Future Power Markets Workshop

Questions & Answers

Thank you for attending the Future Power Markets Workshop on **Tuesday, 27 January 2026.**

This document provides answers to the questions raised during the event. For ease of reference, the FAQ is organised by each segment presented on the day.

Segment
1. Scheduling & Dispatch Programme (SDP)
2. Future Arrangements for System Services (FASS)
3. Energy Market Policy (EMP)
4. Long Duration Energy Storage (LDES)
5. Technical Liaison Group (TLG)
6. Strategic Markets Programme (SMP)
7. Manually Activated Reserves Initiative (MARI)

1 Scheduling & Dispatch Programme (SDP)

Q1: The slides outline that **Scheduling and Dispatch Tranche 2** will be delivered in H2-26. Can you clarify what month this is expected?

A1: The SDP team are currently in the final stages of detailed planning and hoping to provide clarity in the February FPM Industry workshop.

Q2: How do SDP-03 and SDP-05 interact with current DS3 procurement and with FASS?

A2: The current DS3 procurement and FASS procurement deal with the payment method for the system service. SDP-03 and SDP-05 relate to the control centre capability to schedule and monitor the reserve services.

Q3: SDP-04: When is data supposed to be available regarding the impact of rebalancing?

A3: Over the past two months, the control centre has been building operational experience with the new functionality introduced by SDP_04. Regarding the impact of rebalancing, it will take time for trends to adjust following the implementation of SDP_04. We will consider providing an update after a sufficient period has passed.

Q4: Can you give any guidance on the nature of the discussions with the Regulatory Authorities (RAs) on SDP-01? Will there be an impact on the Trading and Settlement Code modification?

A4: Two constructive meetings have been held with the Regulatory Authorities during January where both parties reaffirmed shared objectives and reviewed the modelling approach. We hope to share more information at the end of February.

Q5: How will Synchronous Condensers recover their start and no-load costs if they are required to submit zero values?

A5: As synchronous condensers do not provide active power, they will not be submitting or recovering Start Up Costs or No-Load Costs in the balancing market.

Q6: Regards to non-priority dispatch clarity, is it in February or when will we get an update?

A6: The SDP team plans to share a further update at the FPM Industry workshop in February, providing more clarity on the outcome of the discussions with RAs. If needed, a standalone session will be arranged.

Q7: Have there been any operational issues since SDP go live for Battery Energy Storage System?

A7: Dependent on definition of operational issues. There have been some issues with response from participants to dispatch instructions. However, in general, the changes introduced by SDP_02 have been very positive. If any further information on operational issues is given on this question, it can be investigated further.

Q8: Will there be a mop up process for missing Dispatch Instructions for Battery Energy Storage System (BESS) units for the post go live period?

A8: The SDP team is not currently aware of issues relating to missing dispatch instructions for BESS units since SDP_02 go-live. In the weeks following SDP_02 go-live, an operational constraint was restricting control centres from dispatching BESS units to follow PN. From 19th December, the constraint has changed from a unit-level to a group-level constraint resulting in less deviation from PN. BESS units should continue to only change output on receipt of dispatch instructions from the control centre. If there is a concern around missing dispatch instructions, please raise a settlement query via info@sem-o.com.

Q9: Can you clarify what that additional funding will be used for?

A9: The initial funding received was based on Tranche 1 being completed in early 2025. The additional funding will cover the remaining costs to close out the programme based on the detailed planning that has since taken place.

Q10: How will Synchronous Condensers recover the VOM components of start and no-load costs if they are required to submit zero values?

A10: As synchronous condensers do not provide active power, they will not be submitting or recovering Start Up Costs or No-Load Costs in the balancing market.

Q11: Our experience post-SDP for BESS is that Dispatch Instructions (DIs) are still not closely aligned to Physical Notifications (PNs), despite being under 'Follow PN' - rather than tracking just overall energy or time under 'Follow PN', we would like to see some tracking and reporting on how close actual DIs are to PN, can this be considered?

A11: We are monitoring the "follow PN" approach and taking measures to ensure it is adhered to as closely as possible. Regarding reporting, we are working with the RAs to agree monitoring of the SDP_02 solution.

Q12: Can you please clarify if an SCU SS provider flag will always = 1? Or what conditions influence this flag?

A12: SDP_06 proposes no change to the existing System Services Provider Flag introduced with Mod_13_19 which is utilised by synchronous condensers as well as other System Services Providing Units. The System Services Provider Flag is set to 1 for each period where the unit is dispatched to provide a system service. When the flag is set to 1, the unit is not charged for their energy consumption.

Q13: Can EirGrid provide an update on the grandfathering of oversupply?

A13: The RAs and TSOs are currently progressing the SDP_01 initiative by undertaking independent modelling to inform decisions on Mod_13_23 and SEM-24-044. The TSOs intend to host an industry workshop to provide clarity on progress and next steps. Once decisions are made on Mod_13_23 and SEM-24-044 a period of at least 6 months will be required to finalise system designs, testing and other readiness activities.

The enduring solution for NPDR as set out in SEM-21-027 will follow in a future programme of work under the Balancing Market Reform workstream.

2 Future Arrangements for System Services (FASS)

Q1: What is the timeframe for the publication of the next iteration of the FASS PIR (Phased Implementation Roadmap)?

A1: The current target date for PIR V4.0 is March 2026. Its publication is dependent on agreement being reached with the Regulatory Authorities (RAs) on the publication of the FASS non-reserve services consultation paper; the TSOs are working intensively with the RAs to align our positions on this matter.

Q2: Is there any update on when the non-reserves publication might be?

A2: As stated above, the TSOs are working intensively with the RAs on the non-reserve services consultation. We are currently targeting March 2026 to publish the paper.

Q3: In the status update, there is a lot of red and amber [RAG]. Are the TSOs confident that the FASS programme can be delivered by the deadline for the termination of DS3 set by the SEM Committee, noting there are a number of other challenging projects ongoing?

A3: The TSOs are working toward a FASS go-live of May 2027. V4.0 of the PIR will provide greater clarity to industry on programme deliverables.

Q4: Is there any update on the DS3 scalar decision?

A4: James Carson of the Utility Regulator (UR) noted at the workshop that the RAs are targeting February 2026 for a SEMC decision on the Temporary Scarcity Scalar rates.

Q5: With DASSA and RAD PQ submissions being made at same time, how can the system decide on which awarded PQ is chosen?

A5: This topic has been raised by industry at other FASS Programme fora, including the Grid Code Working Group. The TSOs have been developing worked examples that illustrate the interaction between the bidding processes of the DASSA and RAD and will share these with industry shortly.

Q6: If a seller's order is not matched in the first hours after secondary trading has begun, can they update the price they will accept as they get closer to delivery? Can they withdraw their order from secondary trading? Same question for a buyer?

A6: Yes, if the secondary trading gate window is still open for a Trading Period (i.e. at least one hour before the Trading Period), a Seller / Buyer can amend an existing Offer and resubmit it, or withdraw the Offer, if it has not been matched in previous batches.

Q7: Why is a third party required for collateral when it is not required for secondary trading in the Capacity Market?

A7: As part of the TSOs' original proposal for secondary trading, the settlement of transactions between trading parties, i.e. the payment of the secondary trading price from Buyer to Seller (or vice versa in the case of a negative sell price), would be carried out between the parties, with neither the TSOs nor any other third party involved in the process.

The TSOs received strong feedback from industry that this arrangement would be a barrier to entry into secondary trading for many service providers: the risk to Sellers that they would not be paid in a timely manner would encourage service providers to only trade bilaterally within the same party's portfolio, with established trusted parties, or not at all.

Collateral arrangements are therefore required to enable effective secondary trading between parties, with parties confident that they will be paid following successful secondary trades. When investigating how best to implement such arrangements, the possibility of the TSOs managing this process was ruled out: the TSOs cannot fund such arrangements and take on that risk; secondary trading collateral arrangements must therefore be managed centrally by a third party.

Q8: For any period where there is scarcity and the TSO procures in the secondary market, the scarcity price applies to DASSA orders. Will the scarcity price apply to the RAD as well?

A8: The Scarcity Price will not apply to the RAD directly, but RAD offers will ultimately be capped at the Scarcity Price for the service requirement in this scenario.

Q9: How will bilateral transactions interact with bids and orders under a simple batch matching submitted in the secondary market for FASS?

A9: Bilateral trades will be treated differently to Buy and Sell Offers submitted into the secondary trading platform to be matched. The TSOs will validate that a bilateral trade does not violate auction constraints and evaluate it against the units' qualified capabilities. Once a bilateral trade has been validated successfully, the trade will be considered as 'matched' in the secondary trading Order Book. The outcome of bilateral trades will be captured with regard to a unit's DASSA Order – adjusted up or down depending on whether the Order holder is a Buyer or Seller.

Q10: Is bilateral bidding in the secondary market performed on a unit basis? If so, can units held by the same participant entity be traded internally, and would such activity be classified as a wash trade?

A10: Bilateral trading will be performed on a unit basis. A unit may trade with another unit in the same portfolio (party). Note that the SEMC states in its FASS DASSA Market Design Decision Paper SEM-24-066 (section 3.6): *[Bilateral trading] will be kept under ongoing review, and the mechanism may be ceased in the event concerns around market power abuses emerge.*

Q11: Could you provide additional information on how settlement works for secondary trades when obligations are transferred from one market participant to another?

A11: A DASSA Order, or portion thereof, that has been traded successfully in a batch, transfers to the Buyer following that batch. The Buyer now holds all the commitment obligations of that Order (or portion thereof) and will be in receipt of the DASSA Payment for that Order (or portion thereof) assuming all commitment obligations are met.

The holder of a DASSA Order, whether secured in the daily auction or subsequently in secondary trading, may submit a Sell Order within the secondary trading window.

Q12: Are DASSA payments also transferred as part of this process? Additionally, how is any arbitrage between the original DASSA order and the secondary transfer passed on to the seller of the DASSA order?

A12: Yes, the successful Buyer will be in receipt of the DASSA Payment for the Order (or portion thereof), assuming all commitment obligations associated with the Order are met.

The TSOs intend that the settlement of secondary trades between Buyers and Sellers – the payment of the secondary trading prices from Buyer to Seller – will be managed centrally (via a third party), accounting for the provision of collateral by trading parties.

Q13: Can you elaborate on the primary cause for secondary trading solution delays?

A13: The TSOs assume that this question relates to collateral arrangements for secondary trading. As these arrangements must be managed centrally by a third party (see our response to Q7 above), the TSOs have been conducting a tender process to secure the appropriate capabilities. This tender process is still ongoing.

Q14: For penalties could you include a worked example when you send around the slides?

A14: Further details on the Compensation Payment and Availability Incentive are provided in response to questions 32 and 35 below.

Q15: Will there be an availability incentive to be paid for post-gate closure TSO lapsed units? The paper only says the compensation payment will be set to zero.

A15: In our Parameters and Scalars Recommendations Paper (section 7.5.3), in recommending an Availability Performance Scalar, we noted: *Exceptions will apply where unavailable DASSA Order volumes result from TSO actions / events or for Trading Periods falling withing a Grace Period.*

It is the TSOs' position that such exceptions should also apply to the SEMC's decision to implement one-off Availability Incentives (instead of scalars). The TSOs will request the RAs to clarify the SEMC's position on this matter.

Q16: If dynamic POR is scarce (scarcity pricing is triggered) in a given period would the scarcity price apply to static POR DASSA Orders?

A16: No, in this scenario the Scarcity Price would only apply to dynamic POR (in a jurisdiction). Scarcity Pricing applies when the TSOs do not procure the required volume of a service + zone + quality combination, within a threshold, in the day ahead auction.

Q17: Will the DASSA scarcity price apply to service providers who are dispatched to provide a service that is scarce (scarcity pricing is triggered and required volume of the service is not procured at the closure of the secondary trading window) through the RAD?

A17: The RAD will pay service providers for their residual availability above other market commitments (including DASSA Orders), if they are in merit.

The TSOs consider that it would make sense to include any outstanding Volume Insufficiency, i.e. volumes not sold by the TSOs in secondary trading, in the RAD volume requirement. However, given that this is not specifically set out in the FASS DASSA Top-Up Mechanism Decision Paper SEM-25-056, nor in the TSOs' recommendations paper, we will request the RAs to clarify this with the SEMC.

As per our response to Q8, the Scarcity Price will not apply to the RAD directly, but RAD offers will ultimately be capped at the Scarcity Price for the service requirement.

Q18: In relation to Priority Dispatch Units and Implicit FPNs, what does the position that DASSA Orders for PD wind and solar units will automatically be confirmed at gate closure mean?

A18: As Priority Dispatch (PD) wind and solar units do not submit explicit Physical Notifications, the TSOs cannot check that such units' DASSA Orders are compatible with their market position at gate closure - unlike, for example, dispatchable thermal units. As such, the TSOs will assume that PD units' DASSA Orders are compatible and therefore 'confirmed'. The impact of this is that PD units will not be subject to Compensation Payments, payable to the TSOs, for lapsed DASSA Order volumes. However, the obligations to fulfil the DASSA Orders in real time will remain.

Q19: If a PD takes a DASSA Order, will it automatically be deemed to have been delivered regardless of whether the unit is available to provide the service?

A19: No, per the response to Q18, the obligations to fulfil DASSA Orders in real time remain. PD units must make themselves available to provide the DASSA Order's service volume and to deliver the service when called upon to do so. Failure to do will result in the application of Availability Incentives and Delivery Incentives, respectively.

Q20: If so, does this run counter to the commitment model of the DASSA market, and could its risk incentivise PD units to take DASSA Orders without reference to their expected availability to deliver?

A20: No, as per our responses to Q18 and Q19, the obligations of PD units to fulfil their DASSA Orders in real time remain, with incentives applying to service availability and delivery.

Q21: If so, could PD units become price takers in the DASSA auction to the level of their service capability resulting in the market being distorted and increasing the level of reliance on the RAD? What is the scale of service capability in the PD category across high and low frequency services?

A21: As per our responses to Q18, Q19 and Q20, PD units holding DASSA Orders will be subject to Availability and Delivery Incentives. The TSOs expect that PD units will manage their exposure in the DASSA through secondary trading and self-lapsing, as with other service providers.

Regarding the service capability of PD units, the TSOs are currently in the process of evaluating the non-priority dispatch renewable (NPDR) status of wind and solar units. Once this exercise is complete, the outcomes will be communicated to industry through the appropriate channels.

Q22: If a PD unit takes a DASSA Order for a low frequency service and trades to it full availability ex-ante, will it be automatically deemed to have delivered on its DASSA Order? Would the PN unit be paid as if the DASSA Order has been delivered?

A22: Our responses above refer. In this example, the unit will have its DASSA Order confirmed, i.e. it will not be subject to a Compensation Payment for lapsed volumes. However, its payment for the Order will be subject to Availability and Deliver Incentives.

Q23: If a PD unit takes a DASSA Order for a low frequency service, will it be dispatched to its full availability to provide energy by its TSO, in the absence of requirements for constraint or curtailment?

A23: For DASSA go-live in May 2027, the outcomes of the daily auction will not be a direct input to the TSOs' scheduling and dispatch processes.

Q24: If a PD unit takes a DASSA Order for a low frequency service and is dispatched to its full availability will the PD unit service volume be deemed to have become unavailable post gate closure and be subject to the Post Gate Closure Availability Incentive?

A24: In the first instance, we refer to our response to Q15 above.

A DASSA Order Holder that is not available to fulfil its obligations in real time may have the applicable Availability Incentive waived if the cause of its unavailability was due to a TSO action.

Q25: If a PD unit takes a DASSA Order for a low frequency service and is subject to constraint or curtailment, will it by expect to respond to a frequency event by increasing its generation above the level of the constraint/curtailment?

A25: It is current TSO operational policy for PD units (and non-PD units) that are curtailed / constrained to have Active Power Control and Frequency Response switched on (enabled) – and therefore capable of providing upward reserve in response to a low frequency event.

Exceptions to this policy will apply where a transmission line is at risk of being overloaded, in which case Frequency Response will be disabled.

Q26: If a non-PD unit take a DASSA Order for a low frequency service, will it be expected to submit a PN that is below its Availability at gate closure?

A26: A non-PD unit must submit a PN that is compatible with its DASSA Order, meaning that its PN at gate closure must allow sufficient headroom for the volume of the DASSA Order (upward reserve). For example, a unit with 50MW registered capacity (export) that has been awarded a DASSA Order for an upward reserve service of 10MW must submit an FPN of 40MW or less. If the unit submits an FPN greater than 40MW, it will be subject to a Compensation Payment for the amount of the incompatible (lapsed) volume.

Q27: Non-PD and PD units are equally challenged to forecast availability at the time of DASSA gate closure, what is the basis to treat them differently?

A27: A core component of the DASSA design is that a DASSA Order Holder must ensure that its Order is compatible with its market position at gate closure, i.e. one hour before the applicable Trading Period.

However, the TSOs acknowledge that not every service provider type participates in the ex-ante market in the same manner, including PN submission. As such, we have sought to accommodate service providers that do not specifically submit FPNs, such as PD units, by assuming that their DASSA Orders are compatible and therefore ‘confirmed’. As stated above in our responses, a PD unit that has a Confirmed DASSA Order will not be subject to a Compensation Payment, payable to the TSOs, for lapsed DASSA Order volumes, but will be obligated to fulfil the Order in real time.

Q28: The TSO's Recommendation Paper states in relation to PD units that "decoupling service delivery from market exposure and relying on real-time availability for validation, the framework ensures that PD units can compete on a level playing field with other technologies", however all other categories of service providers are expected to manage the interaction energy and DASSA market positions, how does this create a level playing field?

A28: In this case, “level playing field” refers to the need to ensure that all technologies can participate in the DASSA. As we stated in our Parameters and Scalars Recommendations Paper:

This reflects the TSOs' commitment to inclusive participation and ensures that the auction process accommodates the diverse operational characteristics of all service providers.

Q29: Is PD status intended to give preferential access to the DASSA market?

A29: The treatment of PD units regarding FPNs is to ensure that they can participate in the DASSA arrangements, given the mechanics of the DASSA design, and not to give preferential treatment. In this respect, the TSOs note EGBL Article 3.1(a): *This Regulation aims at fostering effective competition, non-discrimination and transparency in balancing markets*.

Q30: Does the commitment obligation compensation payment apply to PD units, if so, how would the lapsed volumes be calculated?

A30: To recap, as Priority Dispatch (PD) wind and solar units do not submit explicit Physical Notifications, the TSOs cannot check that such units' DASSA Orders are compatible with their market position at gate closure. As such, the TSOs will assume that PD units' DASSA Orders are compatible and therefore 'confirmed'. In this case, PD units will not be subject to Compensation Payments but must meet the Order's obligations in real time.

However, a PD unit may choose to **self-lapse** some or all of its DASSA Order before gate closure, should the unit consider that it does not want to be exposed to the Availability and Delivery Incentives in real time. A Compensation Payment, payable to the TSOs, will apply to the self-lapsed Order volume.

Q31: Where a service providing unit becomes unavailable due to a forced outage just before gate closure will the unit be subject the pre gate closure incentive plus the post gate closure availability incentive and in the event of a system frequency event the once off performance incentive also?

A31: Exemptions to the DASSA incentive framework will only apply where a unit is subject to TSO actions or where a unit is within a defined Grace Period for the relevant Trading Period (note that a DASSA payment would still be forfeited).

In the example above, assuming that the unit's FPN is compatible with its DASSA Order, the Compensation Payment for lapsed volumes will not apply. However, the unit will presumably declare down its availability to provide services, in which case the Availability Incentive will apply. The Delivery Incentive will only apply to DASSA Order volumes that have been declared available.

Q32: In relation to the Post Gate Closure Availability Payment the SEMC decision states "in instances of units declaring unavailability post-gate closure this incentive will apply in addition to the Compensation Payment" does this relate to the Compensation Payment being imbedded in the formula for the Post Gate Closure Availability Payment or as a separate, additional stand-alone charge.

A32: In totality, the DASSA Availability Incentive will comprise:

- Forfeit of the DASSA Payment for any Order (or portion thereof) that is not declared available in real time.

- Application of the Compensation Payment multiplier (refer SEM-25-074 section 4.12) to any Order (or portion thereof) that is not declared available in real time.
- Application of the Availability Incentive multiplier (refer SEM-25-074 section 4.13) to any Order (or portion thereof) that is not declared available in real time.

For example, if a unit holds a DASSA Order for 20 MW of Dynamic POR in NI for a specific Trading Period and declares itself unavailable for 10MW of Dynamic POR for that Trading Period:

- The unit will receive a DASSA Payment for just 10MW, with the DASSA Payment for the unavailable 10MW forfeit.

  Plus

- The unit will be subject to a Compensation Payment (payable to the TSOs) of 10MW x DASSA Clearing Price x 0.7.

  Plus

- The unit will be subject to an Availability Incentive (payable to the TSOs) of 10MW x DASSA Clearing Price x 0.25.

Q33: Can non-DASSA, non-RAD service providers if compelled to declare their service capability under Grid Code be exposed to any incentive charges under the DASSA incentive framework?

A33: This issue, and related matters such as mandatory participation in the DASSA arrangements, are actively being discussed by the RAs and TSOs. The outcome of these discussions will be communicated in due course to industry through the appropriate channels. The TSOs note that the SEMC's FASS Parameters & Scalars Decision Paper SEM-25-074 (section 4.14) states: *For units without a commitment obligation who receive a System Services payment e.g. RAD contract holders, further consultation is required to determine an appropriate incentive for these units.*

Q34: Scarcity price €650/MWh and the Secondary Trading Platform.

Please could the team explain how the Scarcity price will work, perhaps with an example. My understanding: If DASSA Orders lapse, then TSO will seek to procure MW in the Secondary Trading Platform. The TSO will be offering €650 per MWh, per service. And, do I understand that this will set the Clearing Price at €650/MWh in the Secondary Trading Platform for this Trading Period. If participants (total 200MW) needed to offload/shift their obligation and were looking for Sellers in the Secondary Trading platform, they would be hoping to sell at the same price (or a little less) than they receive for the DASSA orders. If the TSO was looking to procure 20MW in the Secondary Trading Platform, would this set the price for the remaining 180MW? If they (participants with 180MW obligation/DASSA orders to offload) then had to pay €650-/MWh to move their MW, this would leave them at a major financial loss. This could happen every day. TSO will always be 'short' a small number of MW, where one participant 'lapses' (I would think).

A34: Scarcity Pricing applies in instances of Volume Insufficiency only, i.e. where the TSOs do not procure required volume (service + zone + quality) for specific Trading Periods in the DASSA, within a threshold. Scarcity Pricing does not apply to lapsed volumes.

For example, an instance of Volume Insufficiency occurs for a volume of 20MW of Dynamic POR in NI for two Trading Periods between 12:00 – 13:00 in D. In this case:

- The DASSA Clearing Price for Dynamic POR in Northern Ireland for the period 12:00 – 13:00 in D will be set to the Scarcity Price of €650/MWh (Stg equivalent), applying to all DASSA Orders for this requirement i.e. DASSA Orders awarded in the daily auction and any Orders subsequently traded in the secondary market.
- Following the publication of the DASSA outcomes, the TSOs will enter the secondary market with a Sell Order for 20MW of Dynamic POR in NI for 12:00 – 13:00 in D.

Note: The DASSA Clearing Price is not to be confused with the secondary trading Buy and Sell prices – the prices that a Buyer and Seller are willing to pay to / receive from the other trading party to transfer a DASSA Order (or portion thereof).

Q35: Compensation Payments: Decision 12

While the calculation of the Compensation payment is quite clear and simple, there is no reference to forfeiting the DASSA clearing price. In the event that a participant Clears an Offer in DASSA and subsequently finds that the unit cannot meet the obligation, the participant would pay up to 70% of the DASSA Clearing Price as a Compensation Charge. It would appear that the participant gets to keep 30% of the DASSA Clearing Price. As the SEM Decision does not mention forfeiting the DASSA payment, it leaves this uncertain. Could we get clarity on this.

A35: A Compensation Payment will be payable to the TSOs for any lapsed volume of a DASSA Order, which may be self-lapsed volume or volume that is incompatible with a unit's FPN at gate closure (1 hour before the applicable Trading Period). The Compensation Payment rates are specified in the SEMC's FASS Parameters & Scalars Decision Paper SEM-25-074 (section 4.12).

DASSA Payments will **also** be forfeit for any lapsed Orders (or portion thereof). Per the SEMC in its FASS DASSA Market Design Decision Paper SEM-24-066 (section 4.1): *The SEM Committee has decided that all units which are unable to meet commitment obligations will not be eligible to receive a DASSA payment.*

3 Energy Market Policy (EMP)

Q1: Would be useful to get indicative timelines, what sort of timescales are being discussed.

A1: First from a policy perspective there is no set timeframe, the team are currently monitoring, on a frequent basis, publications and announcements on a government and commission level. From an implementation perspective, it is in early stages for analysis. As soon as there is further information on this it will be communicated.

Q2: Future meetings, from a wind and solar perspective, interconnection flows lead to curtailment. Would be interested in learning more about effects of flow based and advanced hybrid coupling and what difference that might make for renewable generators for both France and GB return?

A2: From a SEM-GB point of view, currently analysing at present these are options for a couple of topics including advanced hybrid coupling and flow based.

When Celtic go lives and integration with CORE, GB market will be different time frame. EirGrid and SONI fully understand the need for additional information on this topic. This information will be relayed once understanding of what will come out of this workstream and how do we integrate with capacity calculation at regional level is understood. Looking at this we do understand CORE and limitations as TSO. Information will come out over the coming months and a day in the life following Celtic go live. SEM -GB impact is more unknown.

Agreed that a dedicated deep dive session is needed and will be had in the time needed.

Q3: If the UK rejoins the IEM and other EU platforms, adopting policy changes since Brexit, does this mean we could see SEM-GB capacity market coupling similar to what is being consulted on currently between SEM and France Capacity Markets? i.e. SEM units can participate in GB CM and vice versa.

A3: I think the question is referring to the options for cross border participation of capacity in other EU member states (. i.e. France for Celtic) as per requirements of 2019 Electricity Regulation and proposed in the below linked SEMC consultation which closes on 6th of March 2026. Note these options would not apply to GB capacity as GB is not part of the IEM but as the question implies the options could apply in future depending on the arrangements that are ultimately agreed between the EU and GB.

SEM-25-071 Cross Border Consultation_v400_ For Publication.pdf

Q4: Can you give us an outline of what the alternative capacity calculation approaches may incorporate into the calculations? - Onshore transmission outages, system limitations such as SNSP, Priority Dispatch requirements?

A4: The presentation outlined three approaches to capacity calculation, Net Transfer Capacity (NTC), Flow-Based and Advanced Hybrid coupling. Capacity is calculated at the level of capacity calculation regions (CCRs) of which there are 8 in the EU. SEM joined the Core Region in 2024. If GB rejoins the IEM, the options will be for it to join an existing CCR such as Core or to establishh a separate CCR. CACM 2.0 may dictate that explicit arrangements should apply on borders with third countries and that NTC shall apply at EU-GB borders but that regions such as Core can establish 'concerned capacity regions' with third countries where flow-based could apply at the EU-GB border.

The methodology for the Core DA CCM linked below it explains exactly which inputs are taken into account for capacity calculation. Core TSOs' proposal for the 4th amendment of the Day-Ahead Flow-based Capacity Calculation Methodology - European Network of Transmission System Operators for Electricity - Citizen Space

4 Long Duration Energy Storage (LDES)

No questions were raised during this segment.

5 Technical Liaison Group (TLG)

Q1: When will it be launched and how do Market Participants contribute?

A1: Anticipate launch towards end of March/early April, will provide an update in February. Participation and points of contact will be received through surveys and normal channels.

6 Strategic Markets Programme (SMP)

Q1: What percentage of interconnection capacity will be sought to be made available to the market if you are looking for a derogation to the 70% rule?

A1: It is not decided yet if there will be a request for a derogation. We are currently looking at load flow applications to see if can supply the 70% rule, which is a result of EU regulation. There is also a question about whether GB interconnectors will be allowed to be included (based on CACM2.0).

Q2: Is consideration being given to FTR trading on Celtic and on the SEM-Betta border in the case of reintegration?

A2: The Joint Allocation Office (JAO) will offer Financial Transmission Rights (FTRS) on the Celtic Interconnector after we go live in 2018 as per the requirements of the Forwards Capacity Allocation Guideline. These requirements do not apply to arrangements on the SEM's border with a third country in this case GB. CACM 2.0 could potentially define the arrangements to apply with third countries, and this could enter into force later this year.

7 Manually Activated Reserves Initiative (MARI)

Q1: Will the flow change on Celtic as a result of MARI be limited to the 5MW/min ramp rate?

A1: The application of the ramp-rate has been built-in to the calculation of the realised net volume. The local list and MARI list are built by applying unit ramp rates first and then the Celtic ramp rate, resulting in a stack of bids with a pre applied ramp rate.

Note, the value of ramp rate which will be applied to flows on Celtic is yet to be determined

Q2: Will Priority Dispatch wind/solar variable generation decremental offers (at deemed price of zero?) be made available in the LMOL to French TSO via MARI? Will conventional Priority Dispatch biomass/hydro incremental/decremental offers be made available via MARI?

A2: In the current design, which is based around balancing service providers which can provide balancing service, this means dispatchable units, based on offers for increases (INCs) and decreases (DECs) that are actively submitted by participants.

Q3: Is the price for the energy provided through MARI valued to the participant at the SEM imbalance price or the imbalance price of the receiving TSO?

A3: The price for energy provided through MARI will be the Bid Offer Acceptance Price (PBOA) of the Interconnector Residual Capacity Unit and will feed into the calculation of the SEM imbalance price. There is the possibility that this price could be taken out during flagging and tagging, in which case it becomes the imbalance price of the receiving TSO and impacts into the SEM through dispatch balancing costs and imperfections (as happens with other TSO actions that are not included in imbalance pricing).

Q4: Does LMOL include only dispatchable generation, or does it reflect all generators' offers in the RTD (i.e. simple offers, or complex PQ offers where no simple offer is submitted, including NPDR)?

It would also be helpful to have a table mapping the different generation types and offer formats (simple, complex, TSC deemed/required) to their treatment in LMOL.

A4: The LMOL is created after BM gate closure where generally only simple bids are applied. The design with respect to the LMOL is therefore focused only on simple, which is populated with complex incs/decs where no simple offer is submitted based on current SEM rules. Details of the make-up of the merit order list will be included in the **Methodology for the Integration of the Single Electricity Market with Manually Activated Reserves Initiative Platform** which is currently being drafted by the TSOs and SEMO and will be shared with industry ahead of consultation later this year.

Q5: In relation to MARI if it becomes price effecting, participants will be directly impacted and therefore transparency on the TSO decision making relating to MAIRI will be very important.

A5: This is noted. There are many requirements around transparency and publication on the TSOs with respect to interactions with MARI, including data on submissions and results, along with reporting on deviations. These requirements are included in the design that the TSOs and SEMO are developing for the integration of the SEM with MARI.