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

Consultation Paper SEM-24-046

A submission by EirGrid plc. & SONI Ltd.

25 October 2024

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1 Executive Summary

EirGrid plc. (EirGrid) and SONI Ltd. (SONI) welcome the publication of consultation SEM-24-046, Demand Side Units: A Revised Phase 1 Solution for Energy Payments and Other Issues (the Consultation Paper) and the opportunity to respond to the consultation. This response is submitted by EirGrid and SONI in their capacities as TSOs and MOs for Ireland and Northern Ireland respectively (herein after referred to as 'EirGrid and SONI').

EirGrid and SONI recognise the contribution of Demand Side Units (DSUs) to the power system and their role in the transition currently underway, as well as the benefits of demand response in potentially alleviating some of the security of supply concerns facing the power system. EirGrid and SONI support potential initiatives that could help enable demand side response to further develop to meet power system operational and wholesale market needs.

We support any measure that will encourage more demand side availability. In this context, as part of the Sharping Our Electricity Future roadmaps, future power system planning is aligned with requirements from the Irish Government and the CRU for 20-30% demand side flexibility by 2030 and DSUs will be a key element of this requirement. We emphasise that the availability of DSUs must be predictable and reliable. The uncertainty of DSUs' availability remains a challenge and a concern which has been raised with the Regulatory Authorities (RAs) on a number of previous occasions. Reviewing the most recent EirGrid and SONI Monthly Availability Reports, the 365 Day Rolling Availability of DSUs is approximately 20% of their installed capacity. Based on this, there is considerable room for improvement in the contribution of DSUs in supporting a secure power system. This can be developed through reward mechanisms which are aligned with actual performance.

EirGrid and SONI agree that there is a need to address the missing-money problem for high-cost DSUs that provide demand reduction at times of scarcity when wholesale prices are expected to be higher. As these DSUs may be operating at a loss, we appreciate the need for incentives to maximise availability, rather than minimise availability at these times, when demand reduction is most needed. However, it is important when considering the solution for this issue that it is done in the context of emerging technologies and developments to ensure there are no unintended consequences, for example that any decision does not have the potential for unintended impacts for Large Energy Users with on-site generation seeking to participate in the SEM.

EirGrid and SONI feel that it is important to highlight the complexity of the solutions being proposed for Phase 1 and Phase 2. While we recognize the benefits of the revised Phase 1 solution, it is also important to recognise that this is not a straightforward change. This solution involves additional design and implementation work for which there is a cost and timeline to be considered. In relation to a Phase 2 solution, as we noted in our previous responses, this is significantly dependent on data systems and transfers that do not exist within the current wholesale market design and systems and will involve significant time and investment to deliver. Particularly, if the Model 3 approach is preferred over Model 2 as described, the scale of the changes will result in a multi-year, cross industry implementation project that will fundamentally affect a number of systems, processes and resources. We believe that consideration of the existing TSO and MO licence conditions should be included. These challenges are set out in detail in this response.

Due to the complexities discussed above, EirGrid and SONI believe that a detailed cost benefit analysis should be undertaken by the Regulatory Authorities as part of any SEMC decision resulting from SEM-24-046. It is imperative that the costs incurred in designing and implementing new solutions will deliver appropriate benefits which justify the size of the costs incurred. With respect to the revised Phase 1 approach, the cost benefit analysis should consider whether the original Phase 1 approach proposed in SEM-22-036 could be applied to “short-run” DSUs only. This would result in a significantly reduced impact of the double counting of demand reduction in settlement which may be less costly than the required implementation of the revised Phase 1 solution.

EirGrid and SONI are keen to engage further on this subject in order to ensure that all initiatives requiring input from the TSOs and SEMO are considered in the context of the overall programme of works and other priority programmes currently underway so that the most beneficial initiatives can be appropriately prioritised on the basis of robust consideration of their likely cost and benefit.

EirGrid and SONI remain committed to supporting the ramp up of Demand Side Management as this is a key enabler in delivering on the Governments’ ambitions, assisting in energy affordability and security while supporting Ireland and Northern Ireland’s competitiveness. We see the role of DSUs as a large part of the Demand Side Management contribution. We look forward to engaging further with the RAs on the development and implementation of any market design or operational changes resulting from this consultation.

2 Introduction

2.1 EirGrid Plc and SONI Ltd

EirGrid plc (EirGrid) is the licenced electricity Transmission System Operator (TSO) in Ireland, and SONI Ltd (SONI) is the licensed TSO in Northern Ireland. Both companies also hold Market Operator (MO) licences in Ireland and Northern Ireland respectively and collectively act as the Single Electricity Market Operator (SEMO), which operates the Single Electricity Market (SEM) on the island of Ireland.

2.2 Structure of Our Response

This response is comprised of the following sections:

- **High Level Principles** – this sets out EirGrid and SONI's views with respect to the proposed changes and how Demand Side Units are treated in the market as well as the broader regulatory landscape;
- **Response to Consultation Questions** – In reviewing the consultation questions, we have considered the common themes across a number of questions and have grouped them accordingly. We have outlined at the beginning of each section the relevant consultation questions each section applies to.

3 Comments on the Consultation

3.1 High Level Principles

EirGrid and SONI welcome the further consultation in respect to treatment of Demand Side Units in the SEM with respect to the proposed solutions for energy payments and other issues. We have responded on previous consultations with respect to the issues with Demand Side Units and continue to consider the major issues at hand. It is important when considering the proposals under discussion to focus on the specific issue that they are seeking to solve, which is described in the consultation as being that "the current SEM ... may create incentives for DSUs to minimise rather than maximise availability at time when demand response could be of most value to the system". We feel that it is still important to highlight the complexity of the solutions being proposed for the enduring solution, both Phase 1 but especially Phase 2. As we noted in our previous responses, the Phase 2 approach is significantly dependent on data systems and transfers that do not exist within the current wholesale market design and these will involve significant time and investment to deliver. Particularly, if the Model 3 approach is preferred over Model 2 as described, the scale of the changes will result in a multi-year, cross industry implementation project that will fundamentally affect a number of systems, processes and resources.

With respect to the matters included in the consultation paper, we make the following high-level comments before addressing the consultation questions in the following section.

3.1.1 Energy Payments for Demand Response

The consultation paper outlines four models for DSUs which are stepping stones in developing the logic for a revised Phase 1 solution. Broadly, the models can be summarised as follows –

- Model 1 – current SEM approach;
- Model 2 – outlines the approach proposed as Phase 2 in SEM-22-036;
- Model 3 – outlines a variant approach to Phase 2 with limited changes in retail arrangements and all changes implemented through the wholesale market; and
- Model 4 – outlines a revised Phase 1 solution taking elements of the Model 3 approach.

Focusing on the Revised Phase 1 Solution, it is described as follows:

- DSUs receive energy payments (CIMB). This is funded by Imperfections.
- DSUs pay compensation to all suppliers ("Supplier Compensation Payment") via the Imperfections fund.
- The net cost to the Imperfections fund is the cost of wholesale energy payments to the DSU minus the Supplier Compensation paid back to the fund by the DSU.
- The price (PCOMP) associated with the Supplier Compensation Payment should be reasonable so as not to disincentivise DSUs but also not be a burden on end consumers.

The paper states that "long-run" DSUs should not expect to receive additional revenue (from the Revised Phase 1 Solution)". It is assumed that "long-run" DSUs will largely be cost neutral to the imperfections budget. However, we feel it is important to state that this may not materialise and excluding them from this model may be a more appropriate approach. However, we recognise that this will involve decisions on how to explicitly identify "long-run" DSUs and how to define them within the T&SC and Grid Codes.

We recognise the benefits of the Revised Phase 1 Solution but want to highlight that implementing this solution requires additional design and implementation work, in addition to a change request to the settlement system. There are currently multiple other priorities for the bi-annual releases, meaning the timeline for implementing this solution could be lengthy. We also want to raise a concern that introducing the concept of a supplier compensation payment has the potential to commit to Model 3 as the enduring Phase 2 solution which as we have noted above and in previous responses represents a significant expansion of the TSOs' and/or SEMO's role and their capabilities. This would not be a change to current systems but a whole new procurement of metering systems capable of interrogating retail MPRNs which will be an immense implementation project also including significant changes to market rules, codes and licences.

3.1.2 Long-run DSUs

At present, there are a small proportion of DSUs operating as "long-run" DSUs. Rather than by foregoing consumption, they achieve demand response through on-site generation (24/7). We do not feel these DSUs should be treated in the same manner or receive the same compensation as normal DSUs as they do not offer demand reduction benefits in the original manner as envisaged in the market design.

EirGrid and SONI believe there is a need to segment different forms of demand side response, and in particular, to investigate if on-site generation could be handled through the AGU model, rather than maintaining the current one-size-fits-all approach under the DSU model; however, this approach has numerous challenges. AGUs have more stringent requirements than DSUs for example, such as:

- there is a need for settlement quality metering,
- there is a need to address gaps in licencing (in Ireland).

EirGrid and SONI are also developing a new unit classification called the Dispatchable Consumption Unit (DCU) which will facilitate participation in the balancing market. This will allow sites which have the capability to switch consumption from on-site generation to electricity imported from the grid, based on price arbitrage between fuel costs and the imbalance price. This design is currently under development as part of the Strategic Markets Programme and once available may also be a more appropriate participation model than the "long-run" DSU.

It is important when considering the solution for this issue that it is done in the context of emerging technologies and developments to ensure there are no unintended consequences, for example that any decision does not have the potential for unintended impacts for Large Energy Users with on-site generation seeking to participate in the SEM.

3.1.3 Metering

Currently, demand reduction is not measured under the Trading and Settlement Code and, instead, any demand reduction which is dispatched is deemed to be delivered. Metered Quantity (QM) for DSUs is set to Dispatch Quantity (QD) for settlement purposes.

The consultation paper explores other options for DSU metering as follows:

- **Sub-metering** i.e. installing settlement quality metering on all IDSs under a DSU. Challenges include the cost, timeline and even practicality of (retrospective) implementation. This is considered a highly costly multi-year project. (Cost on customer, ESBN / NIEN for installation, maintenance, etc.)

- **Baselining**: once a DSU is dispatched, the consumption in the periods following an instruction needs to be compared to a "baseline" level of consumption to calculate the demand reduction, net of inherent fluctuation. The methodology for this would need to be defined in T&SC or Grid Code as it is not published at present. It is also unclear if the TSOs/MDPs would be responsible for this. Again, this would be a significant implementation and will need to align with the processes that we will have to introduce to implement the requirements of the Demand Response Network Code, that cannot be defined until after it is finalised.
- **SCADA** data is suggested as a more realistic interim solution. We support proposals to move away from the current arrangement where QM is set to QD, to an approach that is more reflective of the output of the DSU. This will enable DSUs to demonstrate their capability to deliver; and where they cannot, they would face the same charges as other units and are thereby fully balance responsible. Worth noting is that SCADA data is already used for settlement of DS3; however, we also wanted to highlight potential issues with this approach as follows -
    - This data is provided by the DSU operator. While as part of performance monitoring the TSOs carry out checks on this data, they cannot verify its accuracy.
    - A number of changes need to be made including modification of the T&SC, change request to internal systems and change request to market settlement systems to take in this new data and end the treatment of QM = QD.
    - Traditionally, SCADA data has not been considered revenue class metering and not suitable for use in market settlement. Specific considerations in Grid Codes and Meter Codes may need to be addressed.

3.2 Response to questions

In reviewing the consultation questions, EirGrid and SONI have considered the common themes across a number of questions and have grouped them accordingly. The following sections provide our responses across these groups.

3.2.1 Energy payments for Demand Response

Energy payments, PCOMP, Imperfections - Group questions 1, 3, 4, 5, 6, 7, 15

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

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.

The consultation paper outlines four models for DSUs which are stepping stones in developing the logic for a revised Phase 1 solution. EirGrid and SONI agree with the description of each model but note that not all models may be suitable proposals for the SEM as they would require significant work to implement and have many challenges associated with them.

The four models outlined are:

- Model 1: No DSU Energy Payments
- Model 2: DSU Energy Payments
- Model 3: DSU Energy Payments with Supplier Compensation
- Revised Phase 1 Solution

Model 1: No DSU Energy Payments. This is the model that was implemented in the SEM at Go-Live in 2018. In this model, DSUs receive CIMB payments, but the DSU is also required to register a 'Trading Site Supplier Unit' (TSSU) that receives equal and opposite CIMB charges.

Model 2: DSU Energy Payments. This is the model proposed as the Phase 2 solution in the SEMC's previous consultation. In this model, the DSU receives CIMB payments, plus any additional T&SC revenues, fulfilling the "energy payments at all times". However, in this model, it is funded by the supplier buying the "non-consumed" energy which is in turn billed to the Individual Demand Site. The challenge with this model is identifying the relevant supplier for each DSU. 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. In fact, SEMO has no visibility of any aspect of an IDS under the current market design. Implementation of this model requires clarity on the roles and responsibilities of which entity would be responsible for administering system changes to ensure "non-consumed" energy is properly accounted for. This model could require registration of individual IDSs in the wholesale market and would require changes to the T&SC to create mapping links between DSUs and IDSs between MO and TSO systems; however, IDSs are not an entity in the T&SC or the SEM Central Market Systems. Alternatively, as noted in the consultation paper, this 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.

Model 3: DSU Energy Payments with Supplier Compensation. This is outlined as being similar to Model 2 but without requiring the suppliers to bill the IDSs. The DSU receives CIMB payments, plus any additional T&SC revenues, but the DSU then compensates the supplier for the "non-consumed" energy at a "supplier compensation price", PCOMP. Again, the challenge with this model is identifying the relevant supplier for each DSU and also that this approach would seem to avoid retail changes that Model 2 could entail. This would result in adding significant complexity to the current balancing market settlement design and place further obligations on demand sites that wish to participate in DSUs relating to wholesale market registration and participation.

Revised Phase 1 Solution. In the absence of a solution for identifying the relevant suppliers to compensate as per model 3, the Revised Phase 1 Solution sets out an alternative. The DSU receives CIMB payments, plus any additional T&SC revenues. The DSU still makes supplier compensation payments, but pays them to the Imperfections Charge fund, instead of to the particular supplier, as all suppliers are financially impacted by demand reductions by means of paying for DSU energy payments via the Imperfections Charge.

This solution is aligned with approaches in other electricity markets and with EU requirements whereby "demand response shall participate on equal footing in the market". This solution means DSUs would be participating in an efficient way, similar to other resource types where they need to consider the market prices against the cost of their "primary energy source".

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.

EirGrid and SONI would like to highlight some risks associated with this approach, however. Additional design and implementation work would be required to develop and subsequently implement a modification for this solution. The supplier compensation payment requires a new charge component in the market settlement system and the T&SC. A change request to the settlement system would be required to implement this which would be progressed via bi-annual releases to the market settlement system. 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.

The implementation of the revised Phase 1 Solution is not trivial. Careful 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, such as:

- Where the PIMB is greater than the PCOMP
- Where the PIMB is less than the PCOMP
- Positive PIMB
- Negative PIMB
- Positive PCOMP
- Negative PCOMP
- Positive quantities
- Negative quantities

Consideration also needs to be given to whether this solution is appropriate for "long-run" DSUs or whether they should be excluded.

We wish to highlight that further consideration is required for the following aspects of DSU settlement when introducing changes:

1. It is uncertain how exactly the TSSU is to be treated in the proposed models. The need for TSSU is currently defined in T&SC B.9.5.4. As part of assessing the implementation of MOD_02_23, the following impacts on market systems and T&SC were identified. It is unclear if these steps would be required under the new models:
    a. **Removal of TSSU and replacing it with ASU** – this would require registration changes for all DSUs registered in the market, modifications to the T&SC and changes to market systems.
    b. **Removal of TSSU specific treatment $QMLF_{TSSU} = -DQ_{DSU}$ as currently outlined in T&SC F.2.5.6** – this option would require both changes in the market systems and modifications to the T&SC algebra to ensure no inadvertent consequences.
2. The future treatment of DSU Energy Adjustment Payment or Charge (CEADSU) introduced by MOD_17_19 is not discussed in the proposal. These charge components are applicable to TSSUs and the current interim solution algebra is part of T&SC part H.14 'INTERIM RULES TO APPLY FOR A FIXED PERIOD OF TIME FOR DEMAND SIDE UNIT SETTLEMENT'. How these charge components are addressed will need to be included as part of any new solution.

As part of our approach to determining the most appropriate model, we reviewed the analysis previously provided for MOD_02_23 for the most recent 12-month period available, i.e. September 2023 – August 2024. As part of this analysis, it was found that there is a large reduction in the payments that would be paid to DSUs under the original proposal for Phase 1 largely dependent on the lower PIMB during the sampled period (an average of €102.62 in the most recent 12-month period vs €217.05 in the previously sampled 12-month period).

The materiality for the latest 12-month period from September 2023 – August 2024 is 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.

Month	Long-run	Short-run	Grand Total	Long-run %	Short-run %
2023 - 9	2,365,639	215	2,365,854	99.99%	0.01%
2023 - 10	2,408,489	48,791	2,457,280	98.01%	1.99%
2023 - 11	2,113,096	315,600	2,428,696	87.01%	12.99%
2023 - 12	1,003,695	11,441	1,015,136	98.87%	1.13%
2024 - 1	1,608,381	288,511	1,896,892	84.79%	15.21%
2024 - 2	1,524,321	107,359	1,631,680	93.42%	6.58%
2024 - 3	1,769,170	143,996	1,913,166	92.47%	7.53%
2024 - 4	1,778,701	144,692	1,923,393	92.48%	7.52%
2024 - 5	2,373,482	88,323	2,461,805	96.41%	3.59%
2024 - 6	2,354,643	112,904	2,467,548	95.42%	4.58%
2024 - 7	2,504,383	118,063	2,622,445	95.50%	4.50%
2024 - 8	1,942,786	129,055	2,071,841	93.77%	6.23%
Grand Total	**€23,746,786**	**€1,508,950**	**€25,255,737**	**94.03%**	**5.97%**

The previous analysis covered the 12-month period from May 2022 – April 2023 and would have resulted in a payout of €55.5M, with €51.2M or 92.27% going to "long-run" DSUs and €4.3M or 7.73% going to "short-run" DSUs.

Month	Long-run	Short-run	Grand Total	Long-run %	Short-run %
2022 - 5	3,643,266	143,658	3,786,925	96.21%	3.79%
2022 - 6	4,015,201	252,842	4,268,043	94.08%	5.92%
2022 - 7	5,356,136	837,147	6,193,283	86.48%	13.52%
2022 - 8	9,103,685	1,116,274	10,219,959	89.08%	10.92%
2022 - 9	6,407,988	25,234	6,433,222	99.61%	0.39%
2022 - 10	2,928,368	106,711	3,035,079	96.48%	3.52%
2022 - 11	3,069,860	269,482	3,339,342	91.93%	8.07%
2022 - 12	5,039,909	1,098,053	6,137,962	82.11%	17.89%
2023 - 1	2,871,387	2,181	2,873,568	99.92%	0.08%
2023 - 2	2,911,741	325,430	3,237,171	89.95%	10.05%
2023 - 3	3,290,622	109,468	3,400,090	96.78%	3.22%
2023 - 4	2,629,526	8,148	2,637,673	99.69%	0.31%
Grand Total	**€51,267,688**	**€4,294,630**	**€55,562,318**	**92.27%**	**7.73%**

Despite the large difference in the two impact assessments (due to the variation in PIMB), the proportion of the payments that would go to "long-run" DSUs remains very similar, i.e. > 90% going to a small minority of DSUs.

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. This should consider whether the original Phase 1 approach proposed in SEM-22-036 could be applied to "short-run" DSUs only. This would result in a significantly reduced impact of the double counting of demand reduction in settlement which may be less costly than the required implementation of the revised Phase 1 solution.

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 any undue disadvantage or undue advantage, compared to generators? Please explain your view.

While we acknowledge the supplier compensation payment proposal as an appropriate mechanism for addressing the double counting of demand reduction, EirGrid and SONI are of the view that there are a number of challenges associated with revised Phase 1 proposal. Without the Supplier Compensation payment, there would be significant and unsustainable costs to the scale of imperfections. We agree 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. The methodology of setting the Supplier Compensation Price is a vital element to determine if equal footing exists and in determining any disadvantage or advantage compared to a different technology type.

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.

EirGrid and SONI have no specific view on how the Supplier Compensation Price should be calculated; however, we believe it is important to acknowledge some key principles in determining the solution. 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. This would allow the SEM RAs revise the calculation in the event that there is a larger than expected adverse impact on the imperfections fund. The calculation should also be carefully measured so as to not disincentivise participation by IDSs within DSUs while also protecting end consumers from excess costs. Due consideration is required for Supplier Compensation Price as value too low could drive up imperfection cost or vice versa. A method of achieving the desired outcome, would be critical when determining the methodology.

While we have noted elsewhere that it may be considered that "long-run" DSUs could be explicitly excluded from the revised Phase 1 approach, a further option would be to consider having the capability for different values of Supplier Compensation Price for "long-run" and for "short-run" DSUs.

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.

It is difficult to accurately quantify until clarification is provided and modelling on DSU expected behaviour and operational changes are defined. DSUs provide important demand reduction and this new measure has the potential to incentivise wider participation but we would like to highlight a risk of the opposite occurring and therefore additional engagement required.

We would like to highlight 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.

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.

EirGrid and SONI are 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. The RAs considered this as an Alternative Consideration in its previous consultation on this matter, SEM-19-013. While it was noted at the time that changes may be needed to Supplier Licences and there may be significant changes to systems of impacted participants, this should be considered in the context of the current proposals. We remain of the view that the Phase 2 solution will entail a significant implementation project for whichever entity is tasked with managing adjustments for "non-consumed" energy, the cost of which will be borne by all participants and consumers while the potential benefits will be realised by a subset of this.

Q15: What are your views regarding 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.

As noted in responses to other questions, we believe that "long-run" DSUs being dispatched down from a positive FPN position does not constitute "negative demand response" (being turn-up of demand above baseline), but rather that it is a reduction of demand turn-down returning demand to baseline. 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. In terms of the application of the proposed supplier compensation arrangements to the "long-run" DSU model, where such dispatch down represents a reduction in demand response, which then leads to a reduction in the amount of the compensation that DSU needs to pay, this would appear to work as intended but further modelling is recommended.

Negative demand response is valuable where it represents purchasing additional power above baseline level similar to how suppliers purchase power but in an active way with the potential for the TSO to dispatch that power on or off when it has turned on. In this way, negative demand response in the wholesale markets, through a market unit model where they make themselves available to be dispatched to increase power from 0MW into the negative output range, should be considered differently to DSUs and therefore differently to the DSU settlement approach. The unit would be purchasing the power itself in the energy markets rather than the power being purchased by a supplier. If the only place where this demand is metered and settled is on this wholesale market unit, there would be no need for a compensation approach similar to DSUs.

There may be a need to consider some more complex scenarios if this additional consumption above baseline would also appear on a supplier unit's metered consumption, where the need to consider double counting may also arise. If this model of negative demand response is considered differently to DSUs, it may be possible to set requirements which would prevent such complex scenarios from arising.

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. We support the development of this model and work in this regard is currently being progressed under EirGrid and SONI's Strategic Markets Programme.

There are also a number of existing and intended projects which have similar characteristics, and the planned treatment for hydrogen electrolysers in Northern Ireland as set out in the UK Low Carbon Hydrogen Standard. Valuable insights can be gained and lessons learned for the future development of negative demand response, in particular through the Dispatchable Consumption model in the wholesale electricity market.

3.2.2 Capacity

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.

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. In this way, Capacity Auctions can continue to deliver the appropriate balance of capacity based on its contribution to system reliability and its associated cost.

The System Operators continue to support the explicit representation of DSUs in the Capacity Market and the eligibility of Demand Side Units to receive explicit Capacity Payments commensurate with the Demand Side Unit's contribution to overall reliability. In a manner similar to how a Participant who invests in physical generation, a DSU operator is investing in the capital infrastructure (and other costs such as customer acquisition costs) to enable a reduction of electricity demand, which is analogous to generation of electricity to meet demand. As these two resources' contribution to reliability can be determined using the de-rating process, they can compete on a level playing field on the basis of their costs, which results in a portfolio that can achieve the reliability standard at least cost to the consumer.

The Capacity Market currently seeks to secure the amount of capacity necessary to meet the reliability standard on an annual basis through Capacity Auctions. The total cost of all Awarded Capacity is paid out per year. In turn, these Capacity Payments are funded by Capacity Charges, which are currently levied on day-time demand.

Demand that reduces voluntarily based on price signals and not as result of a dispatch of Demand Side Units should not have to pay Capacity Charges as it is mitigating the risk of high prices itself rather than relying on capacity providers to protect it. It follows that only demand that relies on capacity that is in receipt of Capacity Payments should be subject to Capacity Charges. A consideration here for energy payments for Model 2 is that where the supplier is required to pay for the demand reduction in addition to the Metered Demand, i.e. the non-consumed energy, it should also benefit from Difference Payments in respect of this demand reduction which will be funded by the DSUs Difference Charges in a similar manner to how demand met by conventional generation is treated.

The System Operators would argue that a charging base that takes account of non-consumed energy would be appropriate.

To implement model 3, the Supplier Unit could pay charges based on metered demand adjusted for non-consumed energy and the DSU would pay the relevant suppliers based on the site level reductions associated with DSUs that are associated with each Supplier. In this model, it would be important to ensure that the Supplier benefits from the same protections against high prices by way of Difference Payments.

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. Adopting a physical balanced approach i.e. where the quantities in are balanced by quantities out, while not always possible reduces the risk of unintended wealth transfers or impacts on incentives for efficient operation and investment.

3.2.3 Long-run DSUs

Group questions 2, 8, 13

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

EirGrid and SONI generally agree with the idea of segmenting different modes and characteristics for demand side response in order to better represent them in many different ways, in system operations or in settlement, etc. This could conceptually be related to "long-run" versus "short-run" but could also consider sites where the demand response is provided by generation versus those where it is based on process shutdown. There may be other characteristics which could be used to make such categorisation easier. In general, we believe it would be more appropriate to have categorisation done in advance, e.g. at registration stage, based on general characteristics and expected or intended operating approaches, rather than retrospective based on a look back of trading or operational behaviour. While this segmentation is considering the operating approach ("long-run" vs "short-run"), it can also be considered alongside potential segmentation appropriate to the technology approach and points raised in the consultation about the potential suitability to consider on-site generation differently, such as through the AGU model or other models which would incorporate the characteristics of generators more accurately.

Within this, a number of points would benefit from further clarity.

The consultation paper states that "long-run DSUs should not expect to receive additional revenue, which is appropriate given that these DSUs do not have a missing money problem, and their costs are fully compensated in the savings in supplier's charges." It is not clear if by this it is meant that there would be a different solution for "long-run" DSUs, or 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. If the latter, 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.

There also appears to be a point made suggesting that the "long-run" DSU model is seen as a way of declaring dispatchable demand, which we do not believe is accurate. Positive FPNs for DSUs represent if a site is utilising something to reduce demand or meet demand on-site, and so dispatching down from this FPN would represent a reduction of demand turn-down where the demand is returning to baseline. While this would appear as an increase in the amount of power that site is consuming from the grid, it would not be an increase in demand turn-up where demand is increasing from baseline. If there was an intent to represent baseline demand consumption at a positive FPN, this would cause imbalances on the system. The Dispatchable Consumption model currently under development will enable this model of representing dispatchable demand to be fully realised.

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.

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. Rather than completing analysis to make this distinction, we believe 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. In particular, we do not feel a regular test would be practical or appropriate to determine the DSU categorisation due to ongoing monitoring required and potential manipulation of data. Ideally the categorisation would be made once and could be changed thereafter only through a request from the DSU and approval from the TSOs, similar to other registration changes.

Although Commercial Offer Data is a useful tool in identifying “long-run” DSUs, we do not feel it is appropriate to use this on an ongoing basis to determine the DSU classification. Given that COD is submitted and can be revised up to Gate Closure, we don’t believe they can be easily used to identify categorisation. While TOD is not as subject to dynamic change (as TOD sets need to be tested and approved by the TSO), it is likely more reliable.

Another point of note is that changing the category from “long-run” to “short-run” or vice versa would lead to complexities in resettlement, especially if this is done manually rather than through a timestamped flag in the Revised Phase 1 solution or registration data.

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.

It may be appropriate to consider developing different arrangements for different models of demand side response which have different characteristics, for example in how they operate and their underlying cost structure. Segmentation of different approaches to demand side response into different groupings which have shared characteristics may be a more suitable way to ensure that participants can most accurately reflect their full capabilities, and therefore ensure that their participation can best align with how they can meet power system needs. It could be explored if such segmentation could be done in a more informal way, such as through incentives, or if a more explicitly formal approach such as changes to codes, licences or creation of new kinds of products could be more effective.

There can be very large differences between those DSUs which are based on turning down on-site energy consumption and those which are based on turning up on-site generation, and between those which operate as “long-run” or “short-run”. For those that have on-site generation, it would be useful to consider characteristics such as emissions levels or any operational considerations arising from emissions limits, and other constraints which are not currently reflected in the technical data provided. This information is less relevant to other models of demand side response and could be useful in helping to encourage the development of lower carbon DSUs. Since generation can be explicitly and individually metered, this could be used to help with the methodology of calculating the actual amount of response achieved, which is not possible where the response is from turning down on-site consumption without a baselining solution.

There may also be an important distinction between the different models when interpreting the intent of European and local policies around promoting demand side response. While there are requirements to be technology neutral, demand side response seems to be considered primarily in terms of changing on-site consumption in such policies, with changes in on-site generation seeming to be considered as distributed energy resources / distributed generation.

In this light, there is an argument that on-site generation should be treated more explicitly as a form of aggregated generation, with a different set of arrangements in terms of model structure and requirements.

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. While there are several features of AGUs which may not suit IDSs currently operating under the DSU model, these can be addressed through appropriate rule and licence changes; however, there would be a need for compliance with the requirements of the relevant Meter Codes. The Dispatchable Consumption model, currently under development, may also be a more appropriate model for these types of assets.

From a settlement perspective, AGUs are treated in the same manner as conventional Generator Units and are eligible for the same Balancing Market payments / charges. Should Demand Side Units wish to be treated equally, the AGU model is an option worth considering.

As AGUs are required to have settlement quality metering, this would enable them to demonstrate their capability to deliver and, where they cannot, they would face the same charges as other units and be fully balance responsible.

The main differences in their settlement would be as follows:

- Imbalance Payment or Charge would be based on actual metering; if the unit does not deliver, they will not be paid for the energy as they are currently where it is assumed any dispatch instruction received has been fully met.
- Uninstructed Imbalance charges. If a unit does not deliver what is instructed, they will also face Uninstructed Imbalance charges.
- No-Load Cost / Recoverable No-Load Costs are applicable to AGUs but not DSUs. No-Load Cost is a payment and Recoverable No-Load Cost is a charge which both feed into the Fixed Costs Payments or Charges calculation.

In summary, AGUs are exposed to more payments, but also more charges in line with conventional Generator Units.

3.2.4 Metering, baselining, SCADA

Group questions 10,11,12

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.

Some form of baselining is required to move beyond setting the metered quantity (QM) equal to the dispatch quantity (QD) for Settlement. The objective of this would be to differentiate between the inherent fluctuation of demand and the action taken by a given customer/IDS or aggregator to reduce demand either by increasing generation and/or reducing consumption. However, which party is required to implement that baselining depends on the data source to be used for the metered quantity.

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 (whether on the basis of real data or an established demand profile, which the Planning Code obliges participants to provide) to consumption following a dispatch, as they will otherwise be in receipt of "raw" meter data only and thus only able to provide "gross" consumption not the "net" change. Note that an appropriately granular sub-metering arrangement could capture this without a baselining calculation - but only where demand and/or generation were switched entirely ON or OFF which may not reflect operational reality for many IDSs.

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. That is, the aggregator will transmit a signal which captures the reduction in demand (however this is achieved and however this is measured and/or implemented in controller logic, currently the TSO has no visibility of this, although performance monitoring is carried out after the fact).

Finally, 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. When increased dispatch results in fewer cases of “raw” meter data without demand response, this will pose a challenge for developing solutions for profiling the baseline from which demand response might be measured.

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

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. Fully redundant revenue metering installations (that is, multiple communication channels serving independent main and check meters fed from separate voltage and current transformer instrument cores of 0.2S, or 0.5S accuracy class, depending on the capacity of a given generator) would be costly to design, procure, install, commission and maintain, perhaps prohibitively so. Even if the expense could be offset against income over a reasonable period, the timeline to solution delivery could be of the order of months or even years. It is not even guaranteed that space considerations or physical arrangement of generation or process equipment would permit sub-metering behind the connection point. If incoming Network Codes permit "sub-metering" at the level of individual IDS but do not enforce sub-metering of individual demand processes or on-site generation, then the issues highlighted could be considered to be mitigated to some extent.

In Ireland EirGrid is the Meter Operator for TSO Generator connections in Ireland, while ESBN perform this role for DSO Generator and Demand Connections. Also, ESBN is the Meter Operator for TSO (Transmission System Operator) connected Demand sites. In Northern Ireland NIEN is the Meter Operator for all generation and demand connections – SONI is the Meter Data Provider for certain classes of generation with a Maximum Export Capacity in excess of 5MW, and for all generators in others. It would thus 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. 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. The requirement for CT/VT Revenue class metering and instrumentation along with telecoms routes and backup power supplies, Meter Operator SLA's, the cost/time, and possible infrastructure works of this could severely restrict IDS's from registering as a DSU.

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. This task becomes more difficult and results more difficult to discern where a given IDS is complex either in terms of the inherent fluctuation of demand or the means of demand reduction, or where a given DSU operator aggregates a large number of IDSs in a portfolio comprising many different means of demand reduction.

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

SCADA which reflects the actual demand reduction delivered by a participant would be an improvement, as under current arrangements QM is simply set equal to QD for settlement. Instead of assuming that what is dispatched is delivered for the purposes of settlement, a measured value would be used. It is important to note, however, that in the case of aggregations of IDSs, in contrast to, for example, a windfarm or synchronous generator, the SCADA signal that might be used for settlement does not come from the network asset owner's instrumentation at the connection point via the substation controller and RTU, but rather from the aggregator's own control system, because the resources effecting the demand reduction are behind the connection points of the IDSs and thus not observable to the system operator and/or MDP. The aggregator responding to dispatches by controlling flexible demand and/or generation at the IDSs in their portfolio would be required to have visibility of real time consumption across all IDSs and to transmit to the TSO a signal capturing the change in this consumption. Participants providing this SCADA signal would be responsible for its accuracy. Though amenable to performance monitoring, the details of which are the TSO's prerogative to stipulate, this arrangement is not transparent. Further, there is currently no published methodology for baselining meaning different participants may implement subtly different solutions.

SCADA measurements are fundamentally intended for use in control and real time monitoring, and perhaps e.g. trend reporting or other analysis; it would be for the participant to implement an arrangement that would ensure sufficient accuracy for settlement, including imbalance charges, were use of SCADA to be extended to this purpose.

We also note that SCADA data is used in the settlement of DS3 services payments already. However, it will not be a trivial change to utilise SCADA data as the ultimate source for QM in the market settlement system. System changes would need to be made both to the TSOs' metering and other supporting systems to map the data to the market settlement system and also to the market settlement system to accept this data and end the current treatment of QD as a proxy for QM. This would also involve T&SC and Grid Code modifications to reflect the same.

We have taken this opportunity to carry out some analysis of SCADA metering against the QD that is used in settlement. For this analysis, we have used 30/04/2024, a day where multiple "short-run" DSUs were dispatched. During the period that DSUs were dispatched, "short-run" DSUs achieved 86% of the QD while "long-run" DSUs achieved 97% of the QD used in settlement.

DSU categorisation	SCADA (MWh)	QD (MWh)	SCADA vs QD (MWh)	% of QD delivered
Short-run	339	395	-56	86%
Long-run	157	162	-5	97%
Grand Total	**495**	**557**	**-61**	**89%**

3.2.5 Bidding

Group questions 16, 17

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

EirGrid and SONI do not offer advice on how to structure cost reflective bids. We believe it is the Regulators that should give guidance on how these costs are allocated and outline a methodology for cost reflective bidding. However, we do welcome the opportunity to share some of the issues we see in bidding of the DSUs relating to IDS shut down cost. 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.

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.

EirGrid and SONI do not offer advice on how to structure cost reflective bids. We believe it is the Regulators that should give guidance on how these costs are allocated and outline a methodology for cost reflective bidding. However, we 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. We would welcome greater accuracy and transparency with clearer guidance on how this should be calculated.

3.2.6 Availability declarations

Group questions 18, 19

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

The definition of Demand Side in both the SONI and EirGrid Grid Codes do require each Demand Side Unit to have a Demand Side Unit MW Capacity of 4 MW and to be subject to Central Dispatch. However, there is no requirement under either the SONI or EirGrid Grid Codes for DSUs to declare an availability of 4 MW or above.

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.

SDC1.4.1.3 Whole Numbers states that "The MW figure stated in the **Availability Notice** shall be a whole number." In addition SDC1.4.3.4 Availability of Demand Side Units states that "Each Demand Side Unit Operator shall, subject to the exceptions in SDC1.4.3.5 and SDC1.4.3.5A, use reasonable endeavours to ensure that it does not at any time declare the Demand Side Unit MW Availability and the Demand Side Unit characteristics of its Demand Side Unit at levels or values different from those that the Demand Side Unit could achieve at the relevant time. The TSO can reject declarations to the extent that they do not meet these requirements."

This means 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. However, it should be noted that the same rounding of availability figures is also applicable to Generation Units, including AGUs and Controllable PPMs and Interconnectors under SDC1.4.3.2.

We support any measure that will encourage more demand side availability; however, the availability of DSUs must be predictable and reliable. The uncertainty of DSUs availability remains a challenge and a concern which has been raised with the Regulatory Authorities (RAs) on a number of previous occasions. Reviewing the most recent EirGrid and SONI Monthly Availability Reports, the 365 Day Rolling Availability of DSUs is approximately 20% of their installed capacity. Based on this, there is considerable room for improvement in the contribution of DSUs in supporting a secure power system.

With respect to other comments in the consultation paper in relation to availability declarations and the observation that other demand response may already be participating in other demand reduction programmes, EirGrid and SONI have no objection to flexible demand assets participating in other programmes at an individual site (MRPN) where these same assets are not part of a DSU which is contracted in the Capacity Market or contracted to provide DS3 System Services.

If the same sites were to be included in different mechanisms for meeting the same needs, even if they differ somewhat (such as in the processes and sets of expectations), this may not necessarily be seen as "stacking" of these mechanisms and products but rather they could be seen as "overlapping". This could potentially lead to overlapping / double payments for meeting the same system need, rather than stacking revenues for meeting multiple different system needs. Concern on having two sets of arrangements to meet potentially the same system need is not just about the potential inefficiency but also about the potential to erode availability in the wholesale markets over all periods of time where they could also be needed. This would also likely not lead to an increase in the overall level of demand flexibility and therefore not improve the measurement of meeting the CAP target, as the same capability should not be counted twice for provision towards other demand reduction programmes and the wholesale market.

3.2.7 Open ended question - Question 14

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

EirGrid and SONI have previously commented on the scale of changes being proposed as part of the enduring solution for energy payments for DSUs. 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. This should consider whether the original Phase 1 approach proposed in SEM-22-036 could be applied to "short-run" DSUs only. This would result in a significantly reduced impact of the double counting of demand reduction in settlement which may be less costly than the required implementation of the revised Phase 1 solution.

The original Phase 2 proposal was significantly dependent on data systems and transfers that do not exist within the current wholesale market design and systems and will involve significant time and investment to deliver if it is decided to implement in this manner, requiring change to the systems of the TSOs, DSOs and SEMO. 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. Either Phase 2 approach, if implemented through the T&SC, will need mapping links between DSUs, Supplier Units and IDSs between MO, TSO and DSO systems. IDSs are not an entity in the current T&SC or the SEM Central Market Systems. As such, this is not a simple modification but will entail the creation of a new entity within the Code along with roles and responsibilities that it must accept on registration. IDSs are already registered within the DSO systems and requiring market registration with the wholesale market operator, when the IDS will have no direct activity within the wholesale market arrangements places an additional burden on them. SEMO also has no governance role over IDSs currently and it would need to be investigated if there is a need for changes to the TSOs' or MO's licences to support this. We remain of the view that the Phase 2 solution will entail a significant implementation project for whichever entity is tasked with managing adjustments for "non-consumed" energy.

It must also be noted that many of the topics discussed within the consultation paper will require significant programmes to implement. This includes suggestions to use SCADA in place of settlement class metering and any base-lining solution regardless of the entity responsible for it. The scale of the changes to support the enduring solution should not be under-estimated and may result in a multi-year, cross industry implementation project that will fundamentally affect a number of systems, processes and resources. Any implementation must also align with requirements in the Demand Response Network Code, which has yet to be finalised.

Given the scale of reform aspired to over the coming years in the context of renewable targets, it is important that the SEM Committee and the RAs have sight of the likely interaction between initiatives which are competing for resources from the same pool and funding in order to plan and prioritise accordingly. We are keen to engage further on this particular subject in order to ensure that all initiatives requiring TSOs and/or SEMO input are considered in the context of the overall programme of works so that the most beneficial initiatives, in the Regulatory Authorities' view, can be appropriately prioritised on the basis of robust consideration of their likely cost and benefit and their impact in helping meet the 2030 emissions and renewable energy goals, and ensuring power system security in both the shorter and longer timeframes.

4 Conclusion

EirGrid and SONI recognise the contribution of Demand Side Units (DSUs) to the power system and their role in the transition currently underway, as well as the benefits of demand response in potentially alleviating some of the security of supply concerns facing the power system. We support any measure that will encourage more demand side availability; however, DSUs must be reliable and available when required.

EirGrid and SONI agree that there is a need to address the missing-money problem for high-cost DSUs that provide demand reduction at times of high wholesale prices. As these DSUs may be operating at a loss, we appreciate the need for incentives to maximise availability, rather than minimise availability at these times, when demand reduction is most needed.

EirGrid and SONI feel that it is important to highlight the complexity of the solutions being proposed for Phase 1 and Phase 2. While we recognize the benefits of the revised Phase 1 solution, it is also important to recognise that this is not a trivial change and will involve additional design and implementation work for which there is a cost and timeline to be considered.

Due to the complexities discussed above, EirGrid and SONI believe that a detailed cost benefit analysis with the full participation of Meter Operators and Meter Data Providers as well as the Market Operator should be undertaken by the Regulatory Authorities as part of any SEMC decision coming from SEM-24-046. It is imperative that the costs incurred in designing and implementing new solutions will deliver appropriate benefits which justify the size of the costs incurred.

EirGrid and SONI are keen to engage further on this subject in order to ensure that all initiatives requiring input from TSOs and SEMO are considered in the context of the overall programme of works so that the most beneficial initiatives can be appropriately prioritised on the basis of robust consideration of their likely cost and benefit.

EirGrid and SONI remain committed to supporting the role of DSUs as part of a reliable and affordable power system and we look forward to further engaging with the RAs on the development and implementation of any market design or operational changes resulting from this consultation.