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Energy Storage Ireland Response to the Shaping our Electricity Future Consultation

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Introduction

Energy Storage Ireland (ESI) is a representative body for those interested and active in the development of energy storage in Ireland and Northern Ireland.

We work together to promote the benefits of energy storage to decarbonising Ireland's energy system and engage with policy makers to support and facilitate the development of energy storage on the island.

Energy storage will play an essential role in facilitating the higher levels of renewable generation on the power system required to achieve national renewable electricity targets. The flexibility of storage systems and their ability to contribute to the energy, capacity and system services markets allows them to deliver a wide range of benefits to end consumers such as wholesale energy price reductions, reduced CO_2 emissions and flexible system support services to help manage the grid with higher levels of renewables.

A robust policy, regulatory and commercial framework is needed to allow for the deployment of energy storage on a large-scale. Baringa's 70by30 report[1] projects at least 1700 MW of energy storage will be needed by 2030 and that these projects will be active across a number of markets such as system services, capacity and energy trading. Over the longer-term, long duration multi-hour and even multi-day storage providers will be needed to ensure system adequacy with higher levels of renewables as highlighted in Baringa's 'Pathway to a zero-carbon power system in Ireland' referenced in the next section.

Currently the majority of battery storage projects are developing under the DS3 system services arrangements to provide fast frequency response and operating reserve services that are important to help manage an electricity system with high penetration of renewables.

However, there are still many barriers that are blocking the full integration of energy storage and preventing projects from stacking revenues across the wider storage use cases. There is a disjointed approach to many energy storage policy issues among and even within the various policy makers which risks policy misalignment and the creation of further issues down the line.

A coordinated strategy for energy storage is needed to ensure investment is supported through the various pillars of the market and that new energy storage technologies are fully integrated into the electricity system and market to unlock their full potential. This should bring together the relevant stakeholders such as the System Operators, Regulatory Authorities, Government departments and industry to ensure a coordinated approach to energy storage going forward. As a first step we propose that the TSOs establish a working group with industry, potentially through FlexTech, to start to coordinate and progress some of these issues.

[1] https://windenergyireland.com/images/Article_files/Final_Baringa_70by30_Report_web.pdf

Achieving the Renewable Target – ESI Response to Questions 1-5

ESI fully endorse Wind Energy Ireland's submission to the SOEF Consultation relating to Baringa's 'Pathway to a zero-carbon power system in Ireland' study which is submitted as an accompanying appendix to Wind Energy Ireland's response.

The analysis shows that the emissions footprint of the electricity sector in Ireland can be reduced substantially beyond the 4 - 5 Mt of CO_2 objective of the Climate Action Plan 2019 by 2030, and it concludes that:

1. Government should **maintain the Climate Action Plan 2019 and Programme for Government renewable capacity targets** for onshore wind (8.2 GW) and offshore wind (5GW) for 2030, along with 5 GW of solar PV.

2. An **emissions target of less than 2 million tonnes of CO_2**:
   - Is very achievable by 2030;
   - Does not require a significant change in the approach currently underway to achieve 70% renewable electricity;
   - Can be met by implementing more of existing technologies that are proven today (such as energy storage); and
   - Can be achieved at a lower cost to the end consumer (saving approx. €150m per annum).

3. A **stretch target of a zero-carbon power system by 2030 is possible**:
   - It requires incremental investments in a suite of new technologies including long-duration energy storage; and
   - It requires the introduction of a carbon price floor in I-SEM.

We strongly endorse these positions and recommend that the final SOEF roadmap sets out a path to deliver these renewable capacity targets, and ultimately a net-zero emissions power system, with a framework to support investment in necessary supporting technologies such as energy storage.

Power System Assumptions – ESI Response to Questions 6-10

In relation to the assumptions used we have a concern regarding the detail of this approach in that the SysFlex work, upon which the approach to System Operations appears to be built, only includes one of the TES scenarios which meets the 70% RES-E target for 2030. Also, while the SysFlex 70% RES-E scenario is used for defining the technical scarcities for System Operations this is quite different to the TES 70% scenarios used for Transmission Network requirements e.g. 1300MW large-scale storage in SysFlex vs 600-900 MW large-scale storage in TES. Does this present a problem for the modelling – e.g. a gap in needs assessment either on the network or the operations side?

The TES analysis appears to be underestimating the levels of battery storage considering the projects already connected or planning to connect in the coming years. We estimate that there will be between 600-700 MW of battery storage, primarily short duration providing fast acting reserve, on the system by the end of 2021/beginning of 2022. Our pipeline analysis shows that there is a further 1,500 – 2,000 MW of storage projects in development today with many planning to connect post 2022. With the policy landscape focusing on the need for system adequacy in the coming years and the need to alleviate network constraints in congested areas of the grid it is likely that technologies such as energy storage will play a greater role in other markets such as capacity, energy and congestion (when this service is defined) and there will be a shift towards longer-duration storage projects. Given the data freeze for this analysis in 2019 we believe the final roadmap should reflect the levels of storage already connected or soon to connect on the system and the capacities assumed for longer-duration storage should increase to reflect the size of the pipeline today. These projects will play an important role in system adequacy and network congestion reducing the need for fossil fuel generation or network build out. We are happy to provide details on the energy storage pipeline to assist in this analysis.

Transmission Networks – ESI Response to Questions 11-16

Our comments are in relation to all the network scenarios analysed as we believe technologies such as energy storage can play an important role in alleviating or deferring the need for grid development in certain areas of the country and optimising grid capacity for generation and demand customers. Virtual battery networks use large batteries to tap into the back-up transmission capacity (N-1). It does this by absorbing power during system events over a 30 minute period which provides a buffer for the TSO to safely redispatch generation in the region to avoid overloads (link to TENNET description). This is a solution that has the capability to provide early capacity and can be used to reduce constraints. Battery technology is also modular and portable so if the system need changed over time the grid booster technology could be moved. In January 2020, BNetzA (German TSO) confirmed two grid booster projects with a combined capacity of 450MW. We believe the TSOs should carry out a full assessment of the all-island network to identify the optimum location and size for grid booster technology. TENNET are also looking to deploy Grid Booster technology and have conducted a market survey in March 2020 to prepare for the award of contracts and inform the market players. We would encourage the TSOs to conduct a full study of the network to establish where this technology can be utilised and how much N-1 capacity it can release. The TSOs could then conduct a market survey, similar to the one that TENNET did, with locational signals to kickstart procurement of these services.

Similarly, a locational congestion product should be developed to provide a signal for investment in technologies that can alleviate congestion in constrained areas of the grid, e.g. demand centres such as Dublin where energy storage could help meet peak demand requirements and reduce the need for grid reinforcements and on the generation side to reduce the dispatch down of wind and solar and shift excess renewable generation to meet demand at other times.

Hybrid projects are also another solution to optimise existing generation sites and grid infrastructure while minimising renewable dispatch down and reducing project development costs. To date very little progress has been made in resolving policy and regulatory barriers such as multiple legal entities behind connection points and sharing of MEC for separate technologies behind a connection point. Many wind and solar projects could install battery storage on existing sites relatively easily provided that they can make use of their existing MEC. These storage projects could be used both as a means to reduce dispatch down for wind and solar sites by absorbing and then discharging energy at times of high/low renewable generation (thus improving capacity factors) but also as a service provider to the grid at times of low renewable generation. Unlocking the potential for hybrid projects has significant benefits and should be progressed as a no regrets option in any network scenario. We recognise that hybrid connections fall under the FlexTech programme which is pillar called out under the System Operations pathway but progress and clarity is needed on these issues urgently to allow projects to take advantage of the opportunities and increase the efficiency of the grid.

We believe solutions such as these could be applied in any of the network scenarios outlined and should be incorporated into the final approach as an option for specific locations to be progressed in parallel with wider network reinforcements.

System Operations

ESI Response to Question 17. Have we adequately explained the operational challenges associated with meeting the renewable target?

We believe the challenges have been well explained and there is good detail on the different concepts. We refer to our concern in Section 2 on the Power System Assumptions and potential misalignment between the SysFlex and TES scenarios in terms of system needs assessment.

ESI Response to Question 18. Do you have any comments in relation to the technical scarcities and operational challenges identified? Are there challenges that you foresee that we have not discussed?

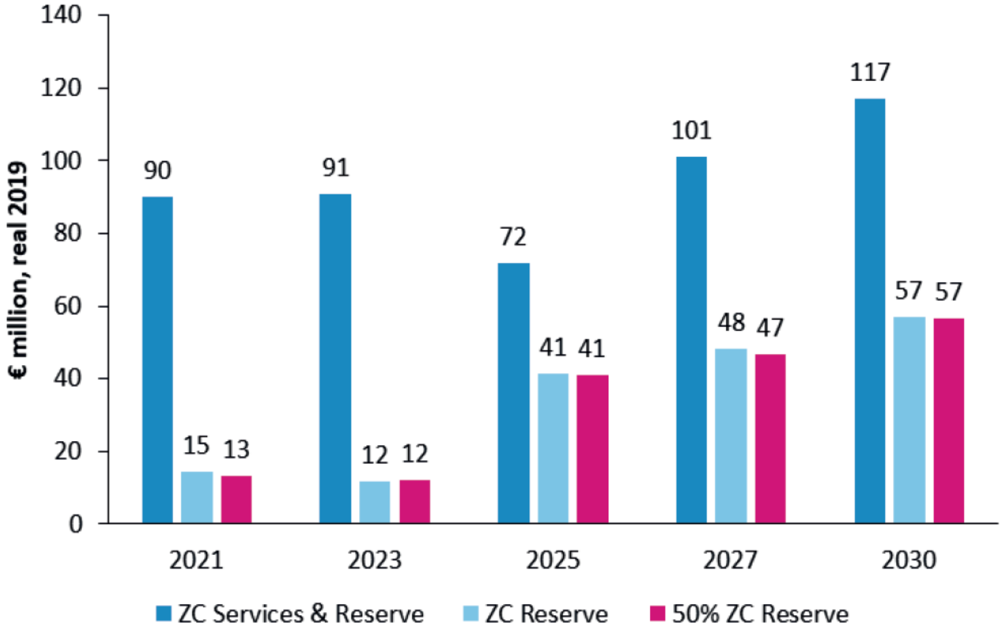
We believe the technical scarcities in 2030 have been well described but we believe more focus is needed on the solutions to meet these challenges. The programme for 2030 must do more than simply deliver the required volume of system services, operational tools and policies by 2030 and should include decarbonisation as a central goal, in line with national energy policies and the strategies of the Regulatory Authorities and the System Operators in Ireland and Northern Ireland.

We propose that the key objective of the operational programme for 2030 should be to deliver a system that is capable of operating with full zero-carbon system services by 2030 and no minimum generation constraint. This would essentially mean that the system is capable of operating with 100% of demand being met by renewables at any one time and all system service requirements being met at these times by zero-carbon technologies.

Baringa's Store, Respond and Save report[2], shows that already today the consumer would benefit to the tune of €90 million per annum if the system were transitioned to one where zero-carbon sources can meet all system service requirements at any one time. This value increases to €117 million per annum by 2030 as shown below. That is because the System Operators would no longer have to constrain on conventional plant and pay the associated fuel costs for them to provide these services.

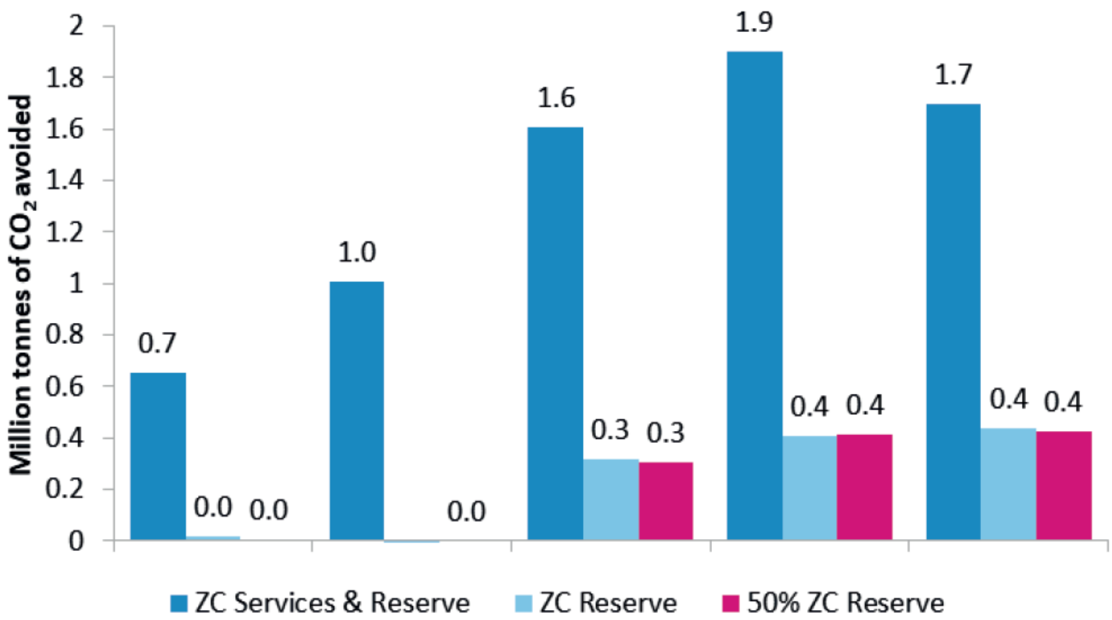
[2] https://www.energystorageireland.com/wp-content/uploads/2020/02/Energy-Storage-Ireland-Baringa-Store-Respond-Save-Report.pdf

Figure 2 Annual operational cost savings generated by using zero-carbon technologies to meet reserve and system services



In addition to cost savings, the early transition to zero-carbon system services will have a huge impact on renewable curtailment and on emissions. Already today, we could avoid 700,000 tonnes of CO2 emissions by transitioning to zero-carbon services as shown below. The avoided emissions tally increases to close to 2 million tonnes per annum in 2030. The technologies exist today to move to a zero-carbon system services system and this framework should facilitate that transition.

Figure 4 Annual avoided SEM CO_2 emissions from zero-carbon system services



The technologies to deliver these services exist today. To deliver this clear investment signals in terms of service design, volume needs and procurement timelines are needed. Below we have outlined potential volumes required for 2030 and existing zero-carbon technologies that can provide these services.

Table 3 Zero-carbon system service providers and potential capacities required in a 2030 70% RES-E power system

System Service	Potential Capacity Required	Example zero-carbon technologies
Reserve	700-1,000MW of Reserves – 500ms to 1 hour	Battery storage, domestic and large energy user demand-side response, renewables
Inertia	20,000 MWs	Synchronous condensers
Reactive Power	±3,600 Mvar	STATCOMs, renewables, battery storage
Ramping	1,500 MW – 1 hour, 3000 MW – 3 hours, 4,000 MW – 8 hour	Long-duration storage, pumped hydro, demand-side response

ESI Response to Question 19. Are there technologies that could help mitigate some of the technical challenges that we have not mentioned?

We broadly agree with the range of technologies identified to mitigate the technical challenges listed. However, the consultation focuses a lot on the potential of demand side response from residential customers to provide TSO system services such as fast acting reserves but also notes that there are significant challenges and barriers to residential demand side response. We note that there are already significant volumes of battery storage, large-scale DSM and wind generators operational today that can provide these services. While allowing this potential from residential DSM would require significant work in terms of Grid Code, market and system operations changes we believe focus should be placed on allowing full market and system integration of existing service providers such as battery storage, large-scale DSM and wind instead. There is already, or soon to be, sufficient volumes from these technologies to meet existing and future fast acting reserve requirements.

It is our view that demand side units will be better placed to respond to distribution-level constraint issues as a congestion service provider. It is extremely likely that as we deploy increased volumes of electric vehicles and residential heat pumps on the distribution system that this system will come under considerable strain. Likewise increasing demand from large industrial users has the potential to put the electricity system under strain during periods of peak demand. Deployment of demand side response can be a very effective means of managing these peak load periods over a short number of hours thereby reducing (though not removing) the need for network investment.

ESI Response to Question 20. Do you have any comments on the approach we are taking to system services product design?

The approach to model potential technical scarcities and then design and review of system service products to address these certainties makes sense. We have commented previously that this system services framework and product design must be developed with a target of a of zero-carbon system services model by 2030 and to get to this, more clarity is needed for investors in new zero-carbon technologies on future system service needs, investment frameworks, procurement timelines and volume needs.

In addition to those already presented we believe new services or products should be addressed in the final SOEF roadmap as follows:

- Negative reserve is noted as a technical scarcity in 2030 but does not appear to be highlighted as a potential future product. There are existing providers that can deliver this service such as wind and battery storage but it has not been defined as a system service and there is currently no specific remuneration in place to incentivise provision.
- More detail is needed on the congestion product and other locational services that could be used to alleviate network constraints. There are a number of potential providers that could deliver this service but clarity is needed on issues such as the type of duration(s) for such a product, locations on the network that it would be required and whether from the network perspective it is on the demand side or generation side (or both). Where zero / very low marginal cost technologies are suitable, they will likely be deployable on the grid at lower costs if they are provided with greater long term revenue certainty. In this respect, the design of the service may in fact determine whether the technology solution can be delivered in a commercially viable / sensible manner for consumers.
- Grid forming technologies are mentioned in the roadmap but not necessarily within the 2030 timeframe. We believe this warrants further consideration particularly given the potential for technologies such as RES and battery storage to provide these valuable stability services. The benefits are that these technologies can provide multiple services thus allowing revenue stacking opportunities across different services and driving more efficient investment.

We have made more comments in relation to the system services market design under question 27.

ESI Response to Question 21. Do you have any comments in relation to the evolution of operational policy out to 2030?

In order to ensure successful delivery of the targets in the PfG it is essential that proper policy is put in place that is functional from the outset. To this end it is important to look at, and learn lessons from, occasions where this did not happen in the recent past. An example of this would be FlexTech where engagement between the TSOs and industry has been slow and often not forthcoming, leading to a degree of frustration in industry and much delayed start to the roll out and delivery of the project. It is therefore welcome to see FlexTech highlighted as one of the four key pillars underpinning the Operational Pathways to 2030 programme and we look forward to working with the System Operators and removing the barriers to the integration of these important technologies.

One such area under FlexTech we would like to highlight is the issues affecting the full integration of battery storage projects into the market and preventing the optimal use of the assets.

The Trading & Settlement Code (TSC) envisages the main mechanism for managing the state-of-charge of energy storage to be via the ex-ante and balancing markets. However, as identified below there are currently a number of known technical limitations that prevent this, in particular associated with the charging (import) of batteries via the ex-ante markets or the balancing market. This creates a number of issues not just for the commercial interests of asset owners and operators, but also in terms of preventing the efficient use of these flexible and zero-carbon assets on the system by the TSOs.

The key limitations involve IT and market systems as follows:

a) There is no capability for current market interfaces (MPI) to accept and process 'negative' Physical Notifications (PNs) into central scheduling, for charging of batteries;

b) Standard dispatch tools (EDIL) do not have the capability to relay 'negative' MW instructions for charging (even if negative PN actions could be submitted as envisaged under the TSC) – although the TSOs note the possibility to use telephone instructions here;

c) The lack of an appropriate battery storage market model, which results in storage units being registered and setup as 'Multi-Fuel Generator' Units, which do not support a full operating range of export/import and preclude operation in the balancing market for charging.

The TSOs have noted that fixes to remove the current IT and market systems issues and allow battery projects to participate in the market as intended under the TSC will take an extended period of time to put in place. It is imperative that these solutions are progressed as quickly as possible to allow the most effective use of batteries on the system. It is important that a roadmap is set out to get to this enduring solution to provide clarity and certainty to industry.

In the meantime, in advance of the commercial operation of a number of battery storage projects on 1 April 2021, the TSOs put in place an interim solution to allow some form of charging for these projects so they can provide their contracted services. This effectively allows battery units to charge up to a pre-agreed charging level (up to the lower of 5 MW or 20% of MEC, MIC) while any charging above this level would require engagement and agreement with the TSOs' control centre.

We recognise that the approach above was a pragmatic step given the imminent commercial operation of a number of battery projects. However, we believe more engagement is needed with industry to build on this interim approach to ensure the most appropriate solution for the different types of battery projects already connected and connecting onto the system in the coming months. There is a significant risk that the current approach disproportionately impacts larger projects or projects with more symmetrical MEC/MIC ratios that then leads to stranded investments and inefficient use of the assets.

We also emphasise the downstream impacts that this proposal has for the wider market and market participants. The industry needs clarity and transparency on which batteries are charging, when and to what extent through the relevant market reports, notably but not only to understand the system NIV at any time. Transparent and clear information is a basic foundation of a properly functioning and efficient market.

We believe there are options that can be discussed and progressed to build on the approach already in place and we request engagement with the TSOs via a workshop or industry meeting as a first step and that these issues are addressed in the final SOEF roadmap.

ESI Response to Question 22. Do you have any comments on the Operational Pathways to 2030 objectives, programme or key milestones?

We believe the following two objectives will be essential to the Operational Pathways to 2030 programme and should be included in the final SOEF Roadmap:

1. The electricity system must be capable of operating at any one time with zero carbon system services by 2030 (i.e. 100% SNSP) and without a 'minimum generation units online' constraint on the system.
2. The TSOs to start measuring and reporting on energy market and non-energy market (non-energy action) emissions and the cost of the constrained run. The TSOs often position units away from the energy market schedule in order to meet system service requirements or due to network constraints. These are known as non-energy actions. Our recommendation is for the TSOs to model electricity system CO2 emissions to compare energy market emissions and actual electricity generation emissions to calculate the non-energy market emissions contribution. Or in other words, the emissions solely related to actions that are required to ensure the electricity system remains stable. As new low carbon system service and other flexible technologies come on the system it will be important to track and measure how these are being utilised and their impact on power sector emissions. Right now this is not being measured and so it cannot be managed.

We strongly recommend that the TSOs start to measure and report regularly on 3 key metrics:

I. Dispatch Down (per current Dispatch Down reports)

II. Energy market and non-energy market emissions

III. The Dispatch and Balancing Cost

A quarterly or monthly report could have a summary table along the lines of the example below:

Quarter 3 2021 EirGrid Key Operational Metric Report					
Curtailment			DS3 Spend (€m)	DBC Spend (€m)	CO2 Emissions due to Constrained Market Run (tonnes)
Total (%)	Min Gen (%)	SNSP (%)			
10	8	2	50	60	250000

Electricity Markets

ESI Response to Question 26. Do you have any comments on our findings and recommendations in relation to the capacity market component of our review?

We agree that a review of the capacity market is needed to support new investment in low carbon technologies and avoid locking in inflexible generation for years to come. To date the capacity market has been geared towards conventional thermal plant but this focus needs to shift and a review of the market carried out to ensure investment is delivered in the technologies that can support renewables and our capacity needs over the longer-term. We agree an approach that more accurately models and reflects the potential contributions of providers like energy storage to capacity requirements is needed. Strict emissions limits could be considered here for new build contracts in future capacity auctions to support new zero carbon technologies. For instance, in Spain the Government are proposing that long-term capacity contracts will only be provided to zero emissions technologies.

We also support a holistic approach to the various pillars of the market which allows revenue stacking across different revenue streams and does not penalise or restrict providers from access to different markets.

ESI Response to Question 27. Do you have any comments on our findings and recommendations in relation to the system services component of our review?

While the consultation notes the intention to move from a price based to a volume based procurement framework for system services this should be considered in the context of the need to provide long-term investment certainty for new build technologies that will be required to meet system requirements out to 2030 and beyond while facilitating higher SNSP levels.

While a move to short-term competitive auctions for certain services, or volumes of certain services, is partly being driven by European requirements we understand there is still flexibility on the part of the relevant authorities to procure services through alternative mechanisms where new investment is needed.

We support market-based (i.e. short-term) procurement of system services where sufficient volumes of zero-carbon service providers have built out to provide adequate competition for meaningful market-based procurement. This is not the case for any system service today. While it is possible that there will be sufficient volume of zero-carbon reserve providers (i.e. batteries and DSUs) built out over the next 1-2 years for current requirements, this may not be the case when reserve requirements increase with the connection of the Celtic interconnector, anticipated in 2025/26.

For other system services there are inadequate or non-existent zero-carbon options connected to the grid today i.e. inertia and reactive power. In the future there will be also new requirements for localised services such as congestion management.

In order to deliver zero-carbon alternatives for these services at sufficient volumes to facilitate a working market-based system, a level of investment certainty must be provided to those units to allow them to build out first.

Adequate investment certainty formed a key principle of the original DS3 system service high-level design[3]. The zero-carbon reserve market in Ireland (primarily delivered by battery technology and Demand Side Units) was seeded by the fixed-term auction procurement framework, backed up by the presence of a regulated-price tariff procurement regime of shorter term and higher uncertainty. These frameworks have been successful in delivering new-build zero-carbon providing units which is probably adequate for the needs of the 2020 system. But the system will need more new-build zero-carbon service providers well in advance of 2030 for reserves and other services such as inertia, reactive power and future services such as congestion management. These units will require an adequate level of certainty to invest and deliver when they are needed. It is important to note that it is not enough to deliver a decision on a long-term daily auction framework linked to some future volume forecast. Any such market will need to be up and running for a period for investors to get adequate understanding of the price risk. In advance of that, new-build units will need an alternative framework to invest.

Long-term contracts or a form of long-term price certainty are a traditional and widespread means of delivering new investment (e.g. RESS and Capacity market auctions). ESI's view is that locking out new investment will very likely result in an outcome which is not economically efficient, particularly where this new investment is needed to support a 2030 system and brings significant additional consumer value in terms of facilitating integration of renewable generation and lowering emissions.

We would also like to highlight the importance of clarity on future volume requirements for system services to help developers ensure they are developing the right project in the right place at the right time. We see value in the concept of a system service forecast statement containing elements of location and volume forecasting for system services as well as indication of definition and timing for any new system services that may be required. This is a similar principle to that which is carried out in GB where both near-term and long-term signalling for service volumes and service requirements are frequently published by National Grid.[4]

We do note however that scarcity signals or long-term volume forecasts do not adequately address revenue risk, something which is difficult to predict or invest in under short-term auction arrangements.

Timely investment in system services is required to ensure emission reduction targets in both Ireland and Northern Ireland can be achieved. The issue for investors under the current DS3

[3] https://www.semcommittee.com/sites/semcommittee.com/files/media-files/SEM-14-108%20DS3%20System%20Services%20Decision%20Paper.pdf

[4] https://www.nationalgrideso.com/industry-information/balancing-services/frequency-response-services/firm-frequency-response-ffr?market-information

market arrangements however is revenue risk. This is highlighted by the ongoing TSO consultation on DS3 system services expenditure review which emphasises the revenue risks that new build projects face.

In the absence of volume controls and guaranteed budget increases, investment will result in lower market pricing, and therefore reduced returns. The market is also a monopsony – i.e. the TSOs act as the sole buyer of services - and therefore affords little opportunity for product differentiation – i.e. there are limited mechanisms to protect market share as the provision of services increases. Investment under the current DS3 arrangements is therefore subject to significant risk that manifests in a myriad of forms, including system SNSP levels, budget caps and wider regulatory risk. Over time these market dynamics, which are outside the control of the investor, are likely to significantly erode investor confidence in the market.

The introduction of daily auctions for system services will not address these issues for new investment, even with the introduction of scarcity pricing, and especially if there are regulated price caps. Short term daily products do not deliver any more revenue certainty than the tariff regime, and, in fact, potentially offer less, while scarcity pricing, by definition, only out-turns when insufficient investment in required services occurs. If sufficient investment in service provision is secured scarcity pricing will not be paid to investors. If the scarcity price is administered it is subject to regulatory risk, while implementation of regulated price caps removes a guarantee to market participants that they can extract required scarcity rents from the market. From the perspective of the customer, if scarcity prices are paid then the market has failed to deliver the required services, while on the other hand the absence of price caps would leave consumers open to the potential abuse of market power. The accepted way to address these issues is to implement longer-term fixed price contracting mechanisms to underwrite capital intensive new investments. These mechanisms provide revenue/cost certainty to both sellers and buyers and offer protection to investors and customers from the vagaries of market risk. This is why the current capacity market in I-SEM offers a 10 year fixed price contract, despite there being a regulated scarcity pricing mechanism.

In an evolving technological landscape ESI recognises the need for flexibility in procurement approach. While we acknowledge the TSOs' concerns around locking in long-term contracts and the risk of over-paying we see that this needs to be balanced against the need to deliver volume in a timely manner. We believe the combined approach of fixed-contracts for some volume with more flexible procurement mechanisms is worth considering. Underinvestment in system services over the long term will result in high levels of renewable curtailment, stall investment in renewable technologies, and is likely to cost the consumer substantially more than the cost of over investment in any given technology in the short term, particularly flexible, versatile technologies such as battery storage. Furthermore, these short-term risks can at least partly be mitigated by the TSOs via their procurement process – e.g. timing, product requirements, volumes each contracting round, etc.

In theory long-term contracting mechanisms can be separated from underlying market arrangements, providing there is certainty on the products or services required over the duration of the contract. In practice however the underlying market arrangements are likely to determine the costs and financial risks of delivering upon contractual obligations, and therefore cannot be ignored. ESI therefore recommends a workstream is set up to investigate these issues and to provide options for further consultation based on previously successful investment support mechanisms, such as REFIT, RESS and the Capacity market.

It is also worthy to note that there has also been considerable re-design and development of system services in GB, under National Grid ESO's 'System Needs and Product Strategy' (SNaPS) programme.[5] This programme has sought to incrementally re-design and introduce new system service products to ensure they better reflect the needs of a future system, increase accessibility and enable better use of new technologies and sources of flexibility. The program strategy was originally outlined in 2017 and envisaged a two-year work programme (which is still ongoing). The approach to introducing new services has typically been incremental, for example with new auction frameworks trialled alongside existing arrangements. These trials procure limited volumes from providers willing to participate. Crucially, existing arrangements for procuring system services continue to operate in parallel, until learnings from the trials are evaluated and re-implemented. This has allowed the TSO to be more agile and learn from practical implementation of new systems & frameworks, working with providers to get designs and systems working correctly before introducing more widely to the whole market. It is strongly suggested to replicate a similar approach, given the scale of changes anticipated.

Finally, the current DS3 system services cap of €235m per annum was put in place to reach 2020 targets. It logically follows that it must now be reviewed and revised upwards to ensure the 2030 targets are met. The CRU has set targets in the PR5 framework for EirGrid to reach 80% SNSP by 2023 and 85% SNSP by 2025. This ambition must be supported by adequate resources and funding to deliver the technologies and services required. The DS3 tariff arrangements have been extended until 2024 but this must be considered in the context of the additional budget requirements needed to maintain a clear and strong investment signal. Without this there is a risk of stalling investment in new system service technologies and limiting our ability to increase SNSP levels.

The EU-SysFlex study *'Financial Implications of High Levels of Renewables on the European Power System'*[6] estimates that the value of system services, due to avoided production costs and avoided cost of carbon, is over €750 million per annum in EirGrid's Low Carbon Living scenario (the only scenario that meets 70% RES-E in Ireland). The study also argues that the true value is likely much higher as there are many other externalities that are not easily captured.

[5] https://www.nationalgrideso.com/sites/eso/files/documents/Summary_SNAPS_Consultation_vFinal.pdf
[6] https://eu-sysflex.com/wp-content/uploads/2020/05/Task_2.5-Deliverable-Report_for_Submission.pdf

We understood that the TSOs have contracted consultancy support to validate this analysis and we would welcome further clarity on the outcomes of this work and how the current DS3 system services budget will evolve with a glide path to meet 2030 requirements.

ESI Response to Question 29. Do you have any comments on our findings and recommendations in relation to network tariffs component of our review?

We welcome a network tariffs reviews and from the perspective of energy storage stress that this review takes into account the developing use cases for storage, particularly longer-duration storage that we will need for 2030 and beyond. There is the risk that focusing on a narrow use case for storage will have a significant distortionary impact on the development of the storage sector in Ireland in the medium to long term by disincentivising investment in longer duration systems. This would reduce the wider benefits that can be offered by storage technologies that are critical for integrating world leading levels of renewable generation on a small, heavily constrained, island system.

The recent CRU decision in relation to the PSO levy to only treat storage as an energy consumer on its house load consumption[7] is relevant here as the principles from that decision and the current consultation paper acknowledge that storage technologies represent a new class of 'unit' with unique characteristics that must be accurately reflected within market arrangements, as well as other commercial arrangements, such as network charging.

While the current interim network charging approach has removed G-TUoS for commercial storage providers in Ireland, and we understand a decision on this is expected in Northern Ireland, our view is that consideration should be given to a longer-term solution for storage technologies with network charging for import only based on the import required for serving house loads.

Such an approach would be consistent with the principles already established by the CRU in relation to the unique characteristics of storage assets; i.e. they are not an end consumer of the electricity they store (PSO decision) and cannot be a generator of the electricity they release, therefore they should not be treated as either a generation or demand customer under the network charging regime. Storage technologies rather increase the carrying capacity of the network and, aligned with the correct economic incentives that should be delivered via the wider market arrangements rather than network charging policy, this will increase their overall utility to end consumers. Hence network charging policy that distorts appropriate economic signals and reduces the utility of storage assets, and therefore the wider network, must be avoided over the medium to long term.

Provision of flexible demand response, and the wider business case for development of longer duration batteries in general, require MIC levels approximately symmetrical with MEC levels; a

[7] https://www.cru.ie/wp-content/uploads/2019/03/CRU19034-Application-of-the-PSO-Levy-to-Commercial-Storage.pdf

scenario disincentivised under the current tariff framework due to the application of D-TUoS charging, especially the MIC related capacity charge. It is this symmetry in relation to MIC/MEC that is particularly important to unlock the full flexibility of storage assets. A network charging policy that focuses on only one pillar of network tariffs will tend to skew investment signals and cause an imbalance that may not be in line with wider market signals or system needs.

The importance of flexibility on the demand side will only increase as system renewable penetration increases over the coming years. Reducing available flexibility on the demand side of the market via network charging incentives will only serve to increase curtailment levels and reduce the tools available to the TSO to manage the system with high levels of renewables. For instance, there are ongoing initiatives in the UK, such as the Constraint Pathfinder, that will rely on the rapid (below 100ms) absorption of energy from at least 2 hours storage duration to alleviate constraints and its associated costs in strategic network areas with high renewables, such as Scotland.

Network charging is not the appropriate mechanism to manage dispatch issues as they do not reflect real time changes in the cost of meeting and managing system demand. Dispatch signals should be delivered via energy market arrangements (energy, capacity and DS3) which in turn should reflect the wider system needs. There is a risk that too narrow a focus on perceived dispatch issues, and provision of DS3 system services, in formulating network charging policy for storage, rather than the underlying characteristics of the technology and its wider substantial potential benefits to the network, will skew investment signals artificially towards shorter duration systems. This may not be the most appropriate solution for the market or the issues the system will face in trying to integrate world leading levels of renewable generation over the medium to long-term.

Flexibility on charging is a significant factor in the business case for storage in allowing assets to maximise their availability for DS3 system service provision, quickly charge their assets to offset capacity market risk and by allowing units to maximise price spreads captured in the ex-ante and balancing energy markets; i.e. ability to charge and discharge assets during the lowest and highest price trading periods. Consideration of the flexibility required by storage assets, as well as the benefits provision of such flexibility provides to the wider system, should be carefully considered when formulating the enduring solution for network charging for storage assets.

Consideration should also be given in the enduring review to the network costs covered by ongoing network charges on storage technologies. Typically, generators pay full upfront connection charges accompanied by lower ongoing network charges. On the other hand, demand assets pay only partial connection charges, however, they face a higher ongoing network charge. To date connection applications for commercial storage have been processed by the System Operators in line with other generation technologies as provided for under the ECP-1 connection policy decision. As a result, commercial storage projects are subject to the full cost of connection costs. The current tariff framework means storage pays an upfront full connection charge, as it is treated as a generator for connection charging purposes, as well as higher ongoing network levies in the form of DTUoS.

A further consideration is alignment of jurisdictional network charging structures for storage. For example, D-TUoS charging policy is jurisdictional with different charging methodologies in Ireland and Northern Ireland. Implementation of D-TUoS on storage assets located in Northern Ireland will impact the business cases for projects differently than application of such charges in Ireland. This is a more pronounced issue for storage technologies compared to other generators or suppliers due to the high levels of MIC and MEC required by a storage asset to function to their full potential on the electricity system. Furthermore, if DS3 system service arrangements were to move more towards a competitive procurement framework, any arbitrary material differences in treatment under the network charging regime, or network charging levels, across jurisdictions would lead to an unequal playing field and distort competitive outcomes.

Conclusion

In conclusion we would like to thank the TSOs for the opportunity to respond to the SOEF consultation and we hope that the recommendations we have provided are included in the final roadmap.