committee notes the comments of a respondent regarding inaccurate statements in the Consultation. The SEM Committee does not agree with these comments. Specifically:

(1) As discussed in earlier sections, the SEM Committee has used the terminology "long-run" and "intermittent" to recognise that different DSUs will behave differently in the market. As noted by other respondents, this is analogous to the terms "baseload" and "peaking" that are frequently applied to generation. As discussed in Section 4.8, it is desirable that a single model be used to handle as wide a range as possible of modes of participation in the market, and this is one of the ideas behind the Revised Phase 1 Solution that was offered for discussion in the Consultation Paper.

(2) In the current TSC, Metered Quantity (QM) for DSUs is deemed to be equal to the Dispatch Quantity (QD), regardless of the actual response of the DSU to the

dispatch instruction. This is not the case with generators, and hence the DSU is not on an equal footing.

(3) The SEM Committee does not agree with the comments regarding Mod_02_23:

(i) The respondent suggests that the Modification Proposal was approved by the Modifications Committee and by the SEM Committee. This is incorrect. First, the Modifications Committee does not have the power to approve Modification Proposals. Second, approval by the SEM Committee was subject to impact assessment and hence was not given prior (or subsequent) to receipt of the impact assessment.

(ii) the Final Recommendations Report, minus impact assessment, may have described a verbal report from the TSO of an additional cost of €60-65m, with only a small number of units receiving most of this, "due to their specific market conditions". However, until receipt and review of the impact assessment, it was not clear to the SEM Committee that this cost would be incurred mostly in circumstances where there isn't any missing money problem. Hence, while energy payments may be due to DSUs, these are instead of, not additional to, savings in costs of purchasing from the supplier.

(iii) The RAs' Market Monitoring Unit may have been reviewing the bidding behaviours of DSUs but this has not focussed on the double-counting issue.

With regard to EU provisions, while financial compensation under Article 17(4) of the Directive may be optional, the SEM Committee does not accept that this implies that such compensation can be implemented only after the implementation of energy payments.

Nor does the SEM Committee accept that it is "*attempting to implement a measure such that some DSU would not be granted energy payments in any meaningful way due to the costs associated with doing so*". On the contrary, the SEM Committee believes that it has developed and consulted upon workable arrangements for providing energy payments to DSUs under all circumstances in a way that appropriately incentivises demand response, ensures that demand response is efficiently dispatched and ensures that demand response participates on an equal footing with other market participants, as required by EU Regulation 2019/943.

The SEM Committee does not agree that Mod_02_23 is "*an approved measure*".

4.18. Implementation

The SEM Committee notes the comments regarding implementation. The SEM Committee understands that the implementation of a system for perimeter correction poses a significant challenge to the parties involved. As regards the Revised Phase 1 Solution, the SEM Committee understands that additional work would be required to develop and implement a modification. The SEM Committee notes the comment that the implementation would not be trivial. It agrees to the extent that few modifications are regarded as trivial but considers that the Revised Phase 1 Solution is straightforward. The SEM Committee recognises that there are other SEM developments taking place but considers SEMO able to resource market developments to support the energy transition.

The SEM Committee notes that the TSO/DSO Operating Model is being progressed. The SEM Committee's understanding is that, while explicit perimeter correction will impact TSO/DSO/MDP/SEMO systems, the Revised Phase 1 Solution would have minimal impact.

5. Proposed Decisions

Proposed Decision 1 (Revised Phase 1 Solution): The SEM Committee proposes that a Revised Phase 1 Solution be implemented, whereby DSUs receive energy payments on the same basis as Generator Units, subject to supplier compensation payment paid by each DSU equal to the DSU Metered Quantity multiplied by the Supplier Compensation Price.

Proposed Decision 2.1 (Supplier Compensation Price): The SEM Committee will publish a consultation paper on the determination of the Supplier Compensation Price, this consultation to run in parallel with this proposed decision paper.

Proposed Decision 2.2 (Capacity): The consultation on Supplier Compensation Price will consider the treatment of capacity charges and other avoidable costs.

Proposed Decision 2.3 (Dynamic Retail Tariffs): The consultation on Supplier Compensation Price will consider the impact of dynamic retail tariffs.

Proposed Decision 3 (Negative Demand Response): The treatment of negative demand response will be considered further in a separate workstream, along with the development of dispatchable consumption units.

Proposed Decision 4 (Bidding): The SEM Committee will request the Market Monitoring Unit to review the Bidding Code of Practice as it applies to Demand Side Units and the appropriate methodology for determining COD. This will consider what costs it is appropriate to include and the appropriate treatment of IDS shutdown costs.

Proposed Decision 5 (Baselining): The SEM Committee will engage with SEMO, the TSOs and industry to consider what baselining developments could be progressed in advance of an enduring Phase 2 solution.

Proposed Decision 6 (SCADA): The SEM Committee will engage with SEMO, the TSOs, MDPs and industry to consider whether SCADA data could be employed in a cost-effective manner in advance of an enduring Phase 2 solution, and whether this and/or other data could be used to determine measures of demand reduction and non-consumed energy either on a continuous basis or as ex post spot checks.

Proposed Decision 7 (Grid Code Availability Declarations): The SEM Committee will engage with the TSOs regarding a review of the Grid Code provisions for Demand Side Units and their enforcement.

Proposed Decision 8 (AGUs): The SEM Committee will review the regulatory framework of Aggregated Generator Units in the SEM to identify any aspects which cause inappropriate disincentives to the registration of AGUs for distributed generation.

6. Next Steps

The SEM Committee intends to publish shortly a consultation paper on the determination of Supplier Compensation Price. The SEM Committee intends to conclude on these proposed decisions and on the determination of Supplier Compensation Price together.

Appendix A: List of Respondents

The respondents to the Consultation Paper were:

1. Aughinish Alumina Limited
2. Bord Gáis Energy
3. Demand Response Association of Ireland
4. Energy Association of Ireland
5. EirGrid plc and SONI Limited
6. Energia Group
7. ESB Generation and Trading
8. ESB Networks
9. Energy Trading Ireland
10. Federation of Energy Response Aggregators
11. iPower
12. NIE Networks Limited
13. Pinergy
14. RedoxBlox
15. VIOTAS

Appendix B: Consultation 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.

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

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.

Q4: 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. Do you consider that this will allow DSUs to compete on an equal footing, without undue disadvantage or undue advantage, compared to generators. Please explain your view.

Q5: How do 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.

Q6: 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.

Q7: 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, or by ex-post analysis of demand reduction dispatch decisions? Please explain your views

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?

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.

Q10: Do you consider that some form of baselining is needed? Would appropriate supplier compensation payment arrangements affect this? 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.

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

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

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.

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 your view.

Q15: What are you views about negative demand response? Do you consider the supplier compensation payment arrangement will work for negative demand response? Do you think there is any potential for perverse outcomes and undue discrimination between customers? Please explain your view.

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

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.

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.

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.

Appendix C: More on Demand Reduction Cashflows

A number of models for demand reduction cashflows were considered in the Consultation Paper.

Model 1 (see Figure 1) showed an arrangement without energy payments, whereby the only reward for demand reduction takes the form of the customer's savings in the cost of purchasing power from the supplier. It was acknowledged that at times when the system is tight and market prices are high, it is possible that these savings would not cover the cost of more expensive demand reduction actions, creating an incentive to reduce the availability of such demand reduction at precisely the times when it is most needed.

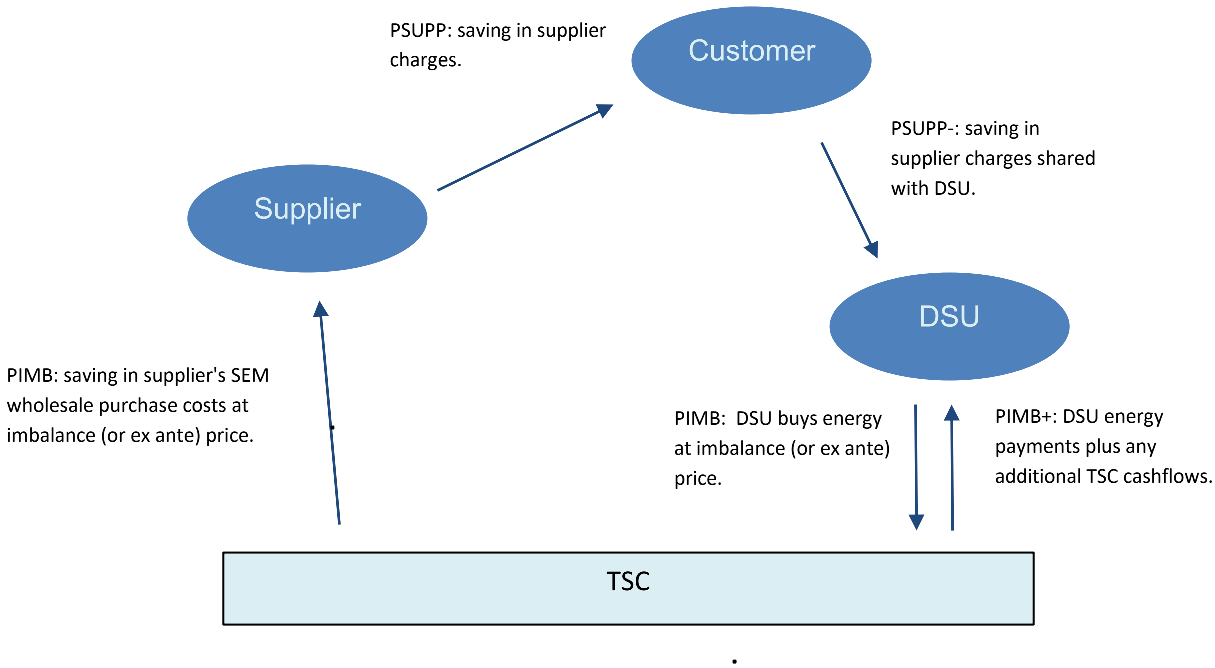

Figure 1: Model 1 (No DSU Energy Payment)

Model 2 (see Figure 2) showed an arrangement with energy payments to the DSU aggregator, and with 'perimeter correction', whereby the supplier is required to purchase the 'non-consumed' energy that the DSU sells back to the system as demand reduction. However, a supplier is unlikely to want to supply a customer unless it can bill the customer for the non-consumed energy. Likewise, the customer is unlikely to agree arrangements with a DSU aggregator unless, when a demand reduction occurs, the DSU aggregator compensates the customer for the cost of the non-consumed energy through the revenues it shares with the customer. Note that these diagrams show the *change* in cashflows as result of activating the demand reduction, and hence the supplier buying the non-consumed energy and charging the customer is represented by the being no *change* in these cashflows.

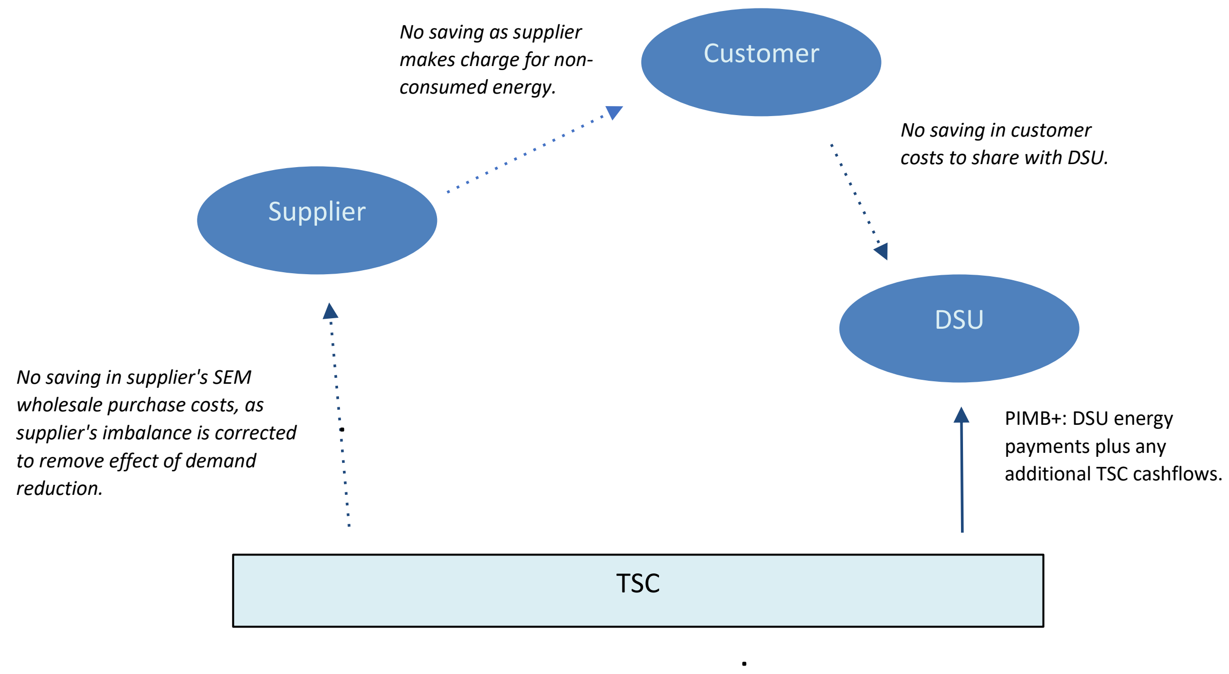

Figure 2: Model 2 (DSU Energy Payment)

Figure 3 below shows a modified version of Model 3. The only change from the Consultation Paper is to show that the supplier compensation payment would not be a payment under a bilateral agreement between the DSU aggregator and the supplier but takes place via the market operator under the terms of the Trading and Settlement Code.

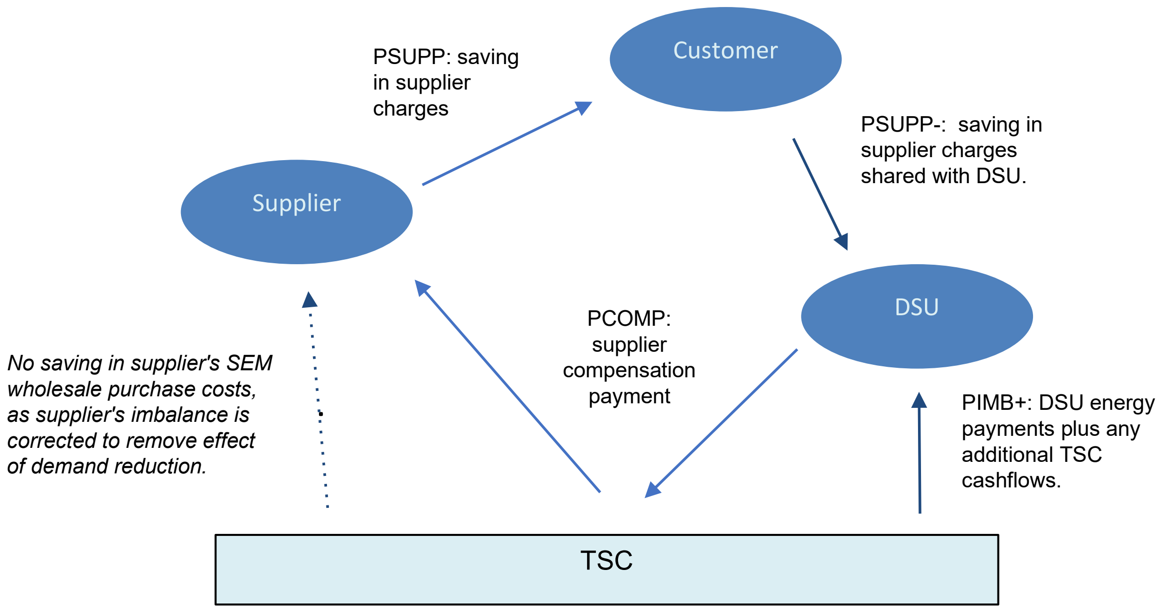

Figure 3: Model 3 (DSU Energy Payments showing Supplier Compensation via TSC)

Figures 4a to 4c show further detail of the Revised Phase 1 Solution. How arrangements are structured as between the customer and the DSU aggregator are a private matter to be negotiated between the two. For ease of exposition, Figure 4a shows the cost of making the demand reduction – shown here to be an on-site generator – as being covered directly by the DSU aggregator. It shows clearly how the cost of the demand reduction (priced at PCHP) is covered by the energy payments (priced at $PIMB^{+}$) from the market, in the same manner as would be case were the demand reduction a generator, while the supplier compensation payment (priced at PCOMP) corresponds with the value of the saving in purchase costs from the supplier (priced at PSUPP). (Note that if any proportion of the demand reduction is sold in the ex ante market then the energy payments will be at a combination of the Imbalance Price (PIMB) and the ex ante price.)

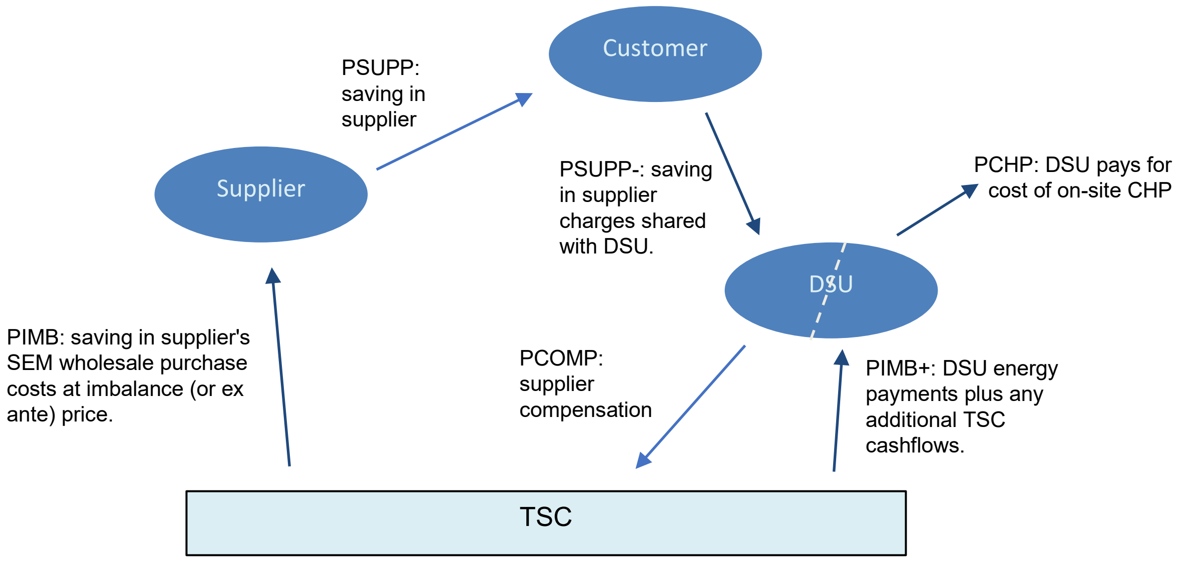

Figure 4a: Revised Phase 1 Solution showing DSU bearing cost of demand reduction

In Figure 4b, the customer bears the cost of making the demand reduction (as we understand is likely to be the case) and so the cost of the demand reduction is met by the DSU aggregator indirectly, via the customer. However, the situation is unchanged from Figure 4a, in that the cost of making the demand reduction is met out of the energy payments to the DSU aggregator, while PCOMP corresponds with PSUPP. Thus, in the SEM Committee's view, with PCOMP appropriately set, the DSU aggregator is competing on an equal footing with generators.

Figure 4c shows that the imbalance payment to the supplier can be split into two components:

(i) a payment at PCOMP via the Market Operator from the DSU, plus
(ii) an additional payment from other suppliers at (PIMB - PCOMP).

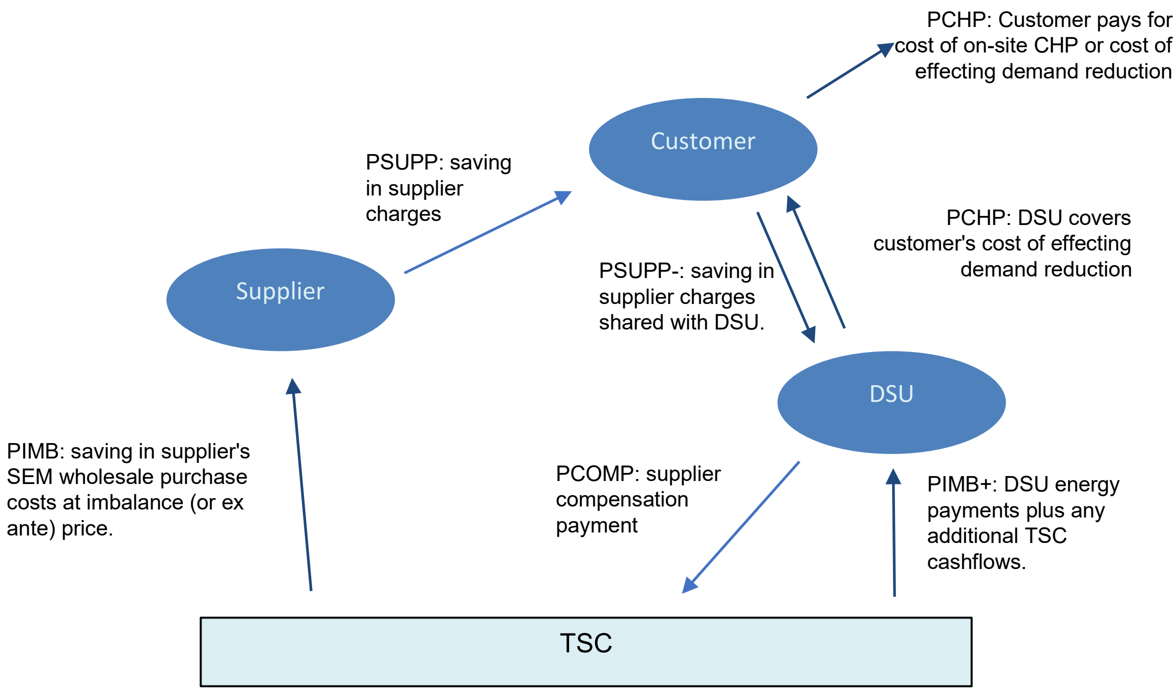

Figure 4b: Revised Phase 1 Solution showing customer bearing cost of demand reduction

Thus, Figure 4c shows that the only difference between the Revised Phase 1 Solution and Model 3 is the additional payment from other suppliers of (PIMB - PCOMP) on any demand reduction. Moreover, compared to Model 3, the non-consumed energy manifests itself as an imbalance, compensated at the combination of PCOMP and (PIMB-PCOMP). Thus, the perimeter correction is in effect carried out implicitly rather than explicitly, albeit with the addition of the additional cashflow at (PIMB-PCOMP).

In the SEM Committee's view, it might be preferable to not have the additional payment at (PIMB-PCOMP). However, the benefit to other suppliers is that the cost of this additional payment will be significantly less than the cost of double counting demand reduction through both energy payments to DSU aggregators without perimeter correction and supplier compensation Meanwhile, with PCOMP appropriately set, DSU aggregators compete on an equal footing with generators and are in exactly the same position financially as in Model 3.

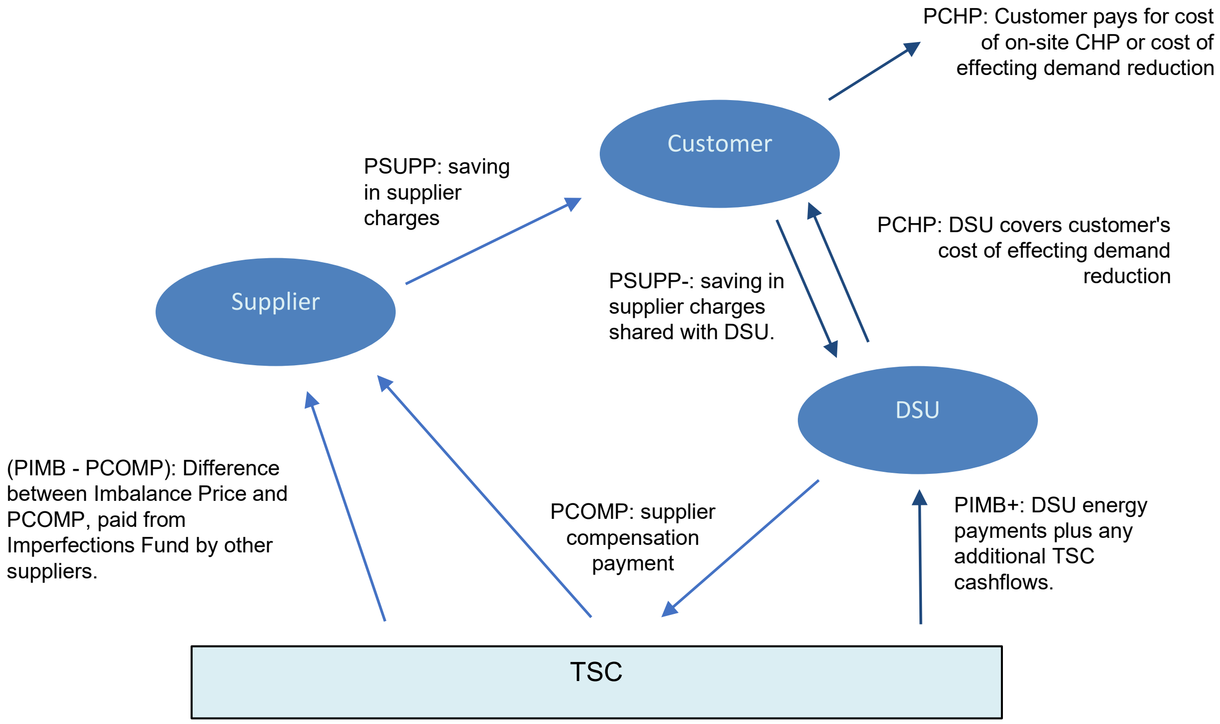

Figure 4c: Revised Phase 1 Solution showing equivalence to Model 3

Appendix D: Supplier Compensation Price (PCOMP) Methodology

The Revised Phase 1 Solution requires the setting of a Supplier Compensation Price, PCOMP. While the methodology for determining PCOMP will be subject to a separate consultation, this appendix sets out some of the arguments that should inform the PCOMP methodology, and which will be included in the consultation.

The basis for setting PCOMP is that in Model 2 "perimeter correction" is applied to the metered quantities of suppliers of demand reduction customers, such that the supplier is required to purchase the "non-consumed energy" that is being sold back to the system as demand reduction by the DSU aggregator. In Model 2, it is expected that the supplier will bill the customer for the non-consumed energy, and we would expect the customer to seek to recover the costs of this non-consumed energy from the energy payments and other revenues that the DSU aggregator receives from the market. Instead of the cashflow going via the customer, in Model 3 the cashflow goes from the DSU aggregator to the supplier (via the market operator) without the customer being involved. However, there is no economic reason in Model 3 for the magnitude of the cashflows being different to Model 2. Hence PCOMP should reflect the additional charges the supplier would make on the customer, which the customer would look to be reflected in the terms with the DSU aggregator.

Component costs that go to make up the supplier's charges on the customer include:

- Energy
- Capacity
- Network Charges
- Imperfections Charges
- Market Operator Charges
- System Services Charges
- Hedging costs
- Supplier margin
- Supplier costs
- Taxes
- Losses (DLAF)

A consequence of explicit perimeter correction is that the supplier is billed by SEMO for the non-consumed energy through a positive addition to the supplier's imbalance, such that:

(1) a supplier that is short, i.e. for which the magnitude of its physical consumption (a negative quantity) exceeds the magnitude of its contractual position leaving a negative imbalance, is made more short, by dint of its physical consumption being made more negative; or

(2) a supplier that is long, i.e. for which the magnitude of its physical consumption (a negative quantity) is less than the magnitude of its contractual position leaving a positive imbalance, is made less long, again by dint of its physical consumption being made more negative[19].

From the perspective of the system, the additional (non-consumed) energy that is thereby sold to the supplier corresponds with the demand reduction purchased from the DSU aggregator. Without this perimeter correction, the remaining uncorrected metered demand will bear the cost of more than its fair share of generation. To illustrate, consider a system with 1000MW of demand and 1000MW of generation, with no demand reduction. If 100MW of generation is then re-registered as demand reduction and perimeter correction is not applied then 900MW of metered demand will be required to bear the cost of 1000MW of generation. In the SEM, this cost would be borne through 900MW of generation bought directly by the 900MW of demand (ether ex ante or through the balancing market) plus 100MW paid for through energy payments funded by the Imperfections Charge. In effect, the additional cost of the 100MW funded through the Imperfections Charge is a cross-payment from the 900MW of demand bought from suppliers to the 100MW of demand that is satisfied by the 100MW demand reduction. With perimeter correction, the supplier will be charged for non-consumed energy, such that the energy payments to the DSU aggregator is not borne by other suppliers through the Imperfections Charge.

[19] We ignore the case where a supplier that is slightly long is made slightly short, but the principle is the same.

In contrast, if network charges are charged to the supplier on the uncorrected metered demand then there is no double counting and the savings from the reduced use of the network accrue directly and only to the supplier. In this case in Model 2 there would be no charge to the customer for network charges on the non-consumed energy and so the customer would not need to recover these costs through compensation from the DSU aggregator. Hence, in this case in Model 3, it would seem inappropriate to reflect these network charges in PCOMP.

Addressing some of the components of supplier charges:

- Energy: As discussed above, the component of supplier charges reflecting energy should be included in PCOMP. Further detail is discussed below.
- Capacity: The same arguments that apply to energy apply also to capacity. If demand reduction is paid for providing capacity then the supplier should be charged for capacity on the non-consumed energy. Otherwise, using the same example, 900MW of demand will have to bear the cost of capacity payments to 1000MW of capacity[20].
- Network charges: If the supplier is charged network charges only for the uncorrected, reduced demand, then it would seem appropriate that PCOMP not reflect these network charges.
- Imperfections Charges: If the supplier is charged Imperfections Charges on the non-consumed energy it may be appropriate to reflect these in PCOMP.
- System Services charges: If the supplier is charged system services charges on the non-consumed energy it may be appropriate to reflect these in PCOMP.

These and other costs, including Market Operator charges, hedging costs, supplier margin, supplier costs, taxes and losses (DLAFs), will be discussed in the consultation.

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[20] For simplicity, we ignore here the derating of capacity to reflect less than 100% reliability, and that more than 1MW of capacity resources is bought to secure each 1MW of demand.

Measure of Energy Prices

A further consideration is whether PCOMP is a constant value or whether it should include time-of-use or dynamic elements. In brief:

(a) if PCOMP is dynamic and fully reflects varying wholesale market prices while the supplier supplies the demand reduction customer at a flat tariff then, with perimeter correction, a substantial proportion of the benefits of demand reduction would accrue to the supplier and the demand reduction may be under-incentivised; whereas

(b) if PCOMP is a constant value while the supplier supplies the customer on a time-of-use or dynamic tariff then, with perimeter correction, the supplier would be under-compensated while the demand reduction may be over-incentivised.

Hence a dynamic PCOMP value is likely either to fairly compensate or under-compensate demand reduction, while a constant PCOMP is likely either to fairly compensate or over-compensate demand reduction.

This issue will be discussed further in the consultation paper.

Appendix E: Impact Assessment

The impact assessment undertaken in relation to SEM-22-090 identified energy payments of €56m, of which €52m were in respect of long-run DSUs without incentivising any change in behaviour that results in benefits for the system and to electricity customers as a whole.

It seems likely that, depending on the determination of PCOMP, the €52m cost would be largely removed, while the remaining €4m would be reduced. Notwithstanding this reduction in costs, it is the SEM Committee's view that demand reduction would be appropriately incentivised. This could promote additional demand reduction, which would tend to increase the €4m cost but produce commensurate benefits for the system.

Appendix F: Relevant Documents

1. "State aid No. SA.44464 (2017/N) – Ireland – Irish Capacity Mechanism, C(2017) 7798 final, European Commission, 24 November 2017.
2. “Information Note on Demand Side Unit Bidding”, SEM-18-158, 28 September 2018.
3. “Capacity Remuneration Mechanism (CRM) DSU Compliance with State Aid Consultation Paper”, SEM-19-013, 15 March 2019.
4. “Regulation (EU) 2019/943 of the European Parliament and of the Council on the internal market for electricity", 5 June 2019.
5. "Directive (EU) 2019/944 of the European Parliament and of the Council on common rules for the internal market for electricity and amending Directive 2012/27/EU", 5 June 2019.
6. “Single Electricity Market Capacity Remuneration Mechanism DSU Compliance with State Aid. Decision Paper”, SEM-19-029, July 2019
7. "Mod_17_19: DSU State Aid Compliance Interim Approach", SEMO, 21 November 2019.
8. "Enduring Solution to Enable Energy Payments in the Balancing Market for DSUs – A Consultation", SEM-22-036, 4 July 2022.
9. "Enduring Solution to Enable Energy Payments in the Balancing Market for DSUs – Decision Paper", SEM-22-090, 25 November 2022.
10. “Final Recommendation Report: Mod_02_23 DSU Energy Payments”, SEMO, 22 February 2023.
11. “Demand Side Units: A Revised Phase 1 Solution for Energy Payments and Other Issues” SEM-24-046, 23 August 2024.
12. "Recommendation No 01/2025: Network Code on Demand Response", ACER, 7 March 2025.
13. "Questions & Answers on REMIT, 30th Edition”, ACER, 12 March 2025.