FASS Programme

Day-Ahead System Services Auction (DASSA) Volume Forecasting Methodology Recommendations Paper V1.1

April 2025

Executive Summary

The current DS3 (Delivering a Secure, Sustainable Electricity System) System Services arrangements, which became operational in 2016, were designed to facilitate new and existing technologies and participants to provide the system services[1] required to maintain a resilient power system up to 40% renewable target underpinned by 75% System Non-Synchronous Penetration (SNSP).

In 2022, the SEM Committee (SEMC) outlined in its High Level Design Decision (HLD) on the System Services Future Arrangements[2] the need to move to a day-ahead auction-based procurement of appropriate system services to align with EU requirements and ensure sufficient provision of the required operational services to deliver future Renewable Energy Source (RES) targets. This paper also outlined the need for SONI and EirGrid, the Transmission System Operators (TSOs) in Northern Ireland (NI) and Ireland (IE) to; review and consult upon the products to be procured in such an auction, to develop and consult upon a locational methodology for product procurement, and to develop and consult on a methodology for determining system services volume requirements and the form, frequency, and granularity of annual and short term reports on the volume requirements.

The TSOs published a Volume Forecasting Methodology (VFM) consultation paper in October 2024, and held an industry webinar during the consultation period. The paper focused on the reserve products (Fast Frequency Response (FFR), Primary Operating Reserve (POR), Secondary Operating Reserve (SOR), Tertiary Operating Reserves (TOR1 and TOR2), and Replacement Reserve (RR)) approved by the SEMC in its Decision paper 24-074 on the Product Review and Locational Methodology in October 2024[3] (based on the TSOs' Product Review and Locational Methodology Recommendations paper[4] submitted to the SEMC in August 2024).

The VFM consultation paper detailed the TSOs' considerations in determining volume requirements for the reserve products on a day-ahead forecasting basis, where uncertainty on wholesale market outcomes, renewable forecasts and interconnector flows exist. The TSOs outlined the need to ensure sufficient provision of services to manage both frequency regulation requirements (keeping frequency within 49.9 Hz - 50.1 Hz) and larger potential frequency deviations (zenith/nadir) and higher Rates of Change of Frequency (RoCoF), as the levels of non-synchronous generation (wind, solar and HVDC imports) and volumes of interconnection increase in the coming years. The paper also set out proposed methodologies for a weekly volume forecast and an annual, ten-year look-ahead forecast. The TSOs received 13 non-confidential responses to the consultation from a cross section of the All-Island energy industry, and all responses have been published alongside this recommendations paper.

The responses received from industry have indicated there is, in general, support for the proposed volume setting approach and the forecast methodology. Several respondents also noted appreciation for the level of detailed consideration undertaken by the TSOs and the necessity to strike a balance between managing the uncertainty of reserve requirements at day ahead stage and providing a clear volume requirement to industry to inform their market bidding considerations. The responses from industry also include requests for more transparency on the proposed methodology, information utilised to inform the methodology, and the publication of the results. Several responses show that there is a need for the TSOs to provide more explanation to aid stakeholders' understanding of e.g. the operational objectives of reserves and the interaction between volume publication timeline, auction timeline and drivers of uncertainty. Following the detailed responses received and engagement at the industry webinar, the TSOs have re-examined the original proposals. This paper sets out the TSOs' recommendations to the SEM Committee to inform its

[1] System services are products, other than energy and capacity, that are required for the continuous, secure operation of the power system.

[2] System Services Future Arrangements High Level Design Decision Paper.pdf (semcommittee.com)

[3] SEM-24-074 Product review and locational methodology paper.pdf (semcommittee.com)

[4] DASSA Product Review & Locational Methodology Recommendation Paper (EirGrid),
DASSA Product Review & Locational Methodology Recommendation Paper (SONI)

decision on the VFM for the initial DASSA arrangements. Implementation of the final VFM will require detailed examination as part of work already outlined in the Phased Implementation Roadmap (PIR) V2.0 on Grid Code alignment, System Services Code development and TSO licensing workstreams (Milestones 8, 15, 22, 25). Further consideration of the mechanism to enable the proposed annual (Y+1-Year +10) forecast within TSO workplans and RA approved funding arrangements will be also necessary, and will be considered under the wider implementation of DASSA/FASS arrangements.

The forecasting of volumes is a complex process, as Ireland and Northern Ireland are at the leading edge of renewable integration, with limited interconnection, and with real-time demand and generation becoming more weather dependent. The TSOs consider these recommendations to be suitable for the initial DASSA auctions to ensure the TSOs have the capability to manage evolving challenges, such as the introduction of Low Carbon Inertia Services (LCIS), new HVDC interconnectors, the performance of new Large Energy Users (LEUs), new RES and new Battery Energy Storage Systems (BESS).

However, the TSOs also consider that the methodology will need to evolve over time to include improvements based on real-life operational experience, evolving ex-ante market dynamics and improved forecasting tools. In addition, at the time of publication of the VFM consultation, the SEMC had clarified that the TSO proposed Final Assignment Mechanism (FAM) had not been approved, thereby signalling that the TSOs had to rely wholly on the DASSA procured volumes to ensure availability of reserve requirements in real time. There has since been intensive engagement between the regulatory authorities and the TSOs to explore potential alternative solutions to the FAM; the outcome of this joint assessment process is that the TSOs will develop and consult with industry on a Residual Availability Determination (RAD) in early 2025, with a SEMC decision required thereafter. While there is therefore no approved alternative FAM solution available at the time of development of this recommendations paper, the TSOs have aimed to outline where the proposed RAD might alter the final VFM methodology.

The main changes compared to the consultation document include;

- More detail on the TSOs' proposals regarding the reference incident determination, including on the methodology for forecasting consequential losses and the methodology for determining the allowance for 'unavailable reserves' (see chapter 4).
- While the TSOs are continuing to recommend publication of the required volumes at 10am for DASSA go live as this offers participants visibility of the required volumes to inform their bidding strategy for both DASSA and the DAM, the TSOs recognise there may be an additional benefit of releasing an updated volume requirement incorporating increased knowledge from DAM results and updated RES forecasts. The TSOs will therefore ensure that IT system development for DASSA will allow for the capability to publish additional volume forecasts (after the DAM results and before DASSA gate closure) in future.
- The TSOs have started the initial development of day-ahead prediction tools which may assist the day-ahead reserve volume forecasts. Depending on the level of accuracy such prediction tools may provide, the TSOs may consider the introduction of a more probabilistic approach to volume determination. This, however, will be dependent on certainty of access to reserve volumes post DASSA auction (i.e. through an alternative to the original FAM mechanism e.g. RAD).
- Regarding interactions between different procurement mechanisms, the DASSA will be the primary procurement mechanism, with the proposed FAM replacement, the RAD, meeting the 'gaps' left by any lapsed DASSA Orders and meeting any additional reserve volume – above that procured in the DASSA - required to meet real-time system needs. The volumes that are required to be procured in the DASSA (and RAD) will be discounted by the volumes of DASSA reserve products that are contracted through other mechanisms if such contracts exist.

Accordingly, the key recommendations are:

- The required All Island reserve volumes for FFR, POR, SOR, TOR1, TOR2 and RR will be determined based on the system needs (e.g., aligning with the TSOs' operational policy on reserves) with two main objectives:

    - Maintaining frequency within 49.9 – 50.1 Hz range for 98% of time, as monitored and reported on annually in the All-Island Transmission Performance report. This means the system frequency will unlikely exceed the standard frequency range (49.8 to 50.2 Hz) more than 15,000 minutes/year (2.9% of minutes/year), as required by the EU System Operation Guideline (SOGL) and Synchronous Area Operational Agreement (SAOA).
    - Mitigating large disturbances (reference incidents) to avoid a maximum instantaneous frequency deviation larger than 1000 mHz from the nominal frequency of 50 Hz and a RoCoF larger than +/- 1 Hz/s, following the requirements in the TSOs' Operating Security Standards (OSS), SAOA, Load Frequency Control Block Operational Agreement (LFCBOA), and the SOGL.
- To meet the first objective above, the TSOs will annually review the frequency quality trend of the previous five years and assess the need for adapting the minimum volume requirements for dynamic reserves.
- To meet the second objective above, the TSOs will dimension reserve volumes to ensure that the relevant Reference Incident (RI) is secured against. Article 153(2)(b)(ii) of SOGL clearly outlines that the reference incident shall be the *'**largest imbalance** that may result from an instantaneous change of active power …'*. Such an imbalance can arise from the initial loss of the largest single infeed (LSI) e.g. importing interconnector or large generator, or the largest single outfeed (LSO), e.g., large demand unit or exporting interconnector, and, the consequential loss of additional generation or demand units as a result of protection setting response (e.g. driven by voltage changes from the loss of the LSI or LSO and lack of Fault Ride Through (FRT) capability of connected units), as explained further in Chapter 3.1. The TSOs propose therefore, that the RI will be determined separately for outfeed and infeed losses and will be the sum of the LSI or LSO and potential consequential losses. Note that given the relatively small size (i.e., with respect to the RI) and island nature of the All-Island power system, the TSOs consider that consequential losses can have a significant impact on system security if not properly mitigated. Note also that the TSOs aim for minimising consequential losses, by establishing adequate technical requirements that prevent consequential losses (e.g., developing standards for FRT capability of connected units).
- In accordance with the requirements in the SOGL, the TSOs propose that for DASSA the required downward and upward POR, SOR, TOR1, TOR2 and RR volumes shall be dimensioned to consider volumes required to meet 100% of the RIs for both outfeed and infeed losses.
- In order to facilitate all possible market outcomes and in the advance of certainty of dedicated opportunities for the TSOs to procure reserve volumes after DASSA, the TSOs will take a prudent approach in the preparation of the Day-ahead volume requirements of reserves (for publication at 10am) and assume that all system in-feeds and out-feeds that could be in service on the next day D may feed in/ feed out at their maximum capacity (i.e., RIs will include the impact of the maximum LSI and LSO loss during all trading periods of the following day. Potential consequential losses may be based, where possible, on a time-varying approach, e.g. as solar PV generation will not be at maximum capacity for the full day, the potential consequential losses may vary.
- In addition to the All Island RI, the TSOs will define jurisdictional RIs for both IE and NI. These jurisdictional RIs are set by the imbalance in each jurisdiction after a system separation caused by a trip of both circuits of the existing North-South (N-S) Tie-line. Consequently, the jurisdictional RIs are driven by the flow on the N-S Tie-line. Also, the jurisdictional RIs will need to take into account consequential losses that may occur if both circuits of the N-S tie-line trip. The need for jurisdictional RIs will be reviewed once the second N-S Interconnector starts operations.
- The minimum shares of dynamic response and the minimum shares for total FFR and FFR categories 1 and 2, relative to the RI, will be determined based on detailed simulations and outlined in the annual assessments. For example, based on simulation results for 2025, the TSOs expect that the required volumes of FFR would be typically around 70% of the RI for All Island, 80% for IE and 100% for NI. However, considering that the required FFR depends on available system inertia, the TSOs will evaluate inertia provision annually and will update requirements accordingly.

- In addition, the TSOs consider it important to account for potential loss of reserve provision from the units setting the LSI and LSO and will add a component to the DASSA reserve volume determination to cover this event.
- Also, the TSOs need to consider in the DASSA reserve volume determination the potential unavailability of reserve providing units, for example, one or more reserve providing units becoming unavailable due to a forced outage or a transmission restriction/fault which limits the provision of their service.
- By 10:00 each day, the TSOs will publish the required reserves volumes that will be procured in the DASSA on that day D-1 for the following day D. The TSOs will specify volume requirements for all upward and downward reserve products separately and will specify for each product minimum volumes per jurisdiction and minimum volumes of dynamic response. For FFR, minimum volume requirements for category 1 (Full Activation Time (FAT) = 150 ms) and category 2 (150 ms < FAT ≤ 300 ms) will be specified. The required reserves volumes will be published for all transaction periods of the following day D.
- The TSOs consider this VFM to be prudent given the uncertainties that exist at the day-ahead stage. However, the TSOs will aim to improve the accuracy of the reserve volumes forecasts over time and take steps to reduce the risk of consequential losses, noting that there may be challenges with implementation. Approaches under consideration include:
    - Development of day-ahead prediction tools of LSI, LSO, N-S interconnector flow and inertia levels. This may allow for more accurate day ahead volume forecasts and the possibility to differentiate the volume needs per trading interval. For this, the TSOs are starting to develop new forecasting capabilities, which will aim to provide enhanced information for the TSOs in determining day ahead DASSA volume forecasts. The development of such tools will require time to mature and will also need to account for changing market dynamics as a result of SEM-EU market integration.
    - The TSOs will prepare IT systems to enable the capability to publish updated forecasts after the DAM markets and before DASSA gate closure. Such additional forecasts will be subject to further considerations regarding accuracy of forecasts after DAM but pre intra-day market outcomes and the TSOs' ability to ensure sufficient reserve volumes after DASSA auction outcomes.
    - Reducing the risk of consequential losses, and accordingly the RI, through the development of new performance standards and capabilities that generation sources and demand should comply with.
    - Where appropriate, the TSOs aim to implement a time varying approach for relevant consequential losses from go-live. For example, solar PV generation will not be at maximum capacity for the full day, and accordingly the potential consequential losses may vary.
- The methodology recommended will enable the provision of a detailed forecast of requirements for Y+1, and a more indicative forecast of potential future reserve volumes for Y+2- to Y+10. The forecast for Y+1, will be informed by detailed assessments and supported by power system simulations and shall include detailed DASSA reserve volume requirements, including the characteristics (e.g., FFR FAT, dynamic) and location (IE, NI) for the next year. These forecasts will also provide necessary input to the subsequent weekly and daily volume determination methodologies. The TSOs recommend that the Y+2 to Y+10 forecasts should be updated annually to provide an overview of indicative required reserve volumes, including the characteristics (e.g., FFR FAT, dynamic) and location (IE, NI). Such an overview would include a high-level review of the reserve requirements for the next 10 years, taking into consideration anticipated changes in the transmission system and connected systems (e.g. new interconnectors). The implementation of the methodology will need to be formalised through the development of the system services code, the grid code review and the licencing and governance workstream, and the necessary funding and resources provided for.
- On a weekly basis, the TSOs will review the applicability of the results of the annual assessments and publish the guidelines, and parameters to be used for the day-ahead volume determination. The TSOs will aim to align this publication with the current Weekly Constraint Update.

- On a daily basis, the TSOs will utilise the information from the weekly forecast and update as required e.g. to account for new planned or forced outages, changing constraints on N-S tie-line flow, specific adverse weather situations e.g. storms, etc, enabling the publication of required DASSA volumes by 10:00 on D-1.
- The TSOs will implement functionality in the auction design that allows for implicit bundles of services for DASSA go-live in December 2026. As part of the Parameters and Scalars consultation, the TSOs will address questions relating to the products that would be implicitly bundled, volume requirements and the TSOs' willingness to pay for implicit bundles. Other categories of bundles, such as explicit bundles or those arising from linked bids, are not in scope for DASSA go-live; these will be addressed in a separate workstream as directed by the SEMC, the schedule for which will be captured in future versions of the PIR (from March 2025 onwards).
- To ensure sufficient reserve provision (as per the TSOs DASSA Design recommendations paper[5]) the TSOs recommend that service providers be obligated to declare their availability to provide a service to the TSOs if they are technically capable of doing so, irrespective of whether they hold a DASSA Order for the service volume. The TSOs also recommend that system service providers will be obliged to declare their forecast system services capability ahead of real time. The implementation of such requirements will be further detailed in the development of the System Services code.
- The TSOs reserve the right to take action (for system security reasons and to ensure we are able to meet our statutory obligations) to deviate from the annual, weekly or daily forecasted volumes if operational circumstances necessitate.

[5] SEM-24-066 - SEMC FASS DASSA Design Decision Paper.pdf (semcommittee.com)

Glossary of Terms

Acronym	Meaning
BESS	Battery Energy Storage Systems
DASSA	Day-Ahead System Services Auction
DPOR	Dynamic Primary Operating Reserve
DRR	Dynamic Reactive Response
DSO	Distribution System Operator
DSU	Demand Side Unit. One of more individual demand sites
DS3	Delivering a Secure, Sustainable Electricity System
FAM	Final Assignment Mechanism
FASS	Future Arrangements for System Services
FCR	Frequency Containment Reserves
FFR	Fast Frequency Response
FRR	Frequency Restoration Reserves
FRT	Fault Ride Through
HVDC	High Voltage Direct Current
LCIS	Low Carbon Inertia Service
LFCAA	Load Frequency Control Area Agreement
LFCBOA	Load Frequency Control Block Agreement
LEU	Large Energy User
LPF	Layered Procurement Framework
LSAT	Look-Ahead Security Assessment Tool
LSI	Largest Single Infeed
LSO	Largest Single Outfeed
MUON	Minimum Units Online
N-S Tie-line	North-South Tie-line
OSS	Operating Security Standards
PIR	Phased Implementation Roadmap
POR	Primary Operating Reserve
RA	Regulatory Authority
RAD	Residual Availability Determination
RES	Renewable Energy Sources
RI	Reference Incident
RoCoF	Rate of Change of Frequency
RR	Replacement Reserves

Acronym	Meaning
SAOA	Synchronous Area Operational Agreement
SEM	Single Electricity Market
SEMC	SEM Committee
SIR	Synchronous Inertia response
SNSP	System Non-Synchronous Penetration
SOEF	Shaping our Electricity Future
SOR	Secondary Operating Reserve
TOR	Tertiary Operating Reserve
TSO	Transmission System Operator. (SONI for Northern Ireland and EirGrid for Ireland)
TSS	Temporal Scarcity Scalar
VFM	Volume Forecasting Methodology

Table 1 Glossary of terms

Document History

Version	Date	Description of Changes
1.0	31 January 2025	TSOs' final recommendations paper as submitted to the Regulatory Authorities.
1.1	11 April 2025	Updates to include information and assessment related to one additional response.

Contents

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1. Introduction

1.1. Background

SONI and EirGrid are the Transmission System Operators (TSOs) in Northern Ireland and Ireland. It is our job to manage the electricity supply and the flow of power from generators to consumers. Electricity is generated from renewable sources (such as wind, solar and hydro power) gas and coal at sites across the island. Our high voltage transmission network then transports electricity to high demand centres, such as cities, towns and industrial sites.

We have a responsibility to facilitate connections to the power system including increased levels of renewable sources to generate on the power system while continuing to ensure that the system operates securely and efficiently.

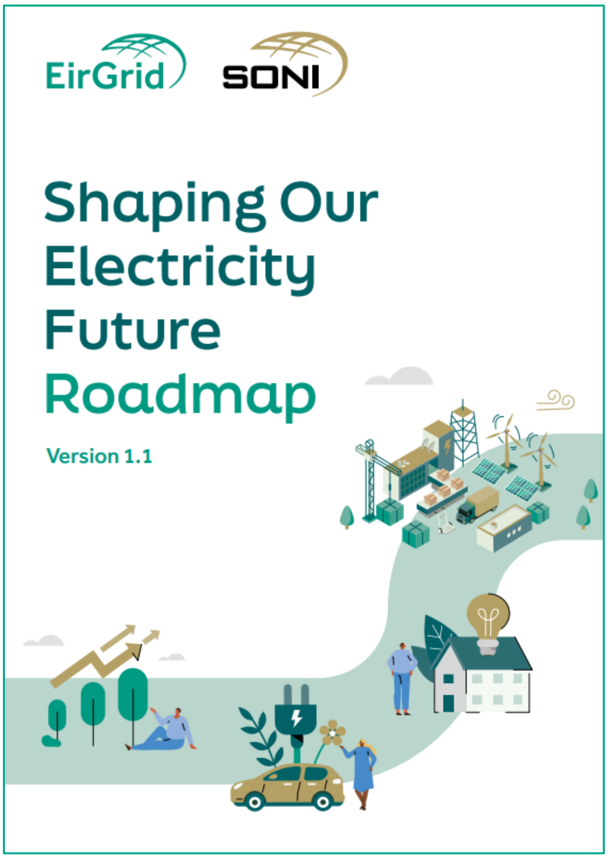
The DS3 System Services arrangements were designed to facilitate new and existing technologies and participants to provide the system services[6] required to maintain a resilient power system up to 75% SNSP. The next phase of the energy transition requires the implementation of new arrangements which are known as the Future Arrangements for System Services (FASS), which will include day ahead auction-based procurement of a subset of the System Services from 2026.

1.2. Shaping Our Electricity Future (SOEF)

In July 2023 we published an updated Shaping Our Electricity Future Roadmap[7] following consultation with stakeholders across society, government, industry, market participants and electricity consumers.

This Shaping Our Electricity Future Roadmap provides an outline of the key developments from a networks, engagement, operations and market perspective needed to support a secure transition to at least 80% electricity from renewable generation sources (RES-E) by 2030.

Inherent in this is a secure transition to 2030 whereby we continue to operate, develop and maintain a safe, secure, reliable, economical and efficient electricity transmission system.



1.3. Future Arrangement for System Services and Roadmap

In the SEM-22-012 High Level Design Decision on the System Services Future Arrangements[8], the SEMC specified a framework for the competitive procurement of system services. This framework consists of the following elements:

[6] System services are products, other than energy and capacity, that are required for the continuous, secure operation of the power system.

[7] Shaping Our Electricity Future Roadmap: Version 1.1 (eirgridgroup.com)

[8] System Services Future Arrangements High Level Design Decision Paper.pdf (semcommittee.com)

- A daily auction for the procurement of System Services within one day of energy dispatch,
- A Layered Procurement Framework for longer-term contracts and,
- The already established Fixed Contract Framework to remove barriers for new technologies.

The motivation for the High Level Design is to put in place the necessary framework for system services to support the integration of technologies which can facilitate a reduction in the quantity of carbon-intensive conventional generation required to run at any given time on the Ireland and Northern Ireland power systems. This reduction will facilitate the further integration of renewable generation and contribute towards achieving the 2030 RES targets set in both Ireland and Northern Ireland.

The SEMC also outlined in its High Level Design Decision the need for the TSOs to review the products to be procured in such a competitive framework, and the development of a locational methodology to address operational needs as required. Earlier in 2024, SONI and EirGrid, conducted and consulted on a Product Review and locational requirements for these Reserve services, which the SEMC issued a Decision paper on in October 2024 with the publication of SEMC Decision 24-074[9] .

The SEMC considered in its High Level Design Decision that having an accurate forecast of the volumes of system services required across timeframes, and having accurate historical data on the volumes available and required by the TSOs is critically important both for industry to make informed investment decisions and to enable the Regulatory Authorities to assess the effectiveness of market arrangements and inform policy decisions. In accordance with the High Level Design the TSOs are required to publish forecast and historic System Services volume requirements by service, and where relevant, by location.

1.4. Existing regulations that apply in relation to the dimensioning of reserves in the SEM synchronous area

The All-Island system operates as one Synchronous Area (SA), one Load-frequency Control (LFC) block and one LFC Area as defined by the SOGL Regulation[10]. As outlined in SOGL Articles 118, 119 and 120 the TSOs are obliged to develop a Synchronous Area Operational Agreement (SAOA), a Load Frequency Control Block Agreement (LFCBOA) and a Load Frequency control Area Agreement (LFCAA) which include dimensioning rules for Frequency containment reserves, Frequency restoration reserves and Replacement reserves. Article 6 (d) and (e) of SOGL also outlines the regulatory approval processes associated with the approval of certain aspects of the SAOA and LFCBOA. The regulatory authorities have approved the relevant aspects of these agreements as detailed in the respective publications by the UR[11] and CRU[12] in 2019. These agreements govern the operation and management of the LFC block and synchronous area as set out in the SOGL. Determining the volume of reserve required for each TSO's control area and ensuring that both TSOs maintain adequate system stability and security are governed by these rules.

While the dimensioning rules outlined in the SAOA and LFCBOA are focused on the processes and procedures the TSOs utilise to ensure safe and secure operation of the All-Island system, and thereby aim to ensure sufficient reserves are available to meet requirements closer to real time (i.e. post DASSA), there will be a need to ensure alignment between the considerations utilised in the VFM and the SAOA, LFCBOA and LFCAA. Therefore, as the VFM will consider future requirements based on changing system dynamics and in line with DASSA product recommendations (e.g. for downward reserves as well as upward

[9] SEM-24-074 Product review and locational methodology paper.pdf (semcommittee.com)

[10] SOGL Regulation - 2017/1485 - EN - EUR-Lex

[11] Approval of SONI's submission of amended Synchronous Area Operational Agreement & Load Frequency Control Block Operational Agreement | Utility Regulator (uregni.gov.uk), UR Approval of LFC Block Amended Proposal.pdf (uregni.gov.uk)

[12] CRU19140-Stakeholder-Letter-Decision-to-approve-Operational-Agreements-between-EirGrid.pdf (divio-media.com), CRU19140a-Joint-Decision-to-approve-Operational-Agreements-SAOA-and-LFCBOA-between-Eir.pdf (divio-media.com), CRU18238-CRU-Approval-of-amended-Load-Frequency-Control-Block-Proposal-in-accordance-w.pdf (divio-media.com)

reserve dimensioned per product), the TSOs and regulatory authorities will need to ensure that, as necessary, the processes set out in SOGL for updates to SAOA, the LFBOA and the LFCAA will have to be followed as necessary, including separate regulatory approval.

1.5. VFM Proposals and Phased Implementation Roadmap (PIR) Deliverables

The TSOs have created the VFM Consultation paper and this VFM Recommendation paper in line with the updated FASS PIR[13] to provide detail on the FASS product volume requirements. As has been agreed with the Regulators, this paper focuses on a VFM for the services that will be the focus of the initial Day-ahead Auction design i.e. the Reserve services.

Table 2 Services covered by this paper and services not covered by this paper

Services covered in this paper	Services not covered in this paper
FFR - Fast Frequency Response	RM1 - Ramping Margin 1
POR - Primary Operating Reserve	RM3 - Ramping Margin 3
SOR – Secondary Operating Reserve	RM8 - Ramping Margin 8
TOR1 – Tertiary Operating Reserve 1	FPFAPR - Fast Post Fault Active Power recovery
TOR2 - Tertiary Operating Reserve 2	SSRP- Steady State Reactive Power
RR - Replacement Reserve	DRR - Dynamic Reactive Response
	SIR - Synchronous Inertia response

In its High Level decision paper the SEMC outlined that the TSOs should assess the following aspects;

- *Develop and consult on a methodology for determining system services volume requirements and the volumes to be procured across all timeframes;*
- *Annually publish a ten-year forecast of system service requirements by relevant location, and shall invite comments from stakeholders on the form of this report at least annually;*
- *Regularly publish short-term forecasts and volume information following public consultation on the form, frequency, and granularity of these reports;*
- *Publish the volumes to be procured by auction on a daily basis. The SEM Committee directs the TSOs to progress the volumes deliverables as a matter of priority as per the PIR;*
- *Set-out a methodology that defines the volumes of the Reserves that are needed to be contracted after DASSA.*

The TSOs published their proposed VFM for industry consultation from October 4th to November 15th 2024, which address the above requirements, however the final requirement was not possible to be addressed fully in advance of certainty on dedicated opportunities for the TSOs to contract additional reserves after DASSA, following the SEMC decision to not approve the FAM mechanism in the SEM DASSA Design decision paper. Therefore, the TSOs had not outlined a methodology in the consultation paper for the determination of volumes to be procured after DASSA gate closure. The TSOs held an industry webinar on the proposed methodology on October 17th 2024.

Since the publication of the VFM consultation paper, intensive engagement between the TSOs and Regulatory Authorities on the development of an alternative mechanism to the FAM to ensure TSO capability to manage operational requirements (for implementation for DASSA go-live) has been undertaken. Further information on the outcome of this engagement is outlined in Section 3.2.1 and will

[13] FASS-TSOs-PIR-September-2024-EirGrid.pdf

be consulted on in early 2025. As outlined in this paper, the TSOs intend to enhance forecasting capabilities, to assist DASSA reserve volume forecasting as the system evolves to incorporate new SEM-EU market arrangements, new LCIS contracted providers, new HVDC interconnectors, additional LEU, new RES-E and new BESS. Additionally, as the Distribution System Operators (DSOs) in Ireland (IE) and Northern Ireland (NI) are currently developing flexibility service procurement processes, further work on the interaction with such services and service providers is proceeding under joint TSO/DSO workstreams[14].

This recommendation paper sits within the wider framework of the Future Arrangements of System Services and also considers aspects of the existing DS3 System Services arrangements. The publications listed in Table 3 may provide helpful context to the reader in their considerations of the topics covered in this paper and on the recommended for the products outlined.

These include the following:

Table 3 Published papers that are relevant to this topic of product design and locational methodology

Publication	Key points of relevance
DASSA Volume Forecasting Methodology Consultation paper[15].	TSO proposals on VFM for future system needs based on the reserve products approved by the SEMC in their DASSA Product Review and Locational Methodology Decision paper.
DASSA Product Review & Locational Methodology Recommendations Paper[16]	Proposed update of product definitions for DASSA, including the introduction of 'downward' reserve products; a reduction of the Full Activation Time (FAT) for FFR product to 1 second, with separate categories for a FAT of less than 300 ms and 150 ms; minimum capability requirements on configurable frequency deadbands, trajectories, reserve step sizes and reserve step triggers.
SEMC DASSA Product Review & Locational Methodology Decision paper[17]	SEMC Decision paper which approved the TSOs' proposed product designs for the reserve services, subject to a further product review being carried out in 2026.
DASSA Design Recommendations paper[18]	The TSOs' recommended design for the daily auction of system services following a 10-week consultation process, including the core DASSA mechanics, secondary trading, the commitment obligations and incentives associated with holding a DASSA Order, the ex-post Final Assignment Mechanism (FAM), and related functionality.
SEM Committee DASSA Design Decision Paper SEM-024-066[19]	This paper outlines the SEM Committee's final decisions on the DASSA arrangements and considerations for TSOs and market participants. It should be read in conjunction with the TSOs' DASSA Design Recommendations paper. It covers decisions on core DASSA mechanics, secondary trading, commitment obligations and incentives associated with holding a DASSA Order, the SEM Committee's decision

[14] TSO/DSO Joint System Operator Programme (eirgrid.ie), Appendix-2-Independent-Expert.pdf (soni.ltd.uk)

[15] https://consult.eirgrid.ie/en/consultation/soef-markets-%E2%80%93-future-arrangements-system-services-%E2%80%93-dassa-volume-forecasting-methodology

[16] DASSA Product Review & Locational Methodology Recommendation Paper (EirGrid),

DASSA Product Review & Locational Methodology Recommendation Paper (SONI)

[17] SEM-24-074 Product review and locational methodology paper.pdf (semcommittee.com)

[18] https://cms.eirgrid.ie/sites/default/files/publications/EirGrid-and-SONI-DASSA-Design-Recommendations-Paper-September-2024.pdf

[19] https://www.semcommittee.com/publications/sem-24-066-future-arrangements-system-services-dassa-design-decision-paper.pdf

Publication	Key points of relevance
	to not include an ex-post Final Assignment Mechanism (FAM), and other aspects.
Current System Services Volume Requirements Information Paper[20]	This Information Paper provides additional detail on the temporal impacts which alter both System Service requirements (e.g. as the Largest Single Infeed (LSI) varies) and the providers who can deliver those requirements (e.g. the market scheduled position of generators and Interconnectors).
DS3 System Services Tariffs[21] Consultation paper	This Tariffs consultation includes a breakdown of the contracted volume growth in System Services for each service procured, a breakdown of expenditure across technology types and the impact of the Temporal Scarcity Scalar (TSS).
System Services Indicative 2030 volumes [22]	This paper provided a summary of a single case study, the assumptions made (e.g. significant volumes of fast acting reserves from Demand Response available, gas turbines flexible enough to provide ramping services from a cold state), and analysis that examined three 2030 portfolios: • Gas Turbines-Led; • Mix; • Demand-Led. (consistency across the portfolios was included in terms of estimated new BESS, Interconnectors Renewable generation and some conventional assets). The analysis undertaken for this single case study demonstrated that the Available Volume for each portfolio would be sufficient to meet the real-time Requirements assumed. The portfolios on which this analysis is based are also likely to be different based on market forces and the TSOs are committed to a technology neutral stance.
SONI/EirGrid Synchronous Area Operational Agreement (SAOA)[23]	This document outlines the FCR (Frequency Containment Reserves, POR and SOR) dimensioning rules in Title 2 of this document along with other aspects of the operation of the All-island synchronous area. Only certain aspects of the SAOA (Title 2) are subject to regulatory approval.
SONI/EirGrid Load Frequency Control Block agreement (LFCBOA)[24]	This document outlines the FRR (Frequency Restoration Reserves, TOR1 and TOR2) dimensioning rules in Title 2 of this document, and RR dimensioning rules in Title 3 along with other aspects of the operational processes related to the All-island Load Frequency Control block. Only certain aspects of the LFCBOA (Title 2) are subject to regulatory approval.

[20] Current System Services Volume Requirements Information Paper

[21] DS3-System-Services-Tariffs-Consultation-27-March-2024.pdf (eirgrid.ie)

[22] System-Services-Indicative-2030-Volumes.pdf (eirgrid.ie)

[23] S1-SAOA-for-the-Ireland-and-Northern-Ireland-Synchronous-area-29.09.2022-(post-Title-2-approval).pdf

[24] S2-LFC-Block-Operational-Agreement-for-Ireland-and-Northern-Ireland-29.09.2022.pdf

Publication	Key points of relevance
SONI/EirGrid Load Frequency Control Area agreement (LFCAA)[25]	This document, while not subject to regulatory approval outlines considerations on replacement reserve requirements.

This paper outlines the TSOs final recommendations on a VFM which will be subject to a SEMC Decision as outlined in the PIR Roadmap V2 (See Figure 1). This decision will then be translated into formal processes and procedures via the development of the System Services code, the licencing and governance workstream and the grid code review.

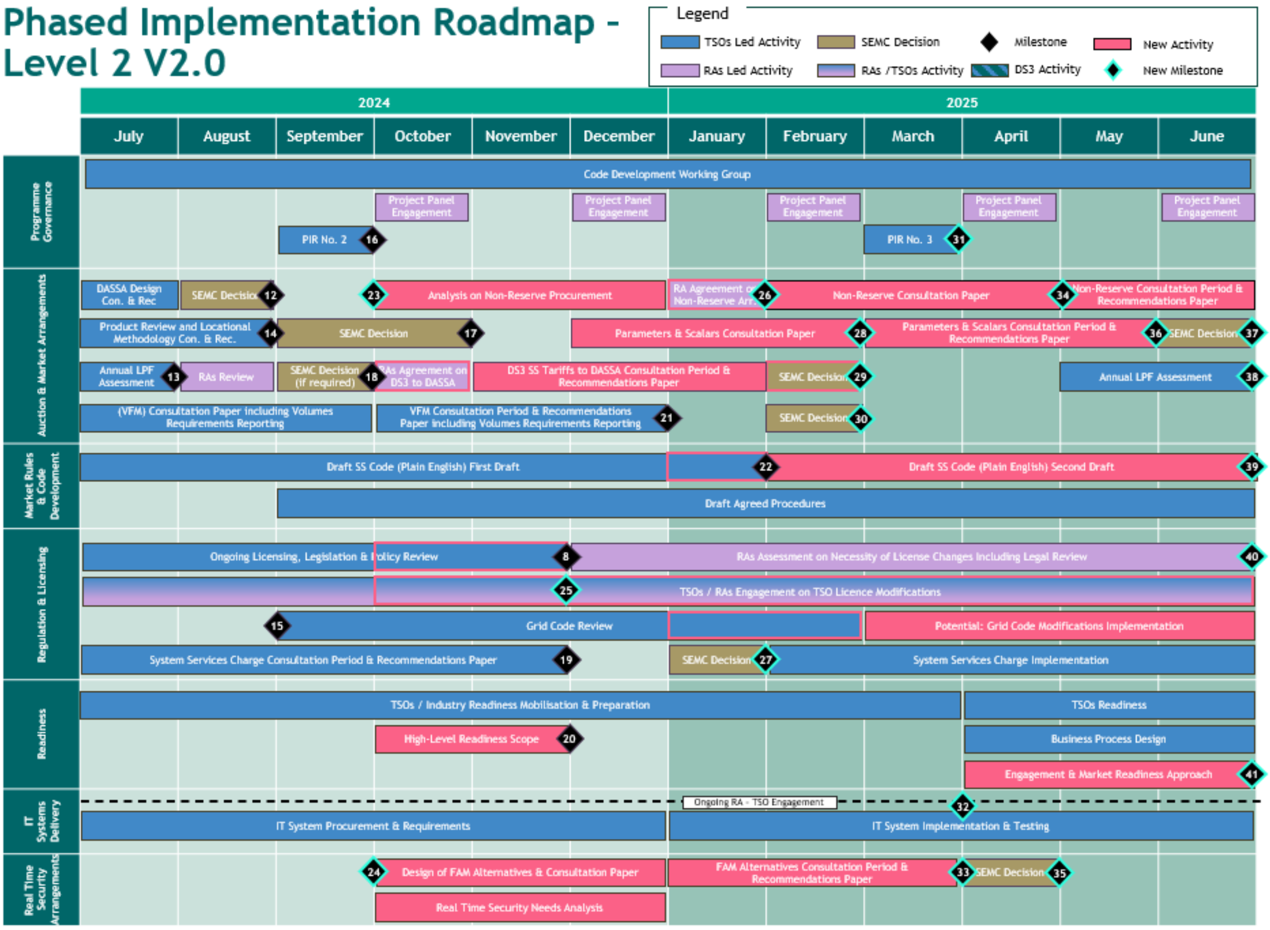


Figure 1 Level 2 V2.0 Phased implementation Roadmap showing Volume Forecasting work in 2024-2025

The TSOs' VFM Recommendations set out the process by which the required volumes of the Reserve Services will be determined for the purposes of the upcoming DASSA auctions which will be implemented in 2026. The products required for delivery of DASSA go-live in 2026 are the reserve services (FFR, POR, SOR, TOR1, TOR2, RR). The forecasting of volumes is a complex process, as IE and NI are at the leading edge of renewable integration, with limited interconnection and where the real-time demand and generation is and will become more weather dependent. The VFM presented in this paper details the TSOs' considerations in determining volume requirements on a day ahead forecasting basis, where uncertainty on wholesale market outcomes, renewable forecasts and interconnector flows exist.

Twelve detailed responses were received to the consultation, with additional feedback received during the industry webinar. Detailed feedback has also been received from the Regulatory Authorities. The TSOs

[25] S3-LFC-Area-Operational-Agreement-for-Ireland-and-Northern-Ireland-16.12.2019.pdf (eirgrid.ie)

have welcomed all feedback, which has helped formulate the final recommendations on the VFM as outlined in this paper.

Examination of technical requirements and volume considerations for other System Service products will be examined as part of work ongoing on the non-reserve services (e.g., Ramping, Inertia, Reactive power) as outlined in the PIR, and will be consulted on in 2025.

1.6. Structure of this Paper

This recommendations paper is structured as follows:

Chapter 2 provides an overview of responses received that were not specific to individual consultation questions and outlines some of the common themes that have emerged from the industry respondents. Chapters 3 to 6 address the comments received to the consultation questions and outline the TSOs' considerations and final recommendations on these topics.

These chapters address the TSOs recommendations following the review of industry feedback on 'Future system needs' (Chapter 3), 'Volume Forecasting Methodology' (Chapter 4), 'Implicit Bundling' (Chapter 5), with additional considerations on issues raised by industry participants in their submitted responses outlined in Chapter 6. Chapter 7 outlines briefly the next steps in the delivery and implementation of the recommended methodology. Worked examples of the recommended approach to implicit bundling are outlined in Appendix A.

2. Consultation Overview

2.1. Responses to the Consultation

The DASSA VFM consultation paper closed for comments on 15th November 2024. In total, 13 non-confidential responses were received to the consultation, from the following stakeholders:

- Bord Gáis Energy
- Bord Na Mona
- Demand Response Association of Ireland (DRAI)
- Electricity Association or Ireland (EAI)
- Energia
- EP UK Investments
- ESB Generation
- ESB Networks
- Hanwha Energy Corporation Limited
- Mutual Energy
- RWE Renewables Ltd
- Wind Energy Ireland
- SSE

Note that all non-confidential responses have been published together with this recommendations paper.

2.2. General Consultation Feedback

The responses received to the Consultation are quite detailed and the TSOs appreciate the time and effort industry participants have committed to reviewing the proposals and providing very helpful feedback. We have assessed the responses and have provided further information in this paper where possible to aid clarification on some issues.

In addition to the questions asked in the Consultation paper many respondents provided feedback on wider aspects of the DASSA and FASS arrangements. These are valuable to capture, and we have addressed these in Chapter 6 as part of our review of the responses provided to Question 5.

In general, the responses received to the consultation were mixed, with many requests for further consideration of future system developments and more detailed methodology development. There was support provided for the level of detailed consideration undertaken by the TSOs and the complexity of finding an appropriate balance between the uncertainty of reserve requirements at day ahead stage and providing a clear volume requirement to industry to prepare for DASSA and DAM bid submissions.

There was also broad support for the dimensioning of the required volume of reserves for POR, SOR, TOR1 and TOR2 to meet at least 100% of the RI, consideration of the publication of volume requirements for both static and dynamic and the need to ensure continual review of evolving system dynamics as part of the annual and weekly forecasting processes.

3. Review of Comments Received on Future System Needs

3.1. Summary of proposals

The TSOs refer to chapter 3 of the consultation paper for the full background and detail on their proposals with respect to System Needs for reserves.

On a high-level, the TSOs' proposals in the consultation paper are:

- By 10:00 each day, the TSOs will publish the required reserves volumes that will be procured in the DASSA on that day D-1 for the following day D. The TSOs will specify volume requirements for all upward and downward reserves products (FFR, POR, SOR, TOR1, TOR2, RR) separately and will specify for each product minimum volumes per jurisdiction and minimum volumes of dynamic response. For FFR, minimum volume requirements for category 1 (Full Activation Time (FAT) = 150 ms) and category 2 (150 ms < FAT ≤ 300 ms) will be specified. The required reserves volumes will be published for all transaction periods of the following day D.
- The required All Island reserve volumes for FFR, POR, SOR, TOR1, TOR2 and RR will be determined based on the system needs (e.g., aligning with the TSOs' operational policy on reserves) with the objectives of:
    - Maintaining frequency within 49.9 – 50.1 Hz range for 98% of time, as monitored and reported on annually in the All-Island Transmission Performance report. This means the system frequency will unlikely exceed the standard frequency range (49.8 to 50.2 Hz) more than 15,000 minutes/year (2.9% of minutes/year), as required by the SOGL and SAOA.
    - Mitigating large disturbances to avoid a maximum instantaneous frequency deviation larger than 1000 mHz from the nominal frequency of 50 Hz and a RoCoF larger than +/- 1 Hz/s, following the requirements in the TSOs' OSS, SAOA, LFCBOA, and the SOGL.
- To meet the first objective above, the TSOs will annually review the frequency quality trend of the previous five years and assess the need for adapting the minimum volume requirements for dynamic reserves.
- Currently, for POR and SOR the TSOs dimension reserve requirements to ensure that sufficient reserves to cover 75% of the loss of LSI are secured. To meet the second objective above in the future, and in accordance with the requirements in the SOGL, the TSOs propose that for DASSA the required downward and upward POR, SOR, TOR1, TOR2 and RR volumes shall be dimensioned to ensure sufficient reserves to secure against 100% of the RI for outfeed and infeed losses. The required reserves will consist of the following components:

- The TSOs consider that, at least initially, given the lack of foresight of day ahead and intra-day energy market outcomes, and in particular interconnector schedules, it will not be feasible to forecast the RIs (All Island or jurisdictional) with a reasonable accuracy before the DASSA takes place.
- In order to facilitate all possible market outcomes and in the advance of certainty of dedicated opportunities for the TSOs to procure reserve volumes after DASSA, the TSOs will take a prudent approach and assume that all system infeeds that could be in service on the next day D may feed in at their maximum capacity (i.e., RI will include the impact of the maximum LSI loss) during all

trading periods of the following day. Similarly, all system outfeeds that could be in service on the next day D may feed out at their maximum capacity (i.e., RI will include the impact of the maximum LSO loss). The RI will also need to account for potential consequential losses of e.g. trips of generation or reduction of demand from demand units (as seen from the grid) triggered by the same incident. Consequential losses are typically inadvertent (from a system perspective) and caused by e.g. lack of FRT capability of the concerned demand/generation. Box 1 below show the determination of the RIs in formulas.

Box 1: All Island Reference Incidents in formulas

The TSOs propose the following formula for determining the reference incident for infeed and outfeed losses, which align with the TSOs' OSS:

$$RII^{AI} = LSI^{AI} + CLI^{AI} \quad [1]$$

$$RIO^{AI} = LSO^{AI} + CLO^{AI} \quad [2]$$

In which:

$$RII^{AI} = All\ Island\ Reference\ Incident\ for\ loss\ of\ Infeeds$$

$$RIO^{AI} = All\ Island\ Reference\ Incident\ for\ loss\ of\ Outfeeds$$

$$CLI^{AI} = All\ Island\ Consequential\ Loss\ of\ Infeed$$

$$CLO^{AI} = All\ Island\ Consequential\ Loss\ of\ Outfeed$$

$$LSI^{AI} = \text{All Island } Largest\ Single\ Infeed$$

$$LSO^{AI} = \text{All Island } Largest\ Single\ Outfeed$$

- In addition, the TSOs consider it important to account for potential loss of reserve provision from the units setting the LSI and LSO, and will add a component to the DASSA reserve volume determination to cover this risk. Also, the TSOs need to consider in the DASSA reserve volume determination the potential unavailability of reserve providing units, for example, one or more reserve providing units becoming unavailable due to a forced outage or a transmission restriction/fault which limits the provision of their service.
- The All Island RI will then be determined separately for outfeed and infeed losses and will be the sum of the LSI or LSO and potential consequential losses. Note that the TSOs aim for minimising consequential losses, by proposing adequate technical requirements that prevent consequential losses. Note that system defence measures are not considered as consequential losses.
- In addition to the All Island RI, the TSOs define jurisdictional RIs for both IE and NI. These jurisdictional RIs are set by the imbalance in each jurisdiction after a system separation caused by a trip of both circuits of the existing N-S Interconnector. Consequently, the jurisdictional RIs are driven by the flow on the N-S interconnector. Also, the jurisdictional RIs will need to take into account consequential losses. Box 2 below shows the determination of the RIs in formulas. The need for jurisdictional RIs will be reviewed after the second N-S Interconnector will start operation.

Box 2: Jurisdictional (Island Split) Reference Incidents in formulas

SONI's OSS[26] stipulates that the system frequency and RoCoF shall stay within the specified limits, after a fault and tripping of the 275 kV N-S tie-line that runs between the two jurisdictions[27]. As this trip results in a system split into two synchronous areas, both areas need to mitigate the imbalance, which can be positive or negative, depending on the direction of the flow on the N-S

[26] SONI Operating Security Standards v1.pdf

[27] The North-South Tie-Line is a 275 kV double circuit. Both circuits are carried on the same overhead towers so is considered a credible contingency.

tie-line before the trip. The Island Split RIs for outfeed and infeed losses for both IE and NI are defined by the following formulas.

$$RIO_{NI} = Flow_{N \to S} + CLO^{NI} \quad [3]$$

$$RII_{NI} = Flow_{S \to N} + CLI^{NI} \quad [4]$$

$$RIO_{IE} = Flow_{S \to N} + CLO^{IE} \quad [5]$$

$$RII_{IE} = Flow_{N \to S} + CLI^{IE} \quad [6]$$

In which:

$$RII_{NI} = Reference\ Incident\ for\ loss\ of\ Infeeds\ to\ Northern\ Ireland$$

$$RIO_{NI} = Reference\ Incident\ for\ loss\ of\ Outfeeds\ from\ Northern\ Ireland$$

$$Flow_{N \to S} = Flow\ on\ North - South\ tie - line\ in\ direction\ North\ to\ South$$

$$Flow_{S \to N} = Flow\ on\ South - North\ tie - line\ in\ direction\ South\ to\ North$$

Since the concept of RI presents a change compared to existing methodology which is based on LSI, the TSOs provide illustrative examples below (based on SOGL) to support/explain this concept.

Box 3: SOGL art. 153(2) on determination of the Reference Incident for FCR (POR and SOR)

SONI and EirGrid shall determine the required FCR (POR and SOR) capacity in accordance with SOGL Article 153(2), which provides specific requirements for each synchronous area. For the IE/NI synchronous area, *'the reserve capacity for FCR required for the synchronous area shall cover at least the reference incident.'* in which *'the size of the reference incident shall be [..] the largest imbalance that may result from an instantaneous change of active power such as that of a single power generating module, single demand facility, or single HVDC interconnector or from a tripping of an AC line, or it shall be the maximum instantaneous loss of active power consumption due to the tripping of one or two connection points. The reference incident shall be determined separately for positive and negative direction;'*

The TSOs consider that in this definition the interpretation of the individual components shall be:

- *'**Largest imbalance** that may result from an instantaneous change of active power':* The imbalance resulting from the event, which includes not only the direct loss, but also the consequential losses triggered by the same event.
- *'**Instantaneous change of active power** such as that of a single power generating module, single demand facility, or single HVDC interconnector or from a tripping of an AC line, or it shall be the maximum instantaneous loss of active power consumption due to the tripping of one or two connection points:* This shall be interpreted as the *credible events* that result in a sudden change in generation/demand.

Figure 2 provides an illustrative example of loss of outfeed followed by consequential loss. The *instantaneous change of active power.. '* concerns a trip (due to a fault) of a HVDC cable exporting 500 MW before the trip. The fault causes a voltage dip that propagates to various connections of LEU. This voltage dip instantaneously triggers the LEU's under voltage protections that reduce 200 MW of LEU demand (left-hand side of the figure). Accordingly, the *'size of the reference incident shall be the' 'largest imbalance'* triggered by this incident. This *'imbalance'* is the sum of *instantaneous change* of 500 MW + the *consequential loss* of 200 MW triggered by the under voltage protection = 700 MW (downward reserves).

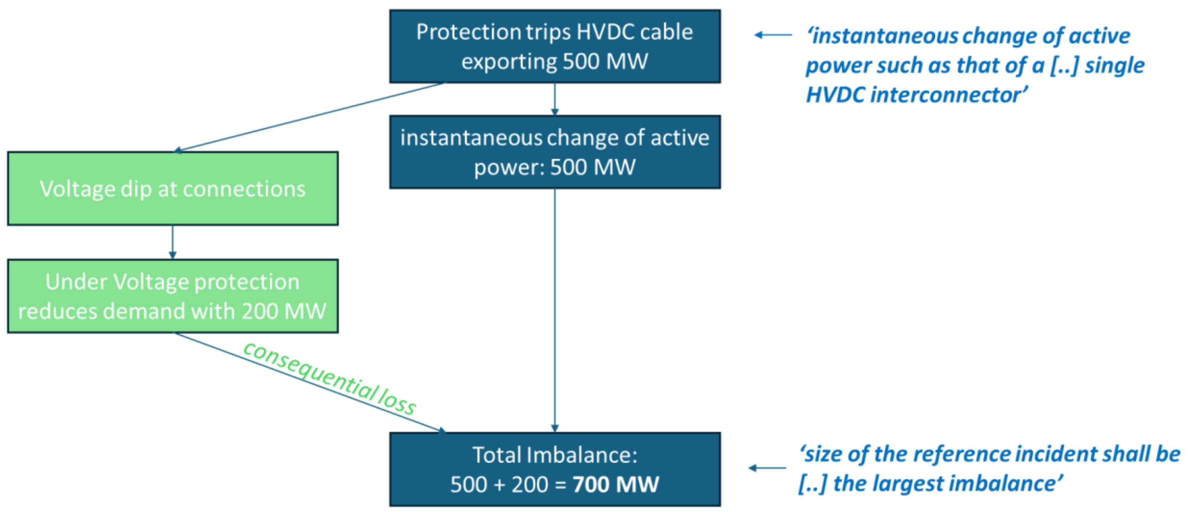


Figure 2: Example of determination of Reference Incident in accordance with SOGL art. 153(2). (note: example starts from a balanced position)

Figure 3 provides another illustrative example of loss of infeed followed by consequential loss. The *instantaneous change of active power..'* concerns a trip (due to a fault) of a HVDC cable importing 500 MW before the trip. The fault causes a voltage dip that propagates to various connections of DER. This voltage dip results in a reduction of 200 MW of DER, due to lack of FRT capability (left-hand side of the figure). Accordingly, the '*size of the reference incident shall be the*' '*largest imbalance*' triggered by this incident. This '*largest imbalance*' is the sum of *instantaneous change* of 500 MW + the *consequential loss* of 200 MW = 700 MW (upward reserves).

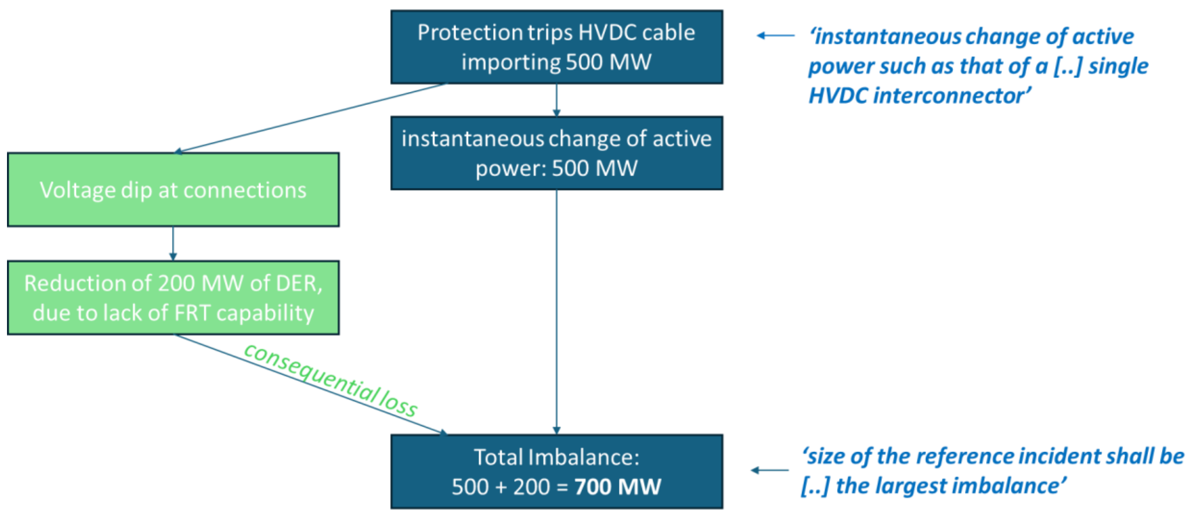


Figure 3: Example of determination of Reference Incident in accordance with SOGL art. 153(2). (note: example starts from a balanced position)

Box 4: SOGL art. 157(2)(d) on determination of the Reference Incident for FRR (TOR1 and TOR2)

Similar to what is explained in Box 33 for FCR (POR and SOR), article 157(2)(d) of SOGL determines for the dimensioning of FRR (TOR1 and TOR2) for the IE/NI LFC block that '*the TSOs of a LFC block shall determine the size of the reference incident which shall be the largest imbalance that may result from an instantaneous change of active power of a single power*

generating module, single demand facility, or single HVDC interconnector or from a tripping of an AC line within the LFC block;'.

3.2. Consultation Responses

The questions asked in relation to the system needs are summarised below.

Chapter 3 System Needs	**Question 1 Do you agree with our considerations in terms of future system requirements and yearly, weekly and day ahead volume forecasting and relevant publications. Are there any additional aspects you believe should be included? Please provide a detailed rationale in your response.** **Question 2 Do you agree with our proposal on the publication timing of the daily D-1 DASSA Volume Requirement? If you consider an alternative time should be considered, please provide a rationale in your response.**

The sections below provide an overview of the answers of respondents to the consultation, directly related to the specific topic of 'System needs'. The TSOs note that the respondents' answers to the questions also include comments that relate to other consultation questions. These comments have been addressed in the sections discussing the relevant question.

3.2.1. Question 1 Do you agree with our considerations in terms of future system requirements and yearly, weekly and day ahead volume forecasting and relevant publications. Are there any additional aspects you believe should be included?

The responses received to Question 1 indicated that four respondents support the TSOs' assessment on the system needs for a range of reserve products that (combined with other operational measures) manage both frequency regulation and mitigation of large disturbances. Three respondents were not in favour, where four others were mixed in their responses.

Respondents express their support for:

- Setting the required volume of reserves for POR, SOR, TOR 1 and TOR as at least 100% of the RI.
- Aligning the required volume of RR to at least the maximum volumes required for these services.
- Proposing considerations for system requirements and the associated yearly, weekly, and day-ahead volume forecasting publications.
- Focussing on both upward and downward reserves to manage under-frequency and over-frequency events is essential as IE and NI progress toward greater renewable integration.
- Differentiating between dynamic and static reserve responses, combined with a layered forecasting approach.

In addition to this, the respondents raised a number of issues and provided suggestions which are responded to below.

Frequency quality standards

One respondent notes that procurement to the minimum acceptable standard would result in under procurement. This respondent assumes that the system need considers '*the minimum acceptable standard as opposed to a higher standard currently being delivered, i.e.., the 1000mHz instantaneous frequency deviation vs the SO's stated aim to maintain frequency within a fifth of this variation (<100-200mHz)*'. Another respondent expresses similar concerns and considers it unclear if '*volumes procured in DASSA are to be based on meeting the 1000mHz range*' and asks if '*the SOs indicating a move to increased variation from the high-quality frequency experienced to date?*'

One respondent '*believes that the requirement to maintain the frequency within 49.9 and 50.1 Hz at least 98% of the time should be reviewed downwards to a more practical figure as interconnection levels increases, inertia levels decrease, and more variable generation increases.*'. This respondent refers to the requirement in the SOGL and SAOA requiring that the maximum number of minutes of frequency occurrences outside the standard frequency range (49.8 to 50.2 Hz) should be below 15,000. The respondent argues that by '*Maintaining the frequency within 49.9 – 50.1 Hz has maintained the maximum number of minutes outside this range to under 50 minutes in the last 10 years.*' And believes that '*the stringent dynamic volume requirements would be relaxed*'.

TSOs' response

The TSOs note that this proposal in no way tries to change the frequency quality standards or the TSOs' aim to comply with the frequency quality standards. The TSOs aim for meeting all frequency quality standards as listed in Table 4 and considering the requirements of the TSOs' OSS[28].

As explained in detail in section 3.1 of the consultation document, there is a difference between the frequency ranges referred to by the respondents: TSOs aim to keep the frequency deviation below ± 100 mHz range for *at least 98% of time, measured over one year*. In addition, at all times[29] the TSOs aim to avoid a *maximum instantaneous frequency deviation* of more than 1000 mHz.

On the respondent's suggestion that '*the requirement to maintain the frequency within 49.9 and 50.1 Hz at least 98% of the time should be reviewed downwards*' referring to the far less strict Frequency quality target parameters in SOGL, the TSOs refer to Article 5 of their approved SAOA, which stipulates that the TSOs '*do not interpret the frequency quality target parameter as a target to be achieved but will endeavour to minimise the number of minutes outside the standard frequency range to a value below this.*'. In practice, the TSOs report annually in the All-Island Transmission Performance report[30] on system frequency performance within a range of 49.9 to 50.1 Hz, in line with a requirement to ensure that the system frequency shall be within the 49.9 to 50.1 Hz range for more than 98% of time[31] measured over a year.

[28] Operating Security Standards (eirgrid.ie) and SONI Operating Security Standards v1.pdf

[29] For credible contingencies as mentioned in the TSOs' OSS.

[30] https://cms.eirgrid.ie/sites/default/files/publications/All-Island-Transmission-System-Performance-Report-2023.pdf

[31] https://cruie-live-96ca64acab2247eca8a850a7e54b-5b34f62.divio-media.com/documents/CRU20078-PR5-Regulatory-Framework-Incentives-and-Reporting.pdf

Table 4: Overview of frequency quality standards

	Parameter	Defined in
Standard frequency range	± 200 mHz	SAOA[32], based on SOGL[33]
Maximum instantaneous frequency deviation	± 200 mHz	SAOA, based on SOGL
Maximum steady-state frequency deviatio006E	500 mHz	SAOA, based on SOGL
Time to recover frequency	1 minute	SAOA, based on SOGL
Frequency recovery range	± 500 mHz	SAOA, based on SOGL
Time to restore frequency	15 minutes	SAOA, based on SOGL
Frequency restoration range	± 200 mHz	SAOA, based on SOGL
Alert state trigger time	10 minutes	SAOA, based on SOGL
Maximum number of minutes outside the standard frequency range	15 000 per year	SAOA, based on SOGL
RoCoF	± 1 Hz/s	TSOs' Grid Codes
System frequency within the 49.9 to 50.1 Hz range	> 98% of time	All-Island Transmission Performance report[34] PR5[35]

Assumptions related to or the impact of LOLE or reserve requirements

Several respondents are missing a reference to assumptions related to or the impact of LOLE or reserve requirements. One respondent *'would assume brings with it an assumed baseline volume of reserves always needed to support these metrics and ensuring that LOLE for instance is achieved for the new 3 hours in ROI.'*

Another respondent argues that *'reserves which are procured through the CRM, or through the DSO flexible product procurement, may influence the volume forecast and may have to be netted off.'*. This respondent seeks *'to clearly identify that the value determined in the Volume Forecast Methodology will be the value that is procured in the DASSA volume as part of the demand procurement. For transparency and confidence to the market, the DASSA should not replicate the CRM process whereby a capacity requirement value is determined but then a different demand curve is determined from this value in a non-transparent manner.'*

TSOs' response

The TSOs consider that the objective of the VFM is to determine the required volumes that need to be procured day-ahead to ensure sufficient levels of reserves in real-time to safeguard the security of supply of the system, or as one respondent says *'brings an assumed baseline volume of reserves'*. Conversely, CRM aims for ensuring the adequacy of the system, considering the long-term LOLE.

The TSOs recognise that the CRM includes incentives for real-time availability which are dependent on specified short-term reserve volumes. As per SEM decision[36], Administrative Scarcity Pricing (ASP) shall be

[32] S1-SAOA-for-the-Ireland-and-Northern-Ireland-Synchronous-area-29.09.2022-(post-Title-2-approval).pdf (eirgrid.ie)

[33] Regulation - 2017/1485 - EN - EUR-Lex (europa.eu)

[34] https://cms.eirgrid.ie/sites/default/files/publications/All-Island-Transmission-System-Performance-Report-2023.pdf

[35] https://cruie-live-96ca64acab2247eca8a850a7e54b-5b34f62.divio-media.com/documents/CRU20078-PR5-Regulatory-Framework-Incentives-and-Reporting.pdf

[36] WP-05: Institutional Arrangements (semcommittee.com)

included in the energy imbalance price, and will apply when there is insufficient available capacity to cover the combination of demand and the target level of *operating reserve*. Although the TSOs see the link, the TSOs consider that the impact on CRM and ASP are not within the scope of this consultation.

SOGL compliance

Several respondents argue that – when defining the VFM - SOGL requirements should be considered as *minimum* requirements. They suggest that it is more important that the amount of system services needed to support an electricity system with high SNSP penetration levels are procured, than to exactly fulfil the SOGL requirements. E.g. one respondent states that '*future requirements translate to the need to go beyond SOGL and EBGL compliance, in recognition that, Ireland is leading this challenge within the EU towards making best use of system services, in the absence of an advanced grid, on account of having amongst the highest levels of intermittent renewable generation in Europe.*'. Another respondent has a similar comment and suggest that '*SOGL requirements should not be deemed as the maximum standard that the RAs/TSOs seek to achieve, it should be seen as a baseline, with the TSOs building upon this to enable key internal targets, for example 95% SNSP levels.*'.

TSOs' response

The TSOs acknowledge the respondent's comment and confirm that the levels of reserves specified by the VFM account for uncertainties related to renewable forecasts, ex-ante market outcome, unavailability of reserve providers etc. The resulting volumes for POR, SOR, TOR1, TOR2 and RR should therefore be considered as the minimum volumes meeting SOGL's requirements for several potential scenarios, taking into account the specifics of the All-Island power system.

With respect to FFR, the TSOs note that the FFR product is not specified in SOGL but has been implemented (on top of the SOGL requirements) to support the increasing SNSP levels. Also in forecasting FFR volumes, the TSOs consider the above-mentioned uncertainties and determine volumes that would be sufficient for the potential All-Island scenarios.

The TSOs further note that the VFM does not only consider SOGL compliance, but also makes sure that national requirements are met, such as the requirements specified in the TSOs' Operating Security Standards[37] (OSS) and Grid Codes.

Box 5: Explanation of All Island vs Jurisdictional Reference Incidents

All Island vs Jurisdictional Reference Incidents

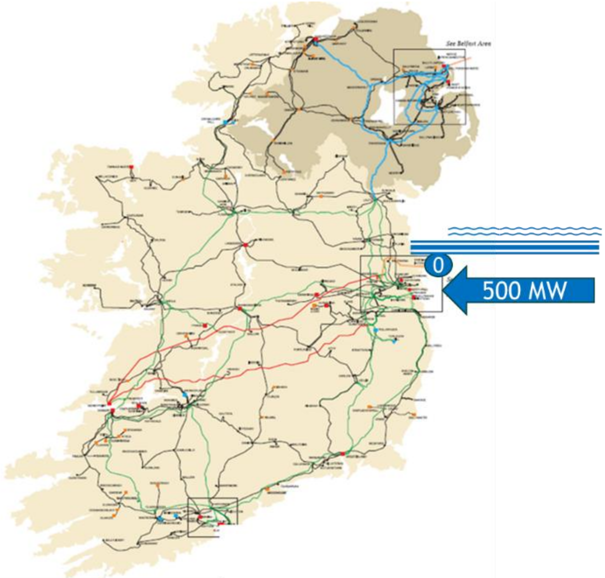
The TSOs need to consider two types of RI. Firstly, the All Island RI relate to a trip (e.g., caused by a fault) of the All Island LSI or LSO. Secondly, the jurisdictional RIs relate to a separation of the Irish and Northern Irish power systems, caused by a trip of both circuits of the existing N-S tie-line. Both RIs are explained below, based on illustrative examples.

All Island Reference Incident

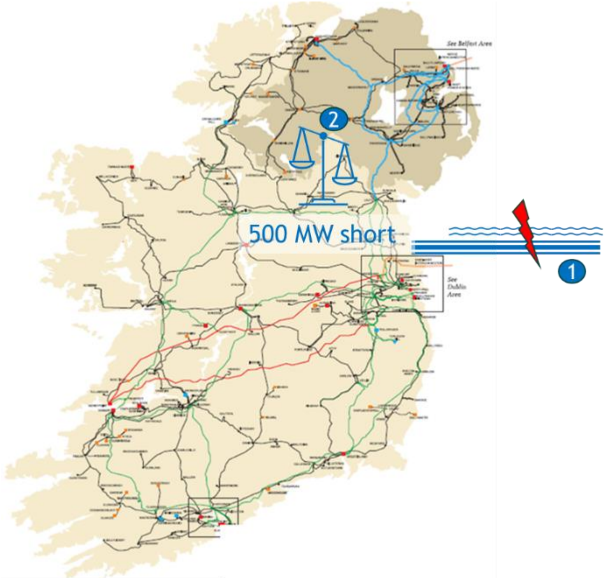
The All Island RI is the single event that results in the largest imbalance. This RI will then be determined separately for outfeed and infeed losses and will be the sum of the LSI or LSO and potential consequential losses.

The figures below provide an example for the reserves required for a trip of EWIC.

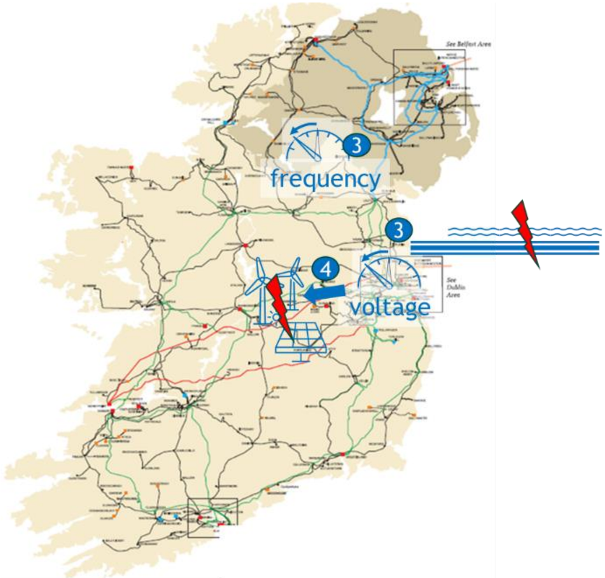
[37] Operating Security Standards (eirgrid.ie) and SONI Operating Security Standards v1.pdf



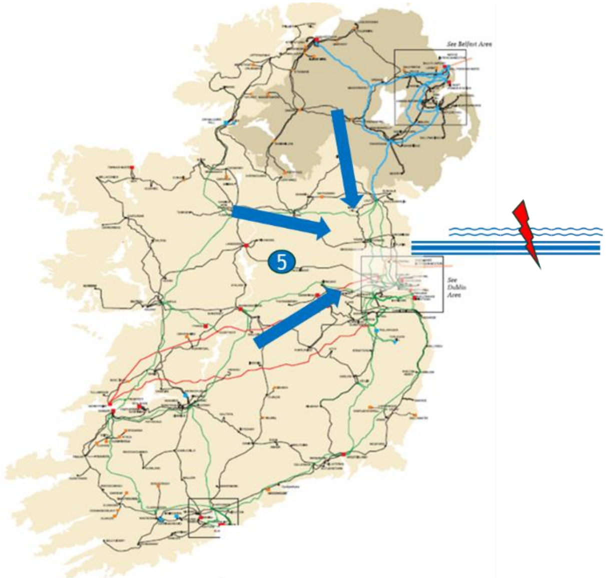
I. Pre-event: EWIC imports 500 MW to Ireland (0)



II. Event: EWIC trips (1) and the All Island system is 500 MW short (2)



III. Due to the EWIC trip, both Frequency (All Island) and Voltage around Dublin decrease (3). Voltage decrease causes 200 MW Consequential tripping of DER (4).



IV. Responding to the frequency decrease, 500 + 200 = 700 MW of reserves are activated, restoring the imblance and bringing back the frequency to 50 Hz.

700 MW of upward reserves is required to mitigate the imbalance after the RI: the size of the RI in upward direction is 700 MW.

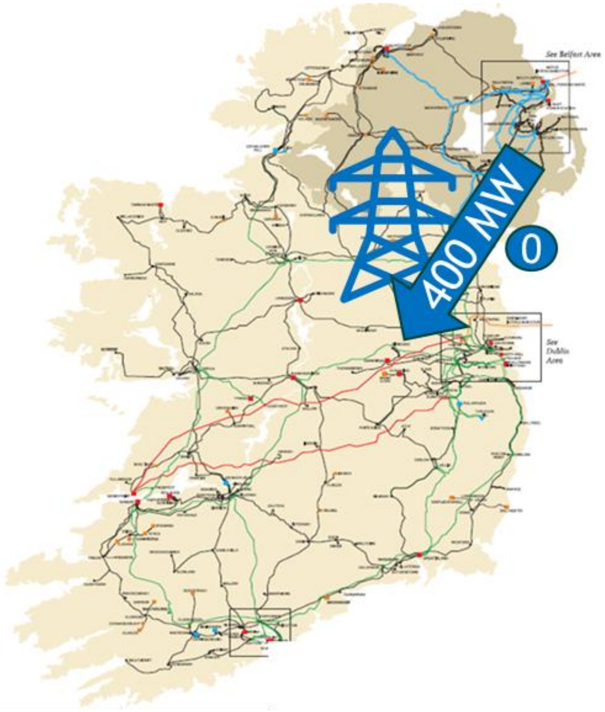
Similarly, the size of the RI in downward is determined.

Jurisdictional Reference Incident

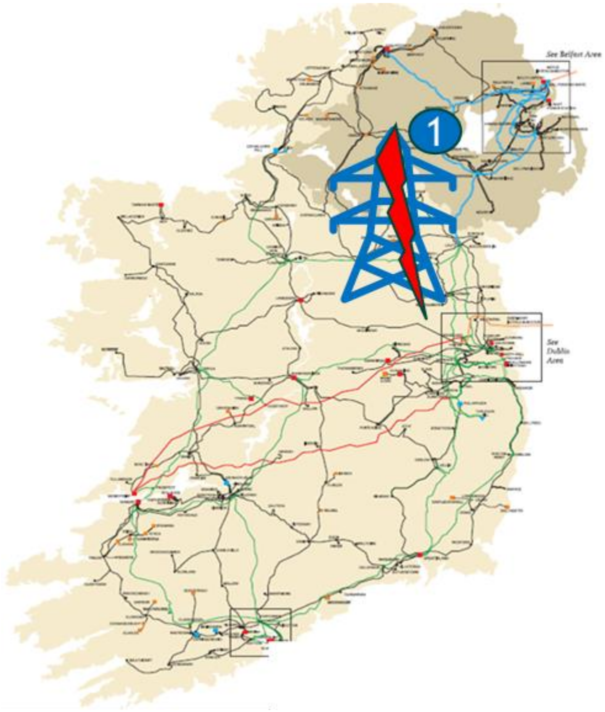
The jurisdictional RI implements the requirement in article 2.1/2.1.3 of SONI's OSS[38] : '2*.1 The transmission system shall be operated under prevailing system conditions so that for the secured event of a fault outage on the transmission system of any of the following: [..] 2.1.3 a double circuit overhead line on the 275 kV network.'* This article applies to a double circuit trip of the N-S interconnector, for which the TSOs should hold sufficient reserves.

[38] SONI Operating Security Standards v1.pdf

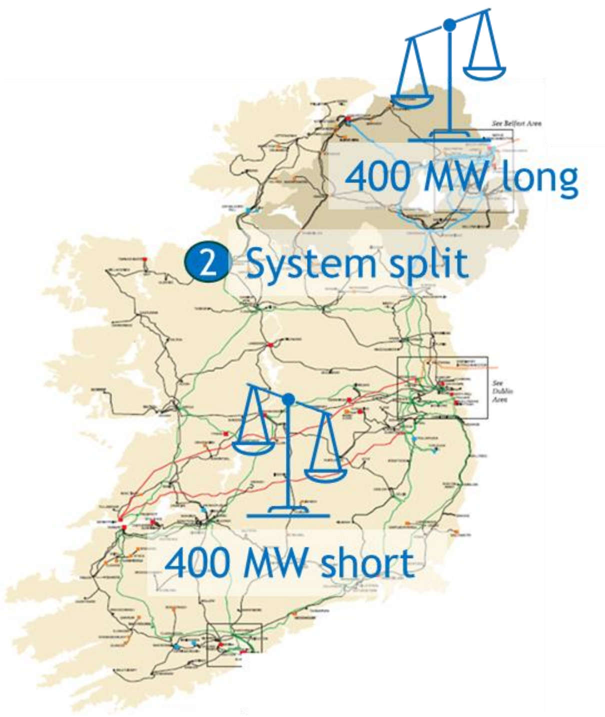
The figures below provide an example for the reserves required for a trip of the N-S interconnector.



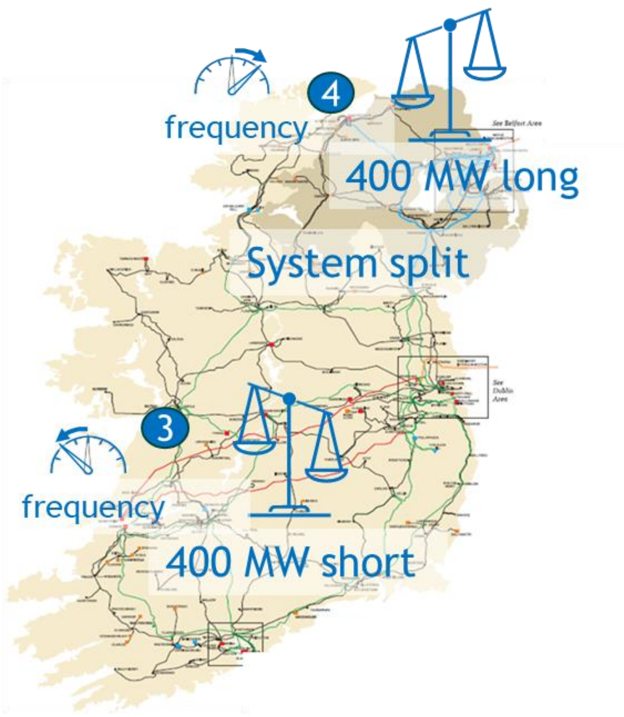
I. Pre-event: North to South flow 400 MW (0)



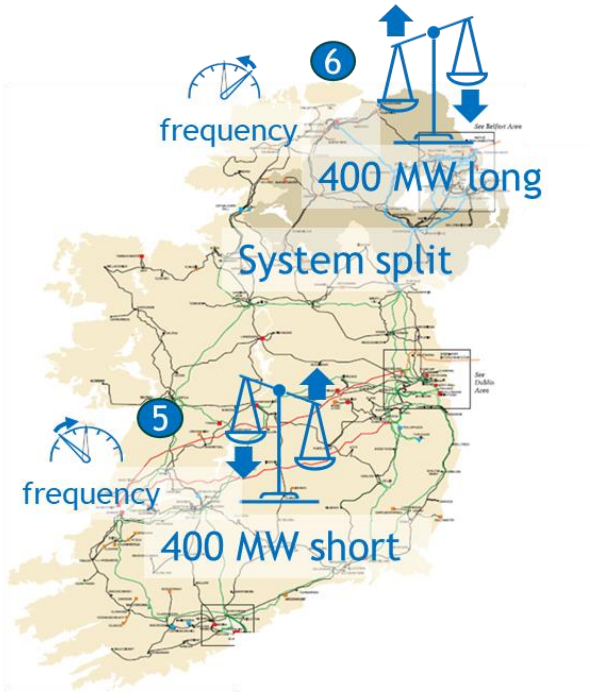
II. Event: Trip of both circuits of N-S Tie-line



III. Due to the trip, the system splits in two synchronous areas (2): IE is 400 MW short and NI is 400 MW long.

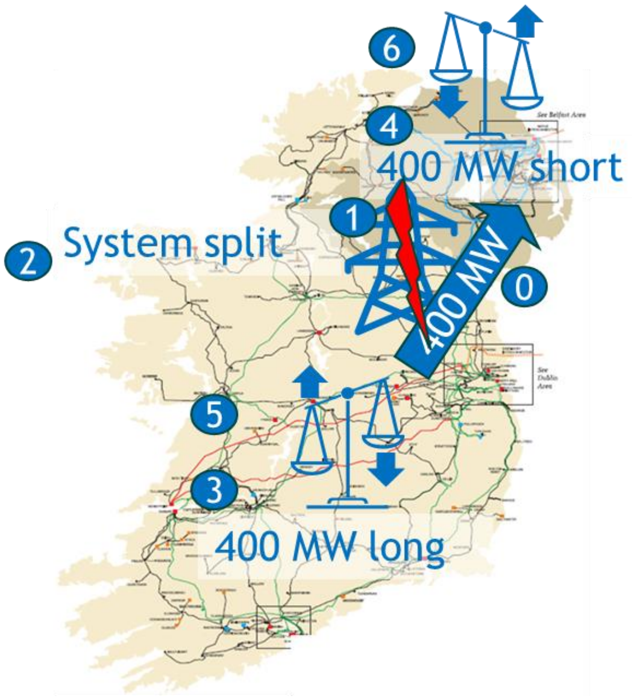


IV. Due to the system split and imbalance, system frequency decreases in Ireland (3) and increases in Northern Ireland (4)



V. Due to the frequency deviations, 400 MW of upward reserves are activated in IE and 400 MW of downward reserves in NI

The Reference incidents for the N→S flow:
IE: 400 MW + CL (Upward)
NI: 400 MW + CL (Downward)



VI. In the other direction: 400 MW of upward reserves are activated in NI and 400 MW of downward reserves in IE

The Reference incidents for the S→N flow:
NI: 400 MW + CL (Upward)
IE: 400 MW + CL (Downward)

Ireland and Northern Ireland Split / North South interconnector

One respondent argues that *'the fact that the North South interconnector is included also appears not to be given effective analysis but it needs to be made clear if this will not in fact be the LSI in future when it is delivered.'* Another respondent notes that *'presently a minimum quantity of reserves is specified as a requirement of each jurisdiction within ISEM. This paper did not however provide an overview of how those volumes are calculated currently and how the requirement for those jurisdiction specific volumes may alter in the future.'*

TSOs' response

The TSOs note that the current requirements for each jurisdiction within the SEM are mainly based on experience and engineering judgement. For the future, the proposed VFM determines reserve volumes for each jurisdiction based on detailed (dynamic) system simulations of the following credible contingency in SONI's OSS[39],[40]: A split of the synchronous area into two separate synchronous areas (Ireland and Northern Ireland) would happen after a fault and tripping of the 275 kV 'N-S Tie-line' that runs between the two jurisdictions[41]. The resulting two synchronous areas (Ireland and Northern Ireland) would instantaneously face an imbalance resulting from the interrupted 'N-S Tie-line' flow. As two separate synchronous systems

[39] SONI Operating Security Standards v1.pdf

[40] The SONI OSS is currently under review, any changes that may result from such a review, may drive changes to the volumes required as appropriate.

[41] The North-South Tie-Line is a 275 kV double circuit. Both circuits are carried on the same overhead towers so is considered a credible contingency.

without the potential to provide or receive support from each other, both systems would need to be individually capable of keeping the system frequency and RoCoF within the specified limits[42] after this sudden imbalance. For this, both jurisdictions require sufficient reserves.

When in future, the second N-S interconnector will be commissioned, both jurisdictions shall normally stay connected after a credible contingency according to the OSS. However, there are operational situations in which the risk of a system split may re-appear. For example, in case of a forced or unforced outage of the second N-S interconnector. For this reason, the TSOs consider that after delivery of the second N-S Interconnector, the jurisdictional reserve requirements will need to be reviewed by the TSOs.

Consideration of other multiple simultaneous failures

One respondent considers that *'The impact of multiple Interconnector failures also needs modelling, rather than just the singular LSI/LSO. The Island of Ireland needs to ensure Security of Supply at all costs given the isolation nature of our electricity system.'*.

Another respondent recommends to *'expand scenario modelling in the annual forecast to include extreme cases, such as prolonged low wind or solar periods, or unexpected high generation losses.* The respondents' rationale for this is that *'by including extreme scenario planning, the methodology would be better equipped to address high-impact, low-probability events.'* and could *'improve resilience by not only preparing reserve forecasts for the worst case but also potentially destabilize the scenarios.'*

TSOs' response

The TSOs note that 'multiple failures' are interpreted as simultaneous events with different causes. 'Multiple failures' shall not be confused with 'consequential losses' which are triggered by a main event and accordingly have a common cause. The TSOs consider that consequential losses need to be considered in determining the RI as discussed in section 3.3.2 of the consultation document.

On the consideration of multiple failures, the TSOs refer to their OSS (as referenced earlier in footnote 28) which define the standards on which operating procedures for the transmission system in Ireland and Northern Ireland shall be based. These include the contingencies after which the transmission system shall be operated within the criteria specified in the OSS. The OSS does not consider '*multiple Interconnector failures'* as a contingency after which the transmission system shall be operated within the criteria specified in the OSS.

Furthermore, the TSOs' proposal complies with requirements in article 153(2) and 157(2)(d) of SOGL which clearly refer to a single incident (see chapter 4 of the consultation document).

As a matter of fact, if the TSOs were to consider Multiple Interconnector failures this would increase required reserve volumes and procurement costs significantly above the (minimum) levels required when following the OSS, SOGL and Grid Code requirements.

Consideration of lower inertia

Several respondents consider that *'there is a need to 'model in' possible impacts of lower inertia.'*. Related to this, one other respondent requires further explanation on the TSOs' statement that *'in determining the FFR volumes, the levels of inertia on the system may also be important.'* and more specifically *'on how the level of FFR is dependent on inertia or why TSOs are not certain about the impacts of inertia on FFR volumes.'*

Another respondent suggests that the methodology could benefit from further refinement of the forecasting for system inertia. This respondent argues that *'As the share of inverter-based resources grows, system inertia will continue to decline, which could necessitate additional reserves, particularly FFR, to maintain stability. Including more frequent assessments of inertia levels as a forecasting input could help ensure that reserve requirements are appropriately scaled to actual system needs.'* This respondent additionally suggests that *'coordination with the DSO on available flexibility services and other DER contributions to reserves could enhance both accuracy and efficiency in volume forecasting.'*

TSOs' response

[42] Frequency deviation shall not exceed 1000 mHz, RoCoF shall not exceed 1 Hz/s.

The objective of FFR is to stop the frequency change before the frequency deviation is 1000 mHz (i.e. a Nadir ≥ 49.0 Hz and Zenith ≤ 51.0 Hz) and to help keep the RoCoF below 1 Hz/s. The main drivers for FFR volumes and speed are the RI and the inertia (see Figure 7 in section 3.3.3 of the consultation document): I.e. For the same RI, more and faster FFR is required if the inertia levels are lower. For a larger RI, the FRR requirements further increase.

The TSOs confirm that their proposed approach considers the impact of lower inertia: The detailed simulation studies which will be performed annually (see section 5.2.3 of the consultation document) take account of expected inertia levels. These will change due to future developments, including reducing Minimum Units Online (MUON) requirements and the increasing contribution to the inertia level by LCIS. With regard to DER contributions to reserves, the TSOs recognize that DER could play an increased role in the future, however, note that the proposed VFM is technology-agnostic.

Consideration of large-scale demand drops

Several respondents consider that *'the definition of LSI and LSO does not adequately consider the impacts of demand where large scale demand drops off the system.'*. One respondent adds that *'The lack of clear view of other possible and likely reference incidents under-represents the amount of reserves that could be needed in future. It is mentioned that other reference incidents could include demand related events for instance, but no attempt has been made to show how this could impact a future forecast which is important to be able to model what likely volume trends could be for reserves into the future, with reference to the 15+ commercial viability timeframe.'*

TSOs' response

The TSOs agree with the respondents that also large scale loss of demand could impact or determine the RI. For this, the TSOs' proposed methodology considers the following. Firstly, as demand customers may trip following the system conditions immediately after a fault of the LSO, the TSOs propose including 'consequential losses' in the formulas that determines the RIO (see section 3.3.2 of the consultation document). Secondly, the TSOs agree with the respondents that in future *´other reference incidents´* could set the RIs, which include *'large demand drops'*. For this reason, the TSOs' proposed methodology includes an annual analysis and update of potential reference incidents for the forthcoming 10 years (see section 5.3.2 of the consultation document). As shown in Table 12 of the consultation document, this could include, apart from a list of potential units, also '*other potential LSI/LSO*', including the example of a LEU that could set the reference incidents as shown in Table 12. The TSOs confirm that '*other potential LSI/LSO'* could also include *'large demand drops'* consisting of tripping of multiple small loads.

The TSOs further note that the VFM consultation paper sets out the methodology for volume forecasting. The actual volume forecasting will be first done in the course of 2026.

Inclusion of constraints and removal of FAM

One respondent argues that *'Additional reserves will be required to compensate for unavailability due to factors such as local constraints. The TSOs have not communicated how this has, or will be, included within the methodology, or how these additional reserves will feed into the daily volume requirement publications. Within the initial DASSA auction design consultation paper, it was proposed that only long-term run constraints would be included within the DASSA, with local constraints factored into the FAM. As the FAM is no longer being progressed, is not clear how the TSOs plan to determine the volumes required to cover service providers under constraints or how these volumes will be practically procured i.e. through the DASSA auction, Secondary Trading, TSOs participating in Secondary Trading, Balancing Market or Grid Code requirements. As requested within responses to previous consultations, there is a need to ensure that all DASSA proposals are aligned and provide a clear view of how each area of auction, and aligned consultation paper, interact and impact one another. This has been missing to date.'*

TSOs' response

The TSOs agree that local constraints may cause unavailability of reserves. For that reason, the TSOs included *'additional reserves for unavailability'* to the required reserve volumes (see section 3.3.2, 3.3.7, 5.3.2 and 5.4.2 of the consultation paper). These reserves cater for circumstances where, after the DASSA auction has concluded, reserve providing units may become unexpectedly unavailable or local constraints may limit the possibility to dispatch some reserve providing units, e.g., due to a forced outage or a transmission restriction/fault. Accordingly, actual available reserves may be lower than the reserves contracted in DASSA.

The TSOs consider that the methodology will need to evolve over time to include improvements based on real-life operational experience, evolving ex-ante market dynamics and improved forecasting tools. In addition, at the time of publication of the VFM consultation the SEMC had clarified that the TSO proposed FAM had not been approved, thereby signalling that the TSOs had to rely wholly on the DASSA procured volumes to ensure availability of reserve requirements in real time. There has since been intensive engagement between the regulatory authorities and the TSOs to explore potential alternative solutions to the FAM: the outcome of this joint assessment process is that the TSOs will develop and consult with industry on a Residual Availability Determination (RAD) in early 2025, with a SEMC decision required thereafter. There is therefore, no approved alternative FAM solution available at the time of development of this recommendation paper. More detail on the proposed RAD will be made available as part of the consultation in early 2025, however to briefly summarise here: the proposed RAD will be an auction where service providers place bids (up to a week in advance, tbc) to provide System Services *if they have residual availability net of other market obligations, including ex-ante energy positions and DASSA Orders*. The RAD auction will clear ex-post, and will take account of real-time system needs only. The RAD will only award payment to service providers that would be physically capable of delivering the services.

Consideration of lack of FRT capability

One respondent considers that the lack of FRT is not factored in.

TSOs' response

This may be a misunderstanding since the lack of FRT capability is indeed factored in. The TSOs clarify that the formulas to determine the RIs include consequential losses. These consequential losses are mainly included to factor in the lack of FRT capability (see section 3.3.2 of the consultation document).

Consideration of real-time variability, particularly in wind and solar generation

One respondent *'observes that the volume forecasting relies on historical and expected conditions but may not fully account for real-time variability, particularly in wind and solar generation.'* and suggests *'Incorporating real-time data feeds into volume forecasting models could improve the precision of predictions. Fully automated robust control systems that adjust reserve volumes based on up-to the-minute data from RES, interconnectors, and demand response could reduce the gap between forecasted and actual reserve needs, minimizing the risk of over- or under-procurement. Include feedback mechanisms for market participants on forecast accuracy and actual reserve requirements could build confidence and allow stakeholders to adapt to forecast patterns. Regular publications of forecast accuracy metrics (e.g., percentage accuracy in reserve forecasts) could promote continuous improvement in forecast methodologies.'*

TSOs' response

The TSOs welcome this suggestion and confirm that there is a continuous effort to increase the (day-ahead) forecast accuracy. Nevertheless, the TSOs consider that accurately forecasting of the LSI and LSO day-ahead (before DASSA) is more complex considering that potential LSIs/LSOs (e.g. HVDC interconnectors, N-S tie-line) are not only driven by RES as the figures in section 3.4.2 of the consultation document illustrate. Hence, there is not a clear correlation between RES (and their forecast) and the LSI/LSO. The TSOs note that they are working on day-ahead prediction tools of LSI, LSO, N-S interconnector flow and inertia levels.

Consideration of increased role of distributed energy resources (DERs) and flexibility services managed at the distribution level

Several respondents note that the methodology does not include '*considerations around the increased role of distributed energy resources (DERs) and flexibility services managed at the distribution level as per the guidelines in the Network code on Demand Response*', '*or how these will impact outputs*'. The respondents consider that *'DERs are set to become a significant component of the system and should be factored into both short-term and long-term forecasting.'*. Other respondents suggest considering '*the* *interaction of this forecast with: (1) demand flexibility requirements (e.g. NEDs) and (2) the degree of dispatchable demand volumes on the distribution system is also not included. The inclusion of such demand would lend a fuller detail on the volumes required to be procured for system stability and resilience.*

The respondents further note that '*more granular real-time data on DER capacity, availability, and potential impacts on reserves will be critical.'* And that '*A coordinated approach between the DSO and the TSO for data sharing and forecasting could enhance accuracy, particularly in addressing local constraints that may affect reserve availability.'*

One respondent considers that *'The TSOs have provided no clarity on how the Distribution System Operators (DSO) flexibility service procurements processes are included within this methodology. The consultations states that further work is required on the interactions with these services and service providers, providing little confidence that the TSOs are taking a whole market approach when developing this consultation, and leaving industry with key information gaps when assessing proposals. By excluding these from this methodology, there is a substantial risk that the methodology 1) results in under- or over-procurement of Reserves, 2) further consultation is required once the interactions are understood and 3) service providers make commercial decisions based upon an inaccurate methodology which results in lost investor confidence in the process, detrimentally impacting the TSOs ability to ensure an economic transition to Net Zero.'*

TSOs' response

The TSOs acknowledge the comments and stress that they welcome the increased role of DERs and flexibility services managed at the distribution level. The TSOs note though that the scope of the VFM paper are the methodologies for determining the reserve volumes for meeting two objectives: both for keeping the frequency continuously within the 49.9-50.1 Hz range and for mitigating disturbances. The TSOs would like to clarify that the proposed methodologies for meeting both objectives take into account DER and flexibility services.

Firstly, referring to sections 3.2 and 5.3.1 of the consultation paper, the minimum dynamic reserves for keeping the frequency continuously within the 49.9-50.1 Hz range will consider the historical frequency quality trend which will implicitly capture the changes induced by increased DER and flexibility services. In addition, future developments will be considered in the annual 10 years forecast, which will also include increased DER and flexibility services.

Secondly, the TSOs note that a single DER or flexibility provider will not constitute a LSI or LSO. However, a large group of units DER or flexibility provider may potentially impact the RI if they trip all at the same time as a consequential loss to another incident. The TSOs therefore included the factor consequential loss in the formulas for the RIs in section 3.3.

The TSOs note that they agreed with the DSOs on the high-level principles of the Future TSO-DSO Operating Model and are currently working with both ESB Networks and NIE Networks on developing detailed design of Future TSO-DSO Operating Model[43] as part of the TSO-DSO Joint System Operator Programmes of work. The detailed design will consider the enduring high-level model for managing TSO-DSO interactions related to the provision of System Services from distribution connected service providers, including management of limitations on service provision (e.g., through an operating envelope). Note also that the TSOs (and DSOs) plan to engage with relevant stakeholders including industry and RAs as part of the Future Operating Model.

Consideration of Dispatch down

Several respondents mention the currently increasing levels of dispatch down and the *'clear need to continue to increase the SNSP limit*'. It is argued that *'High levels of Dispatch down can be offset by higher volumes of system services. The Investor signal is extremely important such that whatever mechanism is developed does not restrict the supply/provision of required volumes of system services, especially given trending significant increases in dispatch down levels.'*. Some of these respondents argue

[43] TSO/DSO Joint System Operator Programme (eirgrid.ie), Appendix-2-Independent-Expert.pdf (soni.ltd.uk)

that '*Inaccurate forecast volume methodology that underestimates the future need should not be the reason for failing to increase the SNSP limit in the future. It is vital that we continue to build upon the successful DS3 framework and not create a hiatus in investment through lower than needed system service volume forecasts.*'

TSOs' response

The TSOs note that the proposed VFM aims to determine the required volumes of reserves to keep the frequency and RoCoF within their defined limits (see chapter 3 of the consultation document). The starting points of the methodology are the expected system conditions, including the minimum level of inertia in the system, SNSP level etc, which are defined through evolving operational policy in e.g. the Operational Policy Roadmap[44]. Accordingly, the VFM determines the required volumes of reserves considering the inertia levels resulting from increasing SNSP (lower level of conventional units), but also from e.g. the introduction of LCIS. The TSOs therefore conclude that although it is not the objective of this VFM to reduce Dispatch Down, the VFM contributes to enabling increasing SNSP levels in the system while keeping the system secure.

Replacement Reserves

One respondent '*was unable to determine a methodology by which the quantity of Replacement Reserves could be calculated. Depending on the outcome of the new bundling workstream, there may be circumstances where a single unit is providing a suite of reserve products.*' This respondent '*had expected for this potential to influence the required amount of replacement reserve, as otherwise the failure of a large unit may have knock on consequences for different reserve products in different time periods.*'

TSOs' response

The TSOs agree with the respondent that the consultation document does not explicitly include the methodology on determining the volumes for RR. The TSOs therefore try to make the implicit reasoning in the paper explicit: In section 3.3.5 of the consultation paper, the TSOs conclude that the volumes required for (upward and downward) RR need to be at least the maximum of the volumes required for POR, SOR, TOR1 and TOR2. As section 5.3.2 of the consultation paper state that the volumes required for POR, SOR, TOR1 and TOR2 will be set equal to 100% of the RI (as proposed in section 3.3.4. of the consultation paper), it can be deducted from the methodology that the volumes required for (upward and downward) RR need to be at least the to 100% of the RI.

Referring to section 4.5 of the consultation paper, this proposal is in line with Article 160(3) in SOGL[45] which requires at a minimum that for '*IE/NI synchronous areas there shall be sufficient positive reserve capacity on RR to restore the required amount of positive FCR and positive FRR*' and '*there shall be sufficient negative reserve capacity on RR to restore the required amount of negative FCR and negative FRR*'. Considering that in the IE/NI FCR (POR and SOR) is released by FRR (TOR1 and TOR2), RR shall effectively restore FRR. Accordingly, the minimum required RR volume shall not be lower than the FRR volumes.

Use of 2025 scenario for DASSA

One respondent comments that '*No information has been provided on the input data, assumptions, sensitivities or overarching methodology used to develop the DASSA scenarios or why these scenarios only consider system need out to 2025. The TSOs have substantial experience in long-term scenario development through the TES process, therefore it is not clear why the TSOs are waiting until the implementation of the DASSA to undertake this analysis and present this information to industry.*'

Another respondent comments that '*the timeframe for modelling versus actual future system services need is confusing. The basis of the modelling does not show that the TSOs understand the future need necessary for the SEM as it progresses with a changing fuel mix, with different dispatch approaches (scheduling and dispatch delivery, Celtic go-live, emissions targets driving decarbonisation, offshore wind) and with increased SNSP. The starting point for the original DS3 is 40% SNSP which is now grossly*

[44] TSOs further refer to the Operational Policy Roadmap 2023-2030

[45] Article 2 of S2-LFC-Block-Operational-Agreement-for-Ireland-and-Northern-Ireland-29.09.2022.pdf (eirgrid.ie)

underestimated. The TSO separately is reviewing a Grid Code requirement for fault ride through obligations for all demand facilities, but at the same time, has depressed DS3 tariffs on the basis of oversupply of system services (but still based on a 40% SNSP tari$ calculation). The forecast in this paper does not consider these factors fully and does not model some of these sufficiently.'

TSOs' response

The TSOs acknowledge this comment and consider that the results taken from system needs for 2025 have been provided to illustrate the *methodology* for reserve volume forecasting, rather than to provide a view on the potential forecast of the long-term need for reserve volumes. The actual volume forecasting will be performed in the course of 2026.

Consideration of interconnector forecast

One respondent notes that *'it appears the interconnector forecast error is included in the calculation of reserve volumes, however interconnectors are also one of the reference incidents that system services need to mitigate. It is not clear how interconnectors will be treated and why they are in the forecast if they are also the cause for reserve service need.'*

TSOs' response

Considering their size and the related impact of a trip, it is expected that in a significant share of time, interconnectors may determine the RIs. As the DASSA volume is determined well before the interconnector schedules are firm, there is an uncertainty though on the flow on each interconnector. Consequently, as discussed in section 3.4.2 of the consultation document, the TSOs conclude that, at day-ahead, they should seek to procure reserve volumes to facilitate all potential all-island and jurisdictional infeeds and outfeeds that could result from market outcomes. Hence reserve should be procured to ensure that all interconnectors could be scheduled on either full import or full export.

At the same time – as correctly noted by the respondent - HVDC interconnectors could also provide reserves. As noted in section in section 3.3.6, the TSOs need to take into account the potential provision of reserves from a unit that may set one of the RIs as reserve capacity provided by an RI setting unit will also be lost if this RI takes place, e.g. an Interconnector. As noted in section 5.5.2, the methodology takes into account the potential reserve loss from a LSI/LSO contributing unit for the situation that RI takes place.

Weekly Forecast

One respondent notes *'that the current forecast - typically published on a Friday – covers the upcoming calendar week (Monday - Sunday). At the time the forecast is published therefore, Monday is 3 days away, while the following Sunday is 10 days away, implying that the certainty with which Monday is forecast is far higher than the certainty attached to Sunday's forecast.'*. The respondent *'wondered whether it might be possible to provide a weekly forecast on either a rolling basis, published either daily or every second day. The advantage of such an arrangement would be to ensure that a particular day of the week isn't always subject to an information lag.'*

TSOs' response

The TSOs clarify that the most important input for the determination of the minimum reserve volumes for mitigating contingencies is the RI and the system inertia, which are largely driven by market outcomes. As these are highly unpredictable on a week-ahead basis, there is limited new information that can be used to update the tables resulting from the annual process (see section 5.4.2 of the consultation paper). Accordingly, the weekly process is only to use up to date information to adapt the likely required volumes as outlined in the annual report, if required. The results will be included in the Weekly Constraint Update and shall be applied as a guideline in the daily processes to determine the volumes to be procured in the DASSA.

Volatility of Volume Forecast

One respondent wants to understand how (likely) volume requirements – for individual products - are likely to change day-ahead, compared to the week-ahead.

TSOs' response

As discussed in section 5.5 of the consultation paper, for determining the reserves on a daily basis, the TSOs will normally rely on the information from the weekly process:

- For the minimum level of reserves required for maintaining system frequency within 49.9 – 50.1 Hz range, the TSOs will normally apply the information from the weekly process, unless observed frequency quality requires the TSOs to procure additional volumes of dynamic reserves.
- The volumes of reserves required for mitigating large disturbances need to be defined before the results of the ex-ante markets are known. As the results of the ex-ante markets drive the LSI and LSO the TSOs will take a prudent approach and assume that all system infeeds that could be in service on the next day D may feed in at their maximum capacity and all system outfeeds that could be in service on the next day D may feed out at their maximum capacity (see section 3.4.2 of the consultation paper). Based on these LSI and LSO, the TSOs determine the required reserves by applying the parameters specified in the weekly constraint update. Consequently, the TSOs do not expect high volatility in the volume forecast for the reserve products. However, updates in the reference incident value may be needed if e.g. (one of the) a reference incident is changed because of e.g. a forced or unforced outage, changed constraints on tie-line flow or abnormal events that increase risk such as a major storm or solar eclipse.

Future developments

Several respondents consider it unclear from the consultation paper if the *'assumption that what has occurred in the past will be an appropriate indication for what is needed in the future.'*. These respondents consider that *'Ideally, the consultation paper would have provided greater detail into what the system conditions will be like in the future and how this would identify the required forecast volume methodology.'*. They argue that *'volume assessments need to be made based on future requirements rather than potentially based on extrapolation from the past.'*

One respondent considers that more consideration could be given to the impact of certain **future developments**, including the go-live of the Celtic Interconnector, considering

- the impact of day-ahead coupling with the European market.
- Celtic being a key driver in setting volume needs due to its size.

Another respondent assumes that *'the TSOs' approach to assessing future system requirements may be insufficient'*. This respondent considers that *'there is substantial risk that an enduring methodology is being developed which is based on existing and historic reserve needs, not on future system and policy requirements (i.e. SNSP levels of 90%).'* The respondent considers that *'The consultation provides little qualitative or quantitative assessment of how the future power mix, and wider system service procurement tools, will impact the TSOs assessment of volumes needed within the DASSA. It may be that the future system service needs do not change, but that it is the providers of the system service that changes. However. this has not been clearly identified in the consultation paper'*.

One respondent argues that this *'reduces investor confidence and creates uncertainty that the frameworks being proposed will 1) deliver what the system requires in the future, 2) take a holistic approach to include wider procurement tools and 3) support in enabling Government targets for Net Zero. Considering this, ESB GT has set out areas which require further information and assessment below, as per the Chapters within the consultation paper.'*

Another respondent comments that *'The approach to this forecasting is similar to the approach in GB. However, the level of detail and granularity in the forecasting modelling and reporting in GB is far more defined, detailed and robust than what is proposed here. There is no coherence in this proposed forecasting approach compared to SOEF, GCS and TES ambitions and forecasts. There is also not a read across to resource adequacy, loss of load and demand loss. We know how much large energy demand will enter the island most likely, and that has been quantified by the TSO before, but the impact of this in reference incidents etc, is not considered or modelled to inform the future volumes forecast.'*

TSOs' response

The TSOs note that the VFM consultation paper sets out the *methodology* for volume forecasting. The actual volume forecasting will be first done in the course of 2026, taking future developments and uncertainties into account, including the developments mentioned by the respondents. As suggested by the respondents and discussed in section 5.3.2 of the consultation document, the TSOs propose to utilise information and assessments from other established processes (e.g. Generation Capacity Statements[46], Ten Year Transmission Forecast statements and the Transmission Development Plans), operational knowledge and expert engineering judgement.

3.2.2. Question 2 Do you agree with our proposal on the publication timing of the daily D-1 DASSA Volume Requirement?

The responses received to Question 2 indicated that while five respondents indicated support for the TSOs' assessment, recommendation for the timing of the DASSA reserve volume requirements at the day ahead stage noting that a balance needed to be struck between early indication of DASSA volumes before the day ahead wholesale energy market (DAM) gate closure time there is clarity available on interconnector and tie-line flows and potentially later timing with slightly more accurate information. Six respondents had some concerns or suggested alternative timings. One respondent did not comment on the proposal.

Several respondents included statements that there is still uncertainty and further development required across a number of elements of DASSA design and other Future Power Market aspects and as such they wish to reserve the right to change their support for the 10am publication timing. The alternative timings proposed varied as detailed below;

Earlier publication time suggested

Three responses suggested earlier times of 09.30 and 09.00 citing the volume of other market/trading considerations that market participants have to manage in the lead up to the DAM at 10am, e.g.; '*Trading activity is particularly intense pre-the 11am cut off for Day Ahead trades, which is likely to entail that trading teams have little ability to incorporate the forecast of DASSA volumes into their Day Ahead positions in a meaningful way. (Our) suggestion would be that the forecast could be published at least an hour earlier, e.g. 9am.*

Later publication time suggested

One respondent proposed '*An alternative timing, however, could be considered as late as possible before wholesale market gate closure to provide a slightly longer window for incorporating updated weather forecasts, which heavily impact renewable generation forecasts. Given Ireland's high dependence on wind generation, a later publication could improve forecasting accuracy and lead to better-informed auction outcomes, although this would need to be weighed against the impact on participant preparation times for entering wholesale market orders.*'

Additional updated publication

One respondent also suggested that the TSOs consider an additional updated publication at 12.00 to provide additional updated information '*Given the challenge in balancing the accuracy of DASSA volume forecasts with the need for timely market information, providing frequent updates rather than a static document could be highly beneficial to market participants. Publishing the DASSA volume forecast earlier (at 9am) with perhaps an update published at say 12am may strike an effective balance, between availing of updated information (post DAM closure) whilst reducing the burden associated with producing these reports on the TSO.*'

TSOs' response

The proposed publication timing should assist industry participants to understand the volumes required and help inform their bidding considerations for both DASSA and the day ahead energy market. It is

[46] Note that in 2025 the TSOs will publish the All-Island Resource Adequacy Assessment which will replace the Generation Capacity statement, based on a methodology that was consulted on in 2024. The TSOs will utilise all available up-to-date information for the initial VFM forecasting in 2026.

important to note that the gate closure time for DASSA bid submissions is, as per the SEMC DASSA design decision, proposed as 15:30.

In relation to the suggested alternative times, the TSOs recognise that the 10:00 time may add additional considerations at a time of in-depth trading decision making and may make it more difficult for participants to assess their DASSA and energy market trade-offs. However, providing a forecast in advance of the current proposal of 10am is less practical considering the preparation and validation work the TSOs need to undertake to prepare the forecast.

In response to the proposals for later timing, we believe the response is suggesting that the publication window is moved to closer to the wholesale day-ahead energy market (DAM) gate closure time, essentially to a time somewhere between 10:00 and 11:00. For the reasons outlined by other market participants above we do not consider this would assist market participants in formulating both their DAM and DASSA bidding strategies.

In relation to the proposal for an additional updated publication at 12:00, the TSOs have considered this request to utilise DAM outcomes to provide greater clarity to industry and assist with secondary trading activity. It is important to note however that although the DAM market results will provide greater clarity on likely Celtic flows, there could be further cross border market flow impacts as a result of EU Intraday market trading, SEM/GB trading etc. Additionally, LSI/LSO values could also be impacted by forced outages that occur later than 10am. Until operational experience of coupled day-ahead market dynamics is established it is difficult to ascertain with any certainty what the level of improved understanding of LSI/LSO maybe be available post DAM market but pre intraday markets. However, the TSOs will prepare IT systems to enable the publication of updated forecasts after the DAM markets and before DASSA gate closure. Such additional forecasts will be subject to further considerations regarding the accuracy of forecasts after DAM but pre intra-day market outcomes, and the TSOs' ability to ensure sufficient reserve volumes after DASSA auction outcomes. Although the TSOs plan to having the capability available at DASSA go-live, for the initial DASSA go live our intention is to only publish a 10am DASSA Volume requirement.

Auction timing considerations in relation to the SEMC Decision on FAM removal

Several respondents also raised concerns regarding the removal of the FAM and the need to ensure unimpeded secondary trading access for renewable and storage assets to manage resource availability and DASSA order commitments. Respondents raised concerns that if future developments on secondary trading or FAM alternatives necessitate a change to the volume methodology then this should drive a re-examination of the volume publication timing.

'There is still a considerable amount of DASSA design decisions remaining before it is possible to say what liquidity may look like for market participants. However, with the current information available (no FAM, system service bids being a single submission at the DAM, no DASSA payment due to TSO movements etc.) it is difficult to see the market in DASSA being very liquid in operation. Service providers that can provide energy have to make a decision between bidding their energy, or within the static DASSA market. Therefore, the 10am timing is relatively difficult to comment on as we do not have clarity on the attractiveness of DASSA, and we do not have clarity on capacity withholding for the DASSA for some volumes that could otherwise be traded as energy.'

TSOs' response

At the time of publication of the VFM consultation the SEMC had clarified that the TSO proposed FAM had not been approved, thereby signalling that the TSOs had to rely wholly on the DASSA procured volumes to ensure availability of reserve requirements in real time. AS outlined in Section 3.2.1 the TSOs will consult with industry on the proposed alternative to FAM, the RAD, in early 2025, with a SEMC decision required thereafter.

While there is therefore, no clearly defined or approved alternative FAM solution available at the time of development of this recommendation paper, the TSOs acknowledge the difficulty facing industry participants in providing clear opinions on the proposals provided. However, as the intention of the RAD is to support the TSOs to manage 'gaps' left by any lapsed DASSA Orders and meet any additional reserve volume – above that procured in the DASSA - required to meet real-time system needs. The TSOs do not therefore recommend a change to the volume publication timing.

EBGL platform interactions

One response queried whether the TSOs should consider how EBGL balancing energy platforms information may interact with possible timings of the publication stating '*it is possible that the LSI/LSO are identified after the IDAs but there is still the possibility that movement on the interconnectors via the MARI platform could change the ex-ante view of the LSI/LSO*'.

TSOs' response

The TSOs have outlined the uncertainty regarding IC flows at the Day ahead stage, in advance of DAM market outcomes. Additionally the TSOs consider there will only be clarity on mFRR energy trading volumes (and only if there is available balancing capacity on the Celtic interconnector to enable the flows of such energy trading) following TSO/ MARI Balancing energy platform interactions. This includes the submission of TSO needs to the MARI platform and the outcomes of the MARI platform balancing energy trades and resultant IC flow changes. The timings for these processes are between T-12mins and T-8 mins, i.e. shortly before real time. Therefore, the TSOs believe that MARI platform interactions will not be able to provide additional information at the Day ahead stage in time to inform the DASSA volume publication on Day ahead IC flows. As outlined previously the TSOs will be developing increased capability in day ahead forecasting over the coming years, and once MARI is operational further consideration will be given to any potential implications for volume determination. We consider such additional considerations will be captured in the annual VFM review and update processes.

Requests for an API accessible format publication

Several respondents asked for the publication to be made accessible via machine readable format through an API, rather than via a static document. This would allow for automatic integration into participants' internal systems, allow for updates and ease of access for participants.

TSO response

The TSOs agree with this request and will aim to ensure that the Volume publication is accessible via an API and in an appropriate format.

3.3. TSOs' considerations

Considering the responses received to Questions 1 and 2 of the consultation paper, the TSOs have updated their recommendations as outlined above and these have been summarised in the Executive Summary chapter.

4. Recommendations on Volume Forecasting Methodology

4.1. Summary of proposal

The TSOs refer to chapter 5 of the consultation paper for the full background and detail on their proposals with respect to the VFM. On a high-level, the TSOs' proposals in the recommendation paper are:

- The TSOs proposals include Annual, Weekly and Daily Forecasting proposals, which will ultimately result in the publication of the required volumes to be procured in each DASSA auction at D-1.
- In response to the SEM Committee decisions[47] relating to a ten-year forecast, the TSOs have proposed a methodology that could enable the provision of an indicative forecast of potential future reserve volumes. While this will need to be formalised through the development of the system services code, the grid code review and the licencing and governance workstream, our proposals are that ten-year forecasts would be updated annually to provide an overview of indicative required reserve volumes, including the characteristics (e.g., FFR FAT, dynamic) and location (IE, NI). Such an overview should include a high-level review of the reserve requirements for the next 10 years, with consideration of anticipated changes in the system. We will work with the RAs to identify the mechanism(s) to enable this forecast within TSO workplans. RA approved funding arrangements will also be necessary and will be considered under the wider implementation of DASSA/FASS arrangements. The annual forecast is also proposed to include more detailed assessments for the next procurement year Y+1. Such detailed assessments will be supported by power system simulations which will also provide the necessary input to the subsequent weekly and daily volume determination methodologies.
- The annual assessments shall also determine - based on detailed simulations - the minimum shares of dynamic response and the minimum shares for total FFR and FFR categories 1 and 2, relative to the RI. For example, based on simulation results for 2025, the TSOs expect that the required volumes of FFR would be typically around 70% of the RI for All Island, 80% for IE and 100% for NI. However, considering that the required FFR depends on system inertia, the TSOs will evaluate inertia provision annually and may modify these requirements accordingly.
- On a weekly basis, the TSOs will review the applicability of the results of the annual assessments and publish the guidelines, and parameters to be used for the day-ahead volume determination. The TSOs will aim to align this publication with the Weekly Constraint Update.
- On a daily basis, the TSOs will utilise the information from the Weekly Forecast and update as required e.g. to account for new planned or forced outages, changing constraints on N-S tie-line flow, specific adverse weather situations e.g. storms, etc, enabling the publication of required DASSA volumes by 10:00 on D-1.
- The TSOs consider the VFM to be prudent given the uncertainties that exist at the day-ahead stage. Accordingly, the TSOs will aim to improve the accuracy of the reserve volumes forecasts over time and take steps to reduce the risk of consequential losses, noting that there may be challenges with implementation. Approaches under consideration include:
    - Development of day-ahead predictions of LSI, LSO, N-S tie-lie & interconnector flow and inertia levels. This may allow for more accurate day ahead volume forecasts and the possibility to differentiate the volume needs per trading interval.
    - Reducing the risk of consequential losses, and accordingly the RI, through the development of new performance standards and capabilities that generation sources and demand should comply with.

[47] System Services Future Arrangements High Level Design Decision Paper.pdf (semcommittee.com) and SEM-23-103 SSFA Phase III - Phased Implementation Roadmap - Decision Paper.pdf (semcommittee.com)

4.2. Consultation responses

The question we asked in relation to this section was:

Chapter 5 Volume Forecasting Methodology	**Question 3. Do you agree with our methodology as presented in this Chapter? Do you consider there are other aspects that need consideration or whether there are amendments to the methodology you would recommend? Please provide detailed recommendations and a rationale for such recommendations in your response.**

4.2.1. Question 3. Do you agree with our methodology as presented in this Chapter? Do you consider there are other aspects that need consideration or whether there are amendments to the methodology you would recommend?

The responses received to Question 3 indicated that two respondents indicated their support for the proposed methodology presented in Chapter 5 of the consultation paper. One respondent was not in favour, where eight others were mixed in their responses.

Respondents express their support for:

- At a high level, the proposed methodology is a prudent approach to determining the actual system service volume requirements.
- Welcome a ten-year forecast published on an annual basis.
- The definition of the RIs, including changes of active power from the LSI/LSO and the direct response of the power system to the incident, including the reduction of demand or tripping of generation as a result of a lack of fault ride-through capability
- the comprehensive approach, addressing the main drivers of reserve requirements and integrating both historical data and forecasted conditions into the forecasting process.
- Separately assessing the requirements for each reserve category - FFR, POR, and others.
- base assumptions as set out in 3.3.2 regarding the Reference Incidents appear well-justified as the foundation for the reserve procurement.

In addition to this, the respondents raised a number of issues and provided suggestions which are responded to below.

Use of historical trends

One respondent indicated that the approach proposed by the TSOs is not sufficient. '*(We do) not have confidence that the TSOs approach of using historical trends of system services is a prudent or enduring approach to forecasting the needs of a power system that will be largely based upon synchronous condensers, batteries and renewable technologies for energy and system service provision. Current processes may not be accurate due to*

1) TSO IT systems placing restrictions upon the trading of batteries and

2) is significantly supported by conventional generating assets.

These factors will not be in place in the future and therefore alternative futures must be considered, which is currently missing from this consultation. (We) believe that it is vital that the TSOs consider the feedback provided within this response and reflect these changes within the final methodology, for example utilising examples of future system scenarios (i.e. 2027 and 2030) and outline what DASSA will need to look like in a power system with 95% SNSP. This will provide the confidence, certainty and signals industry require to effectively participate within the DASSA

<u>TSOs' response</u>

The VFM consultation paper sets out the methodology for volume forecasting, and actual forecasting of the DASSA volume requirements will first take place in 2026. The use of historical trends as explained in the methodology is focused on observations of frequency quality aspects to inform the quantities of reserve volumes for frequency regulation purposes - which on an annual basis has to be undertaken based on observed operational data e.g. percentage of time frequency was observed within and outside the 49.9 – 50.1 Hz range. The methodology proposed also stated that the challenges of frequency regulation will increase, mainly for the following reasons:

- Reducing inertia availability
- More variable generation (particularly wind and solar generation) and demand,
- Increased levels of HVDC interconnection which may ramp at greater speeds than today.

Since the aggregated impact of all future developments is impossible to predict accurately, the TSOs continually monitor frequency quality and reserve the right to take action to quantify new reserve requirements to remedy significant deteriorating frequency quality more frequently than on an annual basis. The proposal remains to establish minimum volume requirements for reserves for frequency regulation purposes as part of the annual process, while reserving the right to take within year action to re-examine and address deteriorating frequency quality if this is necessary.

For clarity, the proposed methodology for determining reserve volumes for contingency (event driven) requirements will, as outlined in the consultation paper, consider both future potential reference incidents, and detailed system studies and simulations based on future scenarios to determine appropriate volumes of reserves to manage potential future events. The TSOs welcome the feedback provided and wish to reassure industry participants that the system studies will look at future scenarios in line with the TSOs Operational Policy Roadmap[48].

The TSOs agree that forecasting the needs of the power system will be challenging, and have committed to evolving forecasting and dispatching capabilities.

Changes expected in the years after DASSA go-live

One respondent considers that *'By introducing a three-stage process (yearly, weekly and daily publications), there is a risk that the TSOs develop suboptimal forecasts at Y-1, which require to be resolved within the weekly document, removing any confidence of the long-term signals presented to service providers. This risk is increased as the TSOs highlight that the methodology will adapt to changes expected in the years after DASSA go-live. Any expected changes should be included within the methodology now, not in future iterations. Whilst change is always possible in the future, it is critical that any framework that develops from this consultation is as futureproofed as possible rather than a process that may require extensive change in the near future, reducing transparency and increasing market participant risk.'*

TSOs' response

On the first risk addressed by the respondent, the TSOs clarify that the methodology will be largely based on detailed simulations which are performed in the annual process. The TSOs do not expect significant new information between the annual and weekly processes. Accordingly, weekly volume forecasts will typically rely on the results of the annual process which should give a good indication.

On the second risk, the TSOs clarify that many changes are expected in the All-Island power system in the coming years. As all developments impact each other in uncertain ways, it will be impossible to predict the combined impact of these changes with a reasonable accuracy, at this stage of developing this initial VFM. Consequently, setting out changes to the methodology that will only be implemented in future years, would ignore this complexity, and reduce the capability of the TSOs to integrate future operational experience with DASSA, which could result in suboptimal solutions. For that reason, the TSOs have proposed a methodology that will facilitate the go-live of DASSA auctions in 2026 and will need to and can adapt to the changes expected in the years after, based on the best insights on the impact of the changes in the system at that moment.

[48] Operational Policy Roadmap 2023-2030

RA incentives placed upon the TSOs

One respondent argues that *'Further information is required from the RAs on incentives being placed upon the TSOs to accurately and transparently publish DASSA volume requirements, alongside any audit measures that will be undertaken to assess the effectiveness of this forecasting.'* and explains the agreed approach in GB.

TSOs' response

The TSOs clarify that they aim for accurately and transparently reporting on the (DASSA) volume forecasts and continuously improving these volume forecasts. The TSOs consider that this response may further be addressed by the RAs.

Apply LCIS zones for locational requirements in volume forecasting

One respondent recommends to *'Retain LCIS zones as the primary solution for locational requirements in volume forecasting.'* And to *'focus on coordinating reserves in these zones and provide early confirmation that in future synthetic inertia (including from inverter base technologies including storage) will be eligible to participate in future LCIS procurement and ensure future assumptions are captured within the 10 year and 1 year ahead forecasts.'*. The respondent's rationale is that *'LCIS zones have already identified key locations across Ireland where low carbon inertia is needed, addressing locational constraints in terms of inertia needs'*.

TSOs' response

On the LCIS zones, the TSOs clarify that the locational requirements that informed the LCIS zones were not based on a locational need for specific contributions to the inertia level, but were mainly based on requirements for necessary short circuit level support in the defined zones[49].

The TSOs further note that locational requirements for reserves have been addressed in the TSOs' Product Review and Locational methodology consultation paper[50], recommendation paper[51] and SEMC's decision paper[52]. It was concluded that – at the moment - the only locational requirements for reserves are on a jurisdictional requirement. The TSOs consider that the DASSA must not be unnecessarily restricted. Therefore, the TSOs conclude that it would be undesirable to add locational requirements by introducing LCIS zones which are not required from a system need perspective.

Box 6: Explanation of difference between jurisdictional requirements and zones applied for e.g. LCIS

From an operational perspective, the TSOs consider;

- *Jurisdictional requirements* which are used for the minimum reserve requirements related to the very specific requirement stipulated by art. 2.1.3 in the SONI OSS; and
- *Zones* which are applied for specific system services with a local need.

We explain the difference below.

Zones

The distribution of system service requirements to zones is required for system needs with a largely locational character. For example, voltage control is a local issue which means that sufficient reactive power compensation (which is required for voltage control) needs to be available in each part of the system. Accordingly, system services related to reactive power require a zonal approach (this will be addressed in the upcoming consultation on non-reserve services).

[49] Information Session – LCIS Consultation on Requirements and Procurement approach

[50] FASS-DASSA-Consultation-Paper-May-2024-EirGrid.pdf (EirGrid), FASS-DASSA-Recommendations-Paper-September-2024-SONI.pdf (SONI)

[51] DASSA Product Review & Locational Methodology Recommendation Paper (EirGrid), DASSA Product Review & Locational Methodology Recommendation Paper (SONI)

[52] SEM-24-074 Product review and locational methodology paper.pdf (semcommittee.com)

Zones do not need to be considered for system wide services such as reserves and inertia, provision of which supports the entire power system, regardless of the location of the provider[53].

In the LCIS procurement process, which procures three types of support from contracted providers; inertia support, reactive power support and short circuit level (system strength) support, the TSOs have applied zonal requirements. It needs to be noted that these zones did not relate to need for distribution of inertia (which is a system wide service), but to address local needs for system strength support in the individual zones (i.e., zones of low system strength)[54].

Jurisdictional Requirements

FFR, POR, SOR, TOR1 and TOR2 try to maintain the frequency quality[55] , across the All-Island system which is in compliance with the requirements in SOGL. This means that FCR reserves (POR and SOR in Ireland and N. Ireland) are dimensioned for the entire synchronous area and FRR (TOR1 and TOR2) reserves for the entire LFC block. In the All-island system case, both the synchronous area and the LFC Block consist of both Ireland and Northern Ireland. Consequently, required POR, SOR, TOR1 and TOR2 volumes are to be determined on an All Island basis.

However, there is one specific event for which reserves need to cater for, as per the current requirement in SONI OSS (art. 2.1.3). This event is a fault and tripping of the only 275 kV 'tie-line' that runs between the two jurisdictions[56], the N-S tie-line. Such an event would result in the split of the All-Island system into Ireland and Northern Ireland operating as separate 'islanded' systems, hence there would be no electrical link between the two systems anymore. Moreover, both islanded systems would instantaneously face an imbalance as large as the flow on the N-S tie-line before the fault. To cater for these imbalances, both jurisdictions require sufficient reserves to manage such an incident (We refer to a detailed description of the sequence of events in Box 5). Hence, there is a minimum requirement for each jurisdiction, at least until the delivery of the second North South Interconnector. As this is a specific incident, this results in the so-called jurisdictional requirements, not to be confused with zones.

Incorporation of Short-Duration, High-Response Services

One respondent recommends to *'Place a stronger emphasis on short-duration, high-response services, such as synthetic inertia from BESS and fast frequency response (FFR)*. The respondent's rationale is that *'In a system with low inertia, fast-acting reserves are critical. By increasing the visibility and inclusion of synthetic inertia and short-duration response services, the methodology could better manage the system's inertia requirements as conventional generators retire.'*

TSOs' response

The TSOs note that the product definition (including duration, response) of reserve products has been addressed in the TSOs' Product Review and Locational methodology consultation paper, recommendation paper and SEMC's decision paper. It was concluded and proposed that faster FFR was required and SEMC decided accordingly. Inertia services are currently being reviewed by the TSOs, resulting in a consultation paper on non-reserve services that is expected to be published in April 2025.

Additional forecasting for extreme events

Two respondents indicated that the TSOs should consider an additional forecast focused on extreme weather events or high impact system incidents.

'Could be further strengthened by including provisions for contingency forecasting in light of potential extreme weather events or high-impact system incidents. Given that reserve requirements can fluctuate

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[53] Subject to grid capacity.

[54] Information Session – LCIS Consultation on Requirements and Procurement approach

[55] For the synchronous area (as per SOGL art. 127) and the FRCE quality of the LFC block (as per SOGL art. 128)

[56] The North-South Tie-Line is a 275 kV double circuit. Both circuits are carried on the same overhead towers so is considered a credible contingency.

significantly under adverse weather conditions, a mechanism for forecasting reserve needs under these conditions could help the TSO manage risk more effectively'

TSOs' response

While the TSOs appreciate the proposals provided and agree that potential extreme weather events or high impact system incidents can bring additional risk to system security we consider that the weekly and day ahead assessments that are proposed as part of the VFM should be able to adequately manage the considerations necessary for such extreme events (e.g. storms).

Consideration of future developments in reserves required for keeping the system frequency within the 49.9 – 50.1 Hz range for more than 98%

Several respondents express their concerns on the consideration of historical quality data as input for determining the reserves required for keeping the system frequency within the 49.9 – 50.1 Hz range for more than 98%. One respondent suggests that instead of the proposed approach (based on a rolling average historical data), the TSOs should utilise a *'vast degree of information' 'to inform an assessment of the impacts of the future energy mix of the SEM on system stability and security. These include connection applications, Tomorrow Energy Scenarios (TES) and the direction provided by Government of the technology mix required to obtain Net Zero.'*

Another respondent also *'notes the use of historical data to determine data ahead volumes and suggests, given the increasing penetration of renewables, and increasing operation of low carbon synchronous condensers, that consideration of future requirements is also considered to ensure the required levels of system services is procured.* They also state that *'Basing volumes on lower levels of SNSP from the last number of years may provide an inaccurate forecast with potential to delay the 2030 targets.'*

Another respondent notes *'Currently, the TSOs IT systems prevent batteries from undertaking energy arbitrage. This will not be the case in the future. Therefore, it is not clear if this availability can be relied on as system services transition from DS3 to DASSA where batteries are not incentivised to be a system service provider if they do not hold a DASSA contract.'* This respondent also suggests the importance of considering all emerging market changes that may impact bidding behaviour, including *'greater bidding flexibility to service providers, current expectations of the availability of service providers may not be reflective of the future'*.

TSOs' response

The TSOs agree with the respondents that information about future changes needs to be considered in the VFM for determination of the minimum reserve requirements for maintaining the system frequency within the 49.9 – 50.1 Hz range for at least 98% of time. The TSOs further consider that as the frequency quality is impacted by many system parameters that are not easy to predict, and because frequency quality typically only changes gradually over years, the TSOs also proposed applying trend analysis for forecasting the required minimum volumes of dynamic reserves.

In section 5.3.1 of the consultation document, the TSOs therefore state that the review and update of these reserve requirements is proposed to be based on two inputs:

A. Historical frequency quality, expressed in percentage of time that the system frequency is within the 49.9 – 50.1 Hz range.

B. Future developments that may impact frequency quality (as mentioned in section 3.2 of the consultation paper) or the available dynamic reserves in real-time.

Transparency of Volume Forecast

Several respondents require more detail and transparency around the individual components that make up the forecasts, and the forecasts for the individual DASSA products. One respondent considers that *'there is no means by which industry can utilise these components to build models for internal volume forecasting, as this data is held by the System Operators (particularly on consequential losses).'* Accordingly, this respondent suggests that *'it would be beneficial to publish additional information on how each element of the forecast volume methodology will be determined e.g., how the consequential losses are being* *calculated or additional clarity on replacement reserves. Similarly, if the detailed algorithms used by the TSOs could be shared with service providers, this would ensure full transparency and predictability ahead of DASSA go-live. This is particularly important given the current uncertainty in the DS3 program.'*. One respondent adds that *'the replacement reserve methodology is also not clear as it seems to just be 75MW by default regardless of LSI/LSO or the makeup of the service providers. How this value is determined should be clearly identified and described in the Forecast Volume Methodology decision.'*.

One respondent considers that '*the degree of detail and foresight in (1) the types of reference incidents and (2) the amount of pre-DASSA volumes expected from other procurement mechanisms, are critical to being clear on real DASSA volumes needed.'*

Although there is general support to the principle of procuring reserves that take account of consequential losses, several respondents specifically mention that it is unclear how the TSOs will determine the consequential losses and their relation with FRT capability. One of these respondents notes *'the calculation of consequential losses in a given time period require complex calculations'*, but also argues that *'in the absence of a method by which market participants can attempt to calculate the likely reserve requirements emanating from the probability of consequential losses, it's difficult to truly evaluate the likely volume requirement of a given DASSA auction – which is the purpose of this consultation.'*. This respondent suggests that *'If it's not possible to specify an exact methodology by which consequential losses are calculated, perhaps it would serve industry better to provide archetypes of the system conditions that would lead to the probability for consequential losses to be either high or low. For example, in the weekly constraints' updates, tolerances are included alongside the forecast of constraints to inform participants of how the constraint may manifest depending on variable factors such as demand or wind production'*.

One respondent suggests that *'it would be beneficial if the TSOs set out the current extent of potential consequential loss events, such as the lack of fault ride-through capability, how this may evolve in the future, the risks this places upon the system and how the TSOs intend to resolve this issue'*.

Another respondent considers that *'Further detail is required on the output of the simulated studies for Upward Reserves (table 17). It is not clear how the requirements have been determined for 70%, 80% and 90% of FFR and FFR Category 2. No assessment or explanation has been provided, creating a lack of clarity of how future system needs will be determined by the TSOs*. Another respondent considers it *'not clear from the consultation paper is how the percentage of each largest single infeed/outfeed is being determined. In the consultation paper it seems to switch between 75% and 100% for certain products. Greater clarity on how such percentages, if being applied, are being determined are needed in the Forecast Volume Methodology.'*

<u>TSOs' response</u>

The TSOs acknowledge this issue and clarify that in the annual process described in section 5.3.2 of the consultation paper, the TSOs will perform simulation studies which will take account of the FRT capability of connected generation units, PPMs, LEU etc. The results will provide an indication on the volume of consequential losses for the study cases. Based on these simulation results, the TSOs will define consequential losses (see Box 7 below).

With respect to the minimum share of dynamic reserves, the TSOs will initially assume for their detailed power system simulation a share of dynamic reserves based on last year's minimum for dynamic reserves, coupled with an evaluation of historical experience and engineering judgement. The output of the set of simulation studies shall confirm the minimum dynamic POR and SOR for which the frequency will stabilise.

The process is similar for the minimum shares of FFR, FFR category 1 and FFR category 2. Also here, the detailed system simulation studies will rely on initial assumptions and the output of the simulation studies shall confirm that the instantaneous frequency deviation at the Nadir or Zenith will not exceed +/- 1000 mHz and the RoCoF will not exceed +/- 1 Hz/s.

The TSOs further refer to the annual report to provide more transparency on the how each element of the forecast volume methodology will be determined, including volumes of consequential losses.

Box 7: Methodology on determining Consequential losses

Consequential losses

Apart from the impact of the maximum LSI or LSO loss, the RI will also need to account for potential consequential losses of e.g. trips of generation or reduction of demand from demand units triggered by the same incident. Consequential losses take place if the triggering incident results in system changes (e.g. a lower voltage, frequency deviations), to which other generation or demand trip/reduce as well, resulting from e.g. lack of FRT capability of the concerned demand/generation.

Note that the consequential response does not include the intended response:

- Runback schemes and frequency response service on HVDC interconnectors, responding to the system frequency during the incident.
- Response of demand to a frequency deviation, typically reducing demand when the system frequency is reducing and vice versa.
- System defence measures.

Consequential losses can relate to infeed (CLI, e.g. DER) or outfeed (CLO, e.g. LEU). CLI and CLO are typically inadvertent (from a system perspective) and mainly caused by a lack of FRT capability of the units. This means that generation can disconnect and/or demand units can reduce demand automatically (e.g., switching to backup supply systems) because of protection devices/settings (e.g., under voltage or over/under frequency protection) responding to frequency/voltage disturbances resulting from the original incident. Note that given the relatively small size (i.e., with respect to the RI) and island nature of the All-Island power system, consequential losses can have a significant impact on system security if not properly mitigated.

Figure 4 below shows an illustrative example, starting from a balanced position. The incident is triggered by a *single* fault in a 500 MW exporting HVDC cable (1), resulting in an 'instantaneous change of active power' of 500 MW (2) and a change in voltage and frequency in the power system (3). Because of this, Under Voltage protections of demand units trip, adding – in this example – 200 MW to the imbalance (4). Accordingly, the total imbalance in the SEM caused by the trip of the 500 MW HVDC cable is 500 + 200 = 700 MW (5).

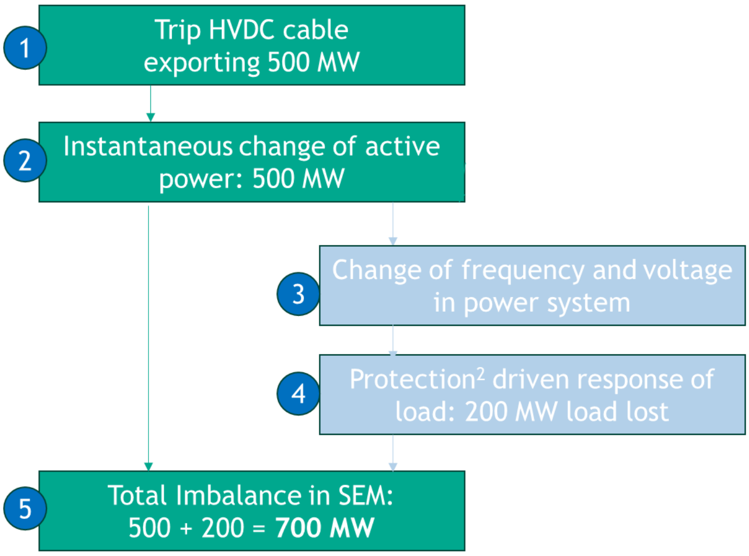


Figure 4: Illustrative example of consequential losses

Considering that large incidents do not happen very often, there is not a lot of experience with consequential losses. In December 2022, a line fault near Dublin triggered a consequential loss in the order of 204 MW, which represented a significant portion of total data centre demand at the time of incident. As can be seen in Figure 6, due to sensitive UPS voltage protection settings (e.g., 10% from nominal) data centre demand reduced for a prolonged period before being automatically restored. This demand reduction then caused a significant imbalance on the power system which led to a positive RoCoF and frequency rise (Figure 7). Note that similar responses have been observed by other TSOs in Europe and the USA. These performance issues have led TSOs to work on developing performance standards such as FRT for LEUs, for example, we cite ERCOT[57], USA, and RTE[58], France.

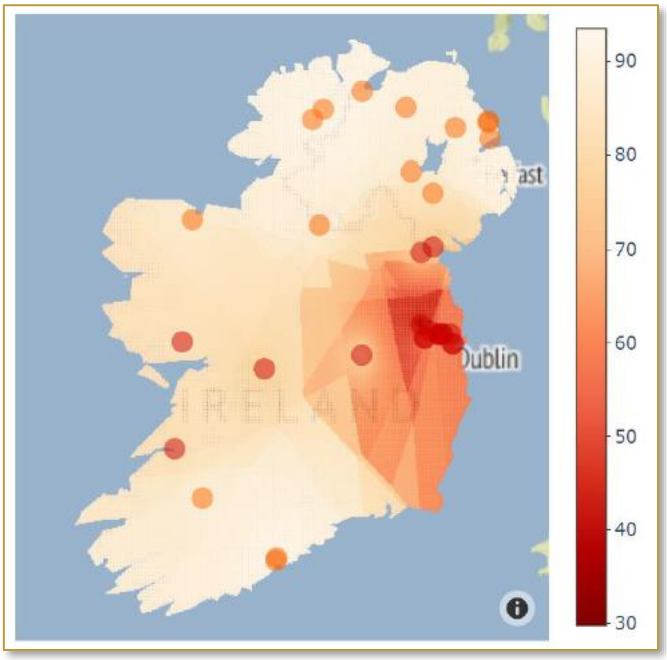
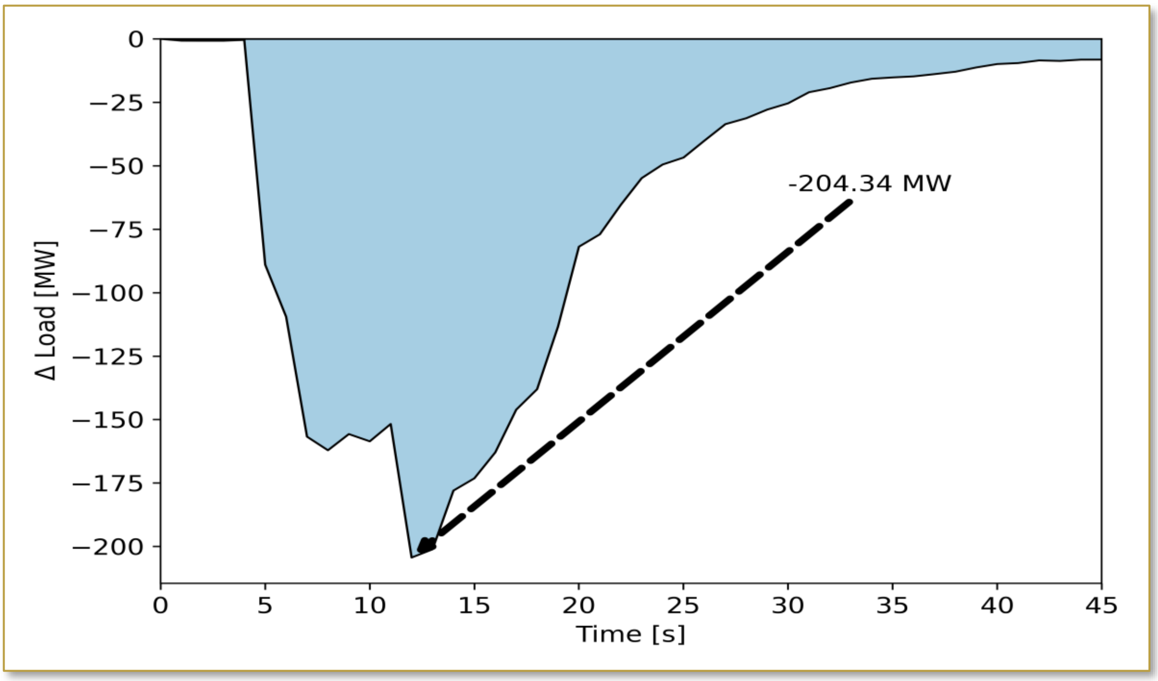


Figure 5: Example of voltage dip propagation following a 220 kV transmission fault in December 2022.



[57] ERCOT: Large Load Voltage Ride-Through Requirements

[58] RTE: https://www.services-rte.com/files/live/sites/services-rte/files/documentsLibrary/Article_8.3.5__CdC_des_capacites_constructive_d_une_installation_de_consommateurs_1897_fr

Figure 6: Example of aggregate data centre response (demand reduction) to a 220 kV transmission fault in December 2022.

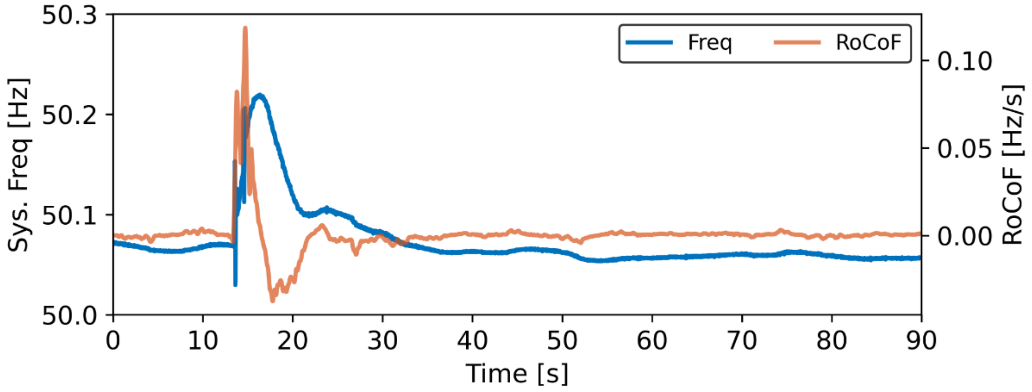


Figure 7: Frequency and RoCoF following a 220 kV transmission fault in December 2022.

As other TSOs face increasing DERs as well, they also experience consequential losses of DERs. For example, on four days in summer 2021 individual transmission line faults in the Californian power system triggered the reduction of PV generation with more than 511 to 765 MW or more than one third of the solar PV at that moment[59]. Similar events have been noticed between 2017 and 2021 in Australia[60].

Another well documented incident with consequential losses happened in Texas on 9 May 2021, at 11:21 AM. The incident was triggered by a fault at a generation plant resulting in a direct loss of 192 MW and a voltage dip. Figure 8 shows this voltage dip that appeared in one phase and had a duration of less than 50 ms[61]. This voltage dip was faced by connections (including solar PV) in a large area around the fault location, with the same duration, but with a higher residual voltage dependent on the distance to the fault[62]. The voltage dips caused approximately 25%, or 1.1 GW of solar PV to trip, as shown in Figure 9. Accordingly, this consequential loss of solar PV generation was more than five times the direct generation loss and resulted in a significant frequency deviation (0.2 Hz on a 60 Hz system).

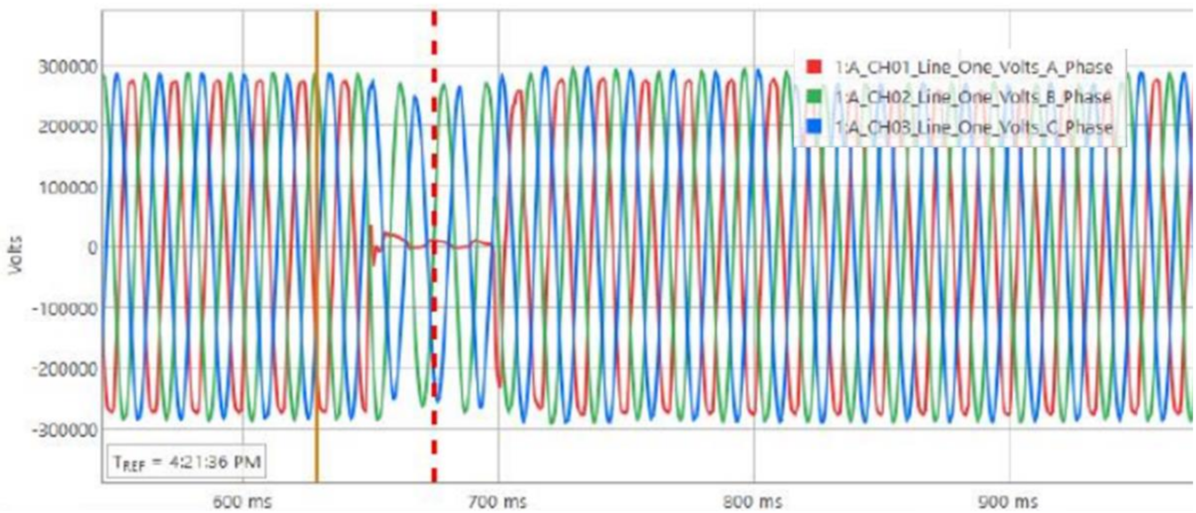


Figure 8: Voltage at 345 kV grid at fault location on 9 May 2021, 11:21:36 (source: NERC [63]).

[59] Report (nerc.com)

[60] Power System Incident Qld 25 May 21 Incident Report (aemo.com.au)

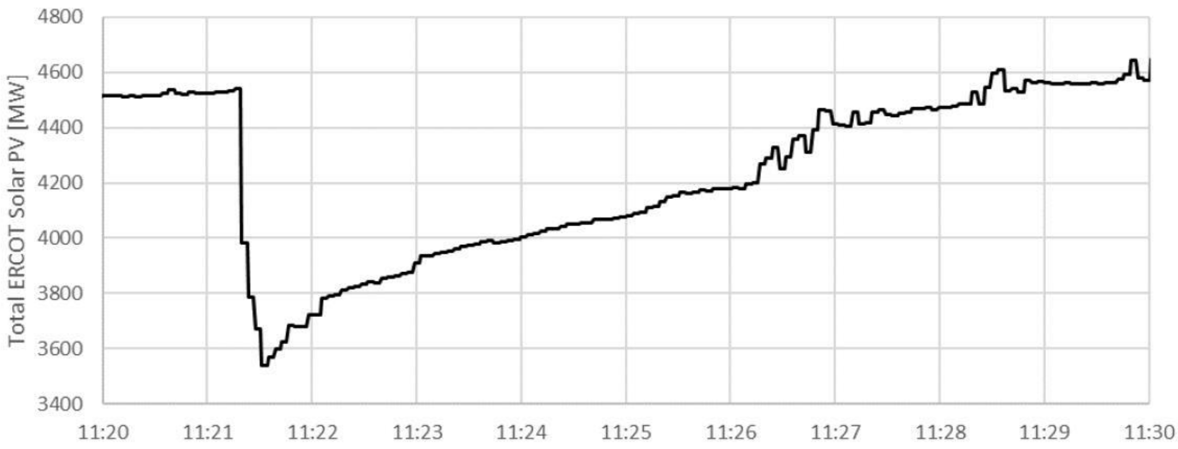


Figure 9: Solar PV generation in Texas on 9 May 2021 (source: NERC [64]).

On 9 August 2019, the Great Britain (GB) transmission system experienced a large incident triggered by a single circuit fault caused by a lightning strike. This resulted in a series of consequential events (see Figure 10), including the consequential loss of conventional plant, 737 MW of off-shore wind farm generation and more than 700 MW of distributed generation. Accordingly, the system frequency fell very quickly to 49.1Hz and below, which trigged the Low-Frequency Demand Disconnection scheme, interrupting another 550 MW of DER and the electricity supply to around 1.1 million customers for 15 to 45 minutes.

This event led the UK Government to "*recommend that there should be a review into the reserve and response holding policy of the NESO and whether it is fit for purpose going forward*"[65] and, in particular, to review the requirements for holding reserves including "*the explicit impacts of distributed generation on the required level of security;*"[66].

[61] Time required for clearing the fault.

[62] Related to the electrical distance to the fault location, the further away, the higher the residual voltage.

[63] Source: NERC (nerc.com)

[64] Source: NERC (nerc.com)

[65] GB POWER SYSTEM DISRUPTION – 9 AUGUST 2019: Energy Emergencies Executive Committee: Interim Report

[66] GB power system disruption on 9 August 2019: Energy Emergencies Executive Committee (E3C): Final report

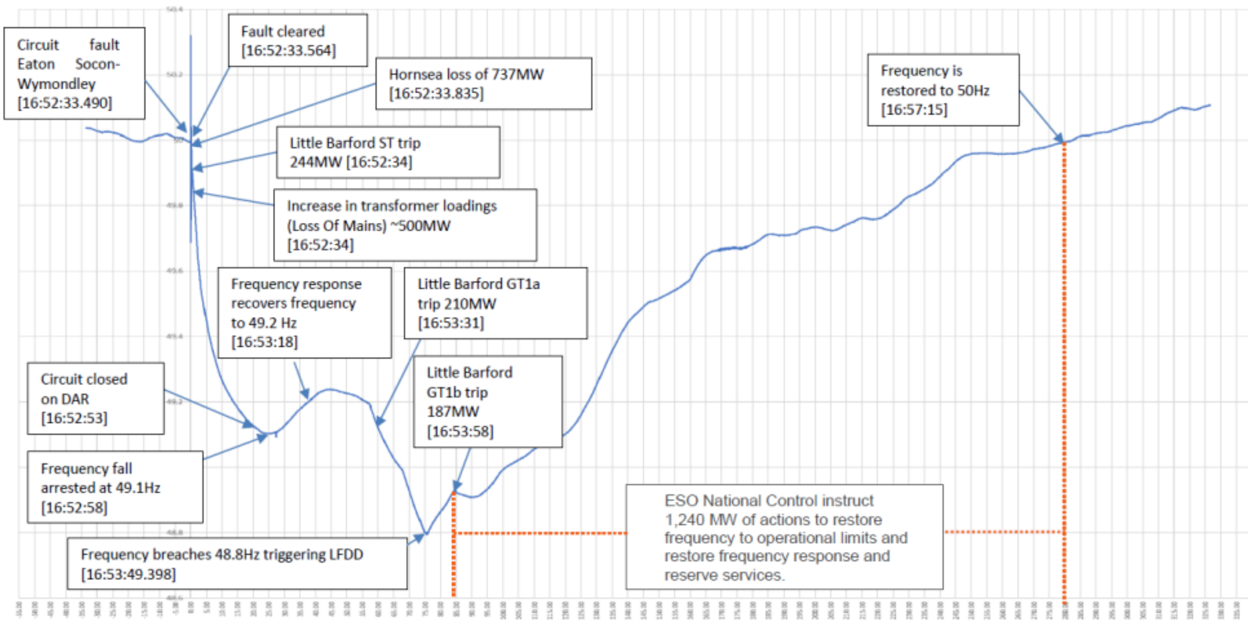


Figure 10: System frequency during the sequence of events in GB on 9 August 2019[67]

Apart from DER, demand units can also reduce demand automatically (e.g., switching to backup supply systems) because of protection devices/settings (e.g., under voltage or over/under frequency protection) responding to frequency/voltage resulting from the incident (see illustrative and actual examples above).

Mitigation of Consequential Losses

As Consequential Losses are mainly resulting from the lack of FRT capability, the mitigation measure is to implement adequate requirements that prevent consequential losses, including:

- Grid Code change to introduce FRT capability for LEUs[68]. This is critical considering the current and expected share of LEU demand (e.g., could account for 30% of peak demand by 2030).
- Developing standards for FRT capability of small DER (e.g., roof-top PV).

The TSOs consider that new requirements could be implemented in the relevant Codes and Standards by the start of DASSA, but implementation in relevant plant may longer.

Current consideration of Consequential Losses

The TSOs currently consider Consequential Losses when studying the security of their system close to (before) real-time through the Look-Ahead Security Assessment Tool (LSAT). This means that, for example, the response of LEUs is modelled in LSAT.

Consequential Losses in annual Forecasting Methodology

Considering the limited foresight at day-ahead stage, the TSOs consider including a fixed allowance for consequential loss factors CLI and CLO. These factors will be determined in the annual process as part of the methodology that is described in section 5.3.2 of the consultation paper. Particularly for Consequential losses the three steps of this methodology will include:

- *Step 1:* A 10-year forecast on consequential losses, based on additional capacity of new LEU and new DER, their FRT capability and the development and implementation of new (Grid Code) requirements on FRT capability.
- *Step 2:* In performing the detailed simulation studies for y+1, special attention will be paid to consequential losses. Hence, the output will show both components of the RIs: the LSI or LSO and the consequential losses. Based on the results for the RI, the allowance for Consequential

Losses is determined. This allowance will consider that a share of a certain infeed or outfeed category could consequentially trip, e.g. X% of LEU or Y% of DER. Where appropriate, the allowance may be time varying, for example, solar PV generation will not be at maximum capacity for the full day, and accordingly the potential consequential losses may vary.

- *Step 3:* The allowance for Consequential Losses resulting from step 2 is applied to determine the indicative reserve volumes for mitigating large disturbances (see table 18 of the consultation paper).

Figure 11 illustrates these steps in relation to the high-level annual process for volume forecast of reserves for mitigating large disturbances as described in section 5.3.2 of the consultation paper.

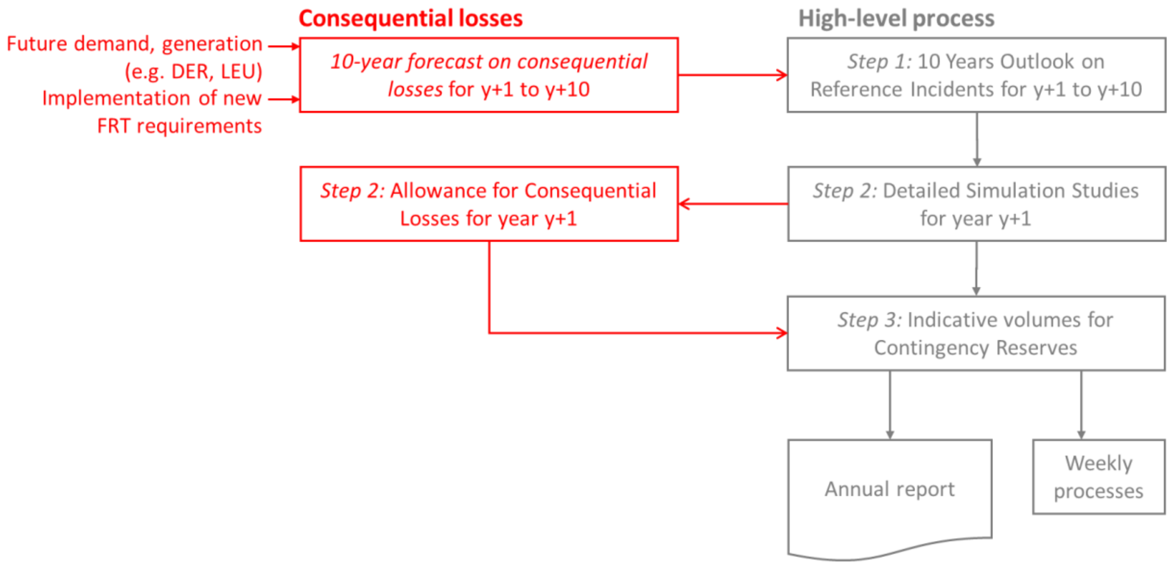


Figure 11: Determination of the allowance for Consequential Losses in the annual process for volume forecast of reserves for mitigating large disturbances (see section 5.3.2 of the consultation paper)

Box 8: Methodology on determining the allowance for Unavailability of Reserve Providers

Unavailability of Reserve Providers

To cater for circumstances where, after the DASSA auction has concluded, reserve providing units may become unexpectedly unavailable or local constraints may limit the possibility to dispatch some reserve providing units, actual available reserves may be lower than the reserves contracted day-ahead in DASSA. The TSOs therefore require an additional reserve volume component that mitigates unexpected unavailability of reserve providers that appears after DASSA. This allowance shall apply to FFR, POR, SOR, TOR1, TOR2 and RR.

Current consideration of Unavailability of Reserve Providers

As the TSOs currently schedule and dispatch up to real-time, reserve volumes are monitored and controlled based on actual availability. Hence, dispatchers ensure sufficient reserves of all types by scheduling and dispatching actions.

Relation to FAM alternative

The TSOs consider that the allowance for unavailability can be reduced or even set to zero if the proposed Residual Availability procurement (which is subject to consultation and SEMC decision) allows the TSOs to replace reserves procured in DASSA that became unavailable after DASSA. However, since there is no final decision on FAM alternative and no operational experience, the TSOs consider the

[67] Great Britain power system disruption - 9 August 2019 (publishing.service.gov.uk)

[68] Shaping Our Electricity Future Roadmap Version 1.1

proposed VFM approach valid (i.e., the allowance for unavailability can be a value >= 0, depending on the implementation of the FAM alternative).

To provide an alternative for the allowance for unavailability, the RAD or Secondary Trading should be usable in cases that a service provider becomes unavailable after DASSA, in case that a local constraint would prevent activation of the contracted capacity.

Unavailability in annual Forecasting Methodology

Subject to the sufficiency of FAM alternatives, the allowance for unavailability shall cater for:

- reserve providing units may become unexpectedly unavailable or
- local constraints may limit the possibility to dispatch some reserve providing units, e.g., due to a forced outage or a transmission restriction/fault.

The TSOs propose:

- *For 2026:* An initial allowance which caters for the largest reserve provider at the moment;
- *For the years after 2026:* During the annual process, evaluating and updating allowance for unavailability during the annual process, based on historical unavailability data and the opportunities to procure reserve volumes after DASSA.

Figure 12 illustrates how this methodology in relation to the high-level annual process for volume forecast of reserves for mitigating large disturbances as described in section 5.3.2 of the consultation paper.

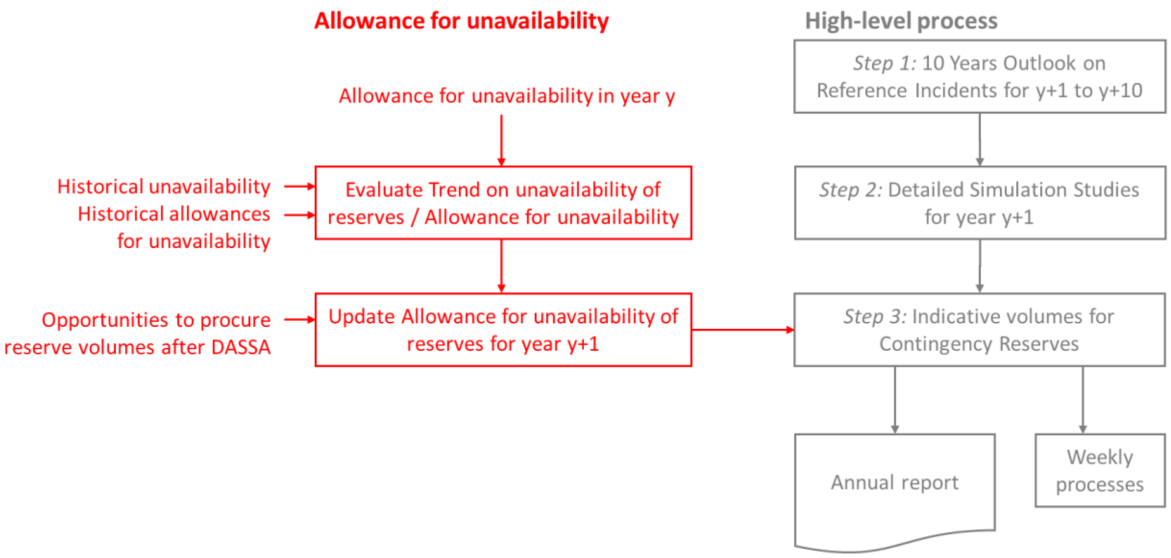


Figure 12: Determination of the Allowance for Unavailability of Reserve Providers in the annual process for volume forecast of reserves for mitigating large disturbances (see section 5.3.2 of the consultation paper)

Information and assessments from other established processes for 10-year forecast

One respondent recommends to '*Consider SOEF network uprates/reinforcements in the ten-year forecast of the annual process.*'. The rational for this is that '*by including SOEF network it will provide the up-to-date system uprates/reinforcements. Considering only GCS and TYTFS - it means that while the forecast considers expected system changes broadly, it may not fully integrate specific SOEF-driven network optimizations.*'

TSOs' response

The TSOs welcome the respondent recommendation and clarify that the reference to '*e.g. Generation Capacity Statements, Ten Year Transmission Forecast statements and the Transmission Development Plans*' in section 5.3.2 of the consultation paper was not conclusive. The TSOs will utilise information and assessments from other established processes to inform the 10-year forecast, which may also include the SOEF.

Detailed forecasts for 2026

One respondent *'would welcome a detailed volume forecast to be delivered in 2025 for 2026, and similarly in early 2026 ahead of DASSA delivery that year to ensure that service providers are informed of expected volume requirements ahead of DASSA go-live.'*

TSOs' response

The TSOs acknowledge the comment and note that they have provided the methodology to determine DASSA volume requirements and indicative reserve volumes which the TSOs consider informative for industry in terms of expected DASSA go live reserve volumes. As discussed in section 7 of the consultation paper, the TSOs propose that implementation of this reserve focused VFM would commence in 2026 with the publication of the first ten-year look-ahead forecast covering the period 2027 to 2036.

Dynamic vs Static

One respondent requires more explanation on *'the proportion of procured product that needs to be Dynamic v Static, is this influenced by the annual assessment?'* and if this will be a *'prescribed quantity in DASSA of x% dynamic capacity for POR, SOR and TOR 1&2, or can that % change day to day, week to week etc.?'*

Another respondent states that *'Static providers are mainly able to support the grid via load reduction. As the numbers of synchronized generators reduces which helps in absorbing imbalances on the system, the case for static provision for under frequency events should not be diminished but seen as crucial towards meeting system needs and arresting frequency drops, at lowest cost to the end consumer.'* The respondent further refers to *'The under-frequency event in the early hours of Tuesday 14th May 2024 where there was an unplanned loss of both the EWIC and Moyle interconnectors, from importing in excess of 900MW, approximately 25% of all-island demand at the time, has shown that the reference incident can be a combination of the first and second LSI units. From that frequency event, the frequency nadir dropped below 49.6Hz for the first time in 4 years.*

This respondent further argues that *'Despite low-cost static providers having the potential to contribute material volumes of reserve to cover such reference events, this does not seem to be adequately recognised in the methodology presented. The illustrative scenarios of calculated real-time available volumes of POR and system requirement published within the Current System Services Volume Requirements Information Paper showed only 10% of the Total POR Availability provided by DSUs in all the recorded scenarios.'*

This respondent also states that *'As the majority of DSU provision of frequency services is via static provision, setting the minimum dynamic volume requirements at 80% of the required volume risks being overly preferential to certain technologies that can provide dynamic services, and excluding other – potentially lower cost technologies – at the ultimate expense of the end consumer. The minimum levels of dynamic services to be procured should be reviewed so not to unnecessarily penalise non-dynamic providers.'*

In addition, this respondent states that *'the minimum level of service procurement which must be dynamic is an important design parameter and should only be set based on evidence from robust system studies / modelling which justify why a certain minimum requirement is needed. DRAI requests that the TSOs publish any such system modelling which justifies the 80% minimum dynamic volume threshold put forward in the Volume Forecasting Consultation.'*

TSOs' response

The TSOs acknowledge that low-cost static reserves provided by load customers can be an efficient means to secure reserves that support part of the mitigation of rare events with large frequency deviations. The TSOs however note that a minimum volume of dynamic response is required also in these situations to stabilise the system frequency after disturbances. Also, for continuously keeping the frequency within the 49.9 to 50.1 Hz range for 98% of time, the system requires dynamic response, which cannot be replaced by static response. Hence, the system needs a certain minimum share of the reserves to be dynamic with the remaining proportion able to be sourced from static providers. To determine this share (see section 5.3.2 of the consultation paper), the TSOs will apply detailed simulations to confirm the minimum dynamic POR and SOR for which the frequency will stabilise (Current dynamic simulation capabilities are limited to POR and SOR timelines).

One of the respondents refers to the illustrative scenarios in chapter 3/Table 4 of the recent Current System Services Volume Requirements Information Paper[69] in which indeed approx. 10% of the POR requirement seems to be covered by Demand Side Units (DSUs). The TSOs note that – as discussed in section 3.3 of that paper – the reserve contribution of DSUs was not determined dynamically based on the real-time outputs (as it was done for conventional units and interconnectors) but assumed in the scenarios at 65 MW. The same section 3.3 notes that during actual system events, when reserves are triggered, these unit types may contribute additional reserves which assists in the secure operation of the power system. The TSOs note that their indicative and illustrative examples in the consultation document (table 18 and 20) would allow for 20% of static response.

Volumes pre-DASSA (grid code, layered procurement, fixed contracts)

Several respondents consider the interaction *'between the DASSA, LCF and Fixed Contract volume*' is unclear. They request explanation on how '*Volumes pre-DASSA (grid code, layered procurement, fixed contracts)'* and '*transition arrangements'* will be quantified in the methodology and '*how this dynamic will work*'. One respondent considers this is required '*to give an accurate picture of proposed forecast volumes in relation to proportion of volumes procured elsewhere. Market participants need to know which investment routes they are likely to target.'*

In addition, the respondent comments that *'On pre-DASSA volumes, the forecast methodology does not show a methodology for dealing with pre-DASSA volumes, or for situations that could become more prevalent in future (demand load reductions etc). The degree of over-procurement proposed cannot be understood in context without this additional detail of external factors or volumes that will drive DASSA related volume forecasts.'*

TSOs' response

With respect to the interaction *'between the DASSA, LCF and Fixed Contract volume*', we refer to further explanation in section 6.1.56.1.5.

With respect to the methodology for dealing with pre-DASSA volumes, the TSOs refer to section 5.5.3 of the consultation paper stating that *'the TSOs will take account of any reserve products and volumes that are already contracted and available at the time of a DASSA auction, and reduce the final volumes required by an equivalent amount.'*.

Magnitude of reserve volumes

Several respondents refer to the TSOs' statements at the stakeholder workshop on 17 October. The respondents' understanding resulting from this workshop is that *'the magnitude of the system service requirement would appear to be anywhere up to 900MW. Is it the intention of the TSOs to procure this kind of provision via the consequential loss element as to not do so would leave the system under-procured and reliant on free riding on grid code requirements?'*.

Another respondent considers it unclear *'why some of the minimum volume requirements for different reference incidents are set between 70%-100% of the RI*'. And '*why varying percentages are used*' in the examples. This respondent feels that *'stronger justification must be provided for the determination of the % of LSO/LSI to be procured.'*

TSOs' response

The TSOs confirm that their proposal for a provision for consequential losses in the definition of the RIs (see section 3.3 of the consultation paper). As the RIs will determine the required volumes (see section

[69] DS3_System_Services_Current_System_Services_Volume_Requirements_Information_Paper.pdf

5.3/Table 17 of the consultation paper), a provision for consequential losses will be implicitly in the reserve volumes to be procured.

The TSOs further note that the illustrative example of 900 MW referred to in the workshop will be a possible result of the VFM for the All Island requirements for POR, SOR, TOR1, TOR2 and RR. However, the TSOs further note that the VFM consultation paper sets out the methodology for volume forecasting and that the actual volume forecasting will be first done in the course of 2026, and based on detailed simulations for Y+1.

On the percentages indicated in the illustrative examples, the TSOs confirm that the 100% levels suggested for total POR, SOR, TOR1, TOR2 and RR volumes are based on the methodology proposed in section 5.3.2 of the consultation paper and the system need reflected in sections 3.3.4 and 3.3.5 of the consultation paper. The percentages below 100% are illustrative and will be determined in the annual process by detailed simulations. These percentages include the required volumes and speed of FFR and the minimum share of the volumes that shall be provided by dynamic reserves.

However, the TSOs further note that the VFM consultation paper sets out the methodology for volume forecasting and that the actual volume forecasting will be first done in the course of 2026.

4.3. TSOs' considerations

Considering the responses received to Question 3 of the consultation paper, the TSOs have updated their recommendations as outlined above and these have been summarised in the Executive Summary chapter.

5. Recommendations on Implicit Bundling

5.1. Summary of proposal

In the consultation paper, the TSOs outlined options for the determination of a minimum requirement for implicit bundles, to be calculated ex-ante based on either:

- A Percentage of Individual Requirements
- No Minimum Requirement

The TSOs proposed that the DASSA information pack will include the minimum requirement value to facilitate informed bidding strategies by service providers. The DASSA design will allow for the definition of new products if required in the future, including explicit bundles should the TSOs identify a technical need for same.

5.2. Consultation responses

The question we asked in relation to this section was:

Chapter 6. Implicit Bundles	Question 4. Do you have any comments on the proposed considerations and options for setting the minimum requirements for implicit bundles? Please provide a detailed rational if you consider additional aspects need to be considered?

5.2.1. Question 4. Do you have any comments on the proposed considerations and options for setting the minimum requirements for implicit bundles?

The responses received to Question 4 indicated that seven respondents were not in favour of the TSOs' approach towards bundling, particularly the exclusion of explicit bundles from DASSA go-live and the perceived lack of information regarding the objective function. Two respondents were in favour of the TSOs' proposals for implicit bundles, while two respondents were mixed in their responses. One respondent did not comment.

Bundling in the context of TSO recommendations and SEM Committee decisions

Six respondents consider the TSOs' proposal to exclude explicit bundles from DASSA go-live to be in contrast with previous SEM Committee decisions e.g., *'It is not clear why the TSOs have determined not to introduce explicit bundles in light of the SEMC decision paper to include them for Go-Live in SEM 24 066 DASSA Market Design of 16 Sept '24. The consultation paper refers to no operational requirement for explicit bundles and implicit bundles, however, it seems to be the lack of a system need for explicit bundles as the justification for not having them for Go-Live yet implicit are needed.'*

TSOs' response

The TSOs recognise that the development of the TSOs' service bundling proposition has been set out in several published DASSA papers. The SEM Committee has also made decisions concerning the bundling of system services in two papers.

Below, for clarity, we summarise the key TSO recommendations and applicable SEMC decisions to date.

- July 2024 – TSO DASSA Design Recommendations Paper:
    - This paper was submitted to the SEMC on 31/07/2024 and published by the TSOs on 18/09/2024.

- The TSOs recommended that the design of the DASSA allow for the procurement of both implicit and explicit bundles of services.
- The services to be procured in the DASSA, and any bundles of those services, were to be subject to the outcome of the TSOs' subsequent Product Review & Locational Methodology consultation.

- Sep 2024 – TSO DASSA Product Review and Locational Methodology Recommendations Paper:
    - This paper was submitted to the SEMC on 04/09/2024 and published by the TSOs on 04/10/2024.
    - The TSOs did not recommend the procurement of explicit bundles of reserve services as a system operational need for such was not identified in our studies.
    - The TSOs recommended that a process be developed to define implicit bundles of reserve services in a flexible way, with the objective to support efficient auction outcomes.

- Sep 2024 – SEM-24-066 SEMC DASSA Market Design Decision Paper:
    - The SEMC decided that the DASSA will initially procure reserve services, both on an individual service basis and for any explicit bundle of services that may be defined as an individual product in the auction.
    - The SEMC also decided that the auction design will allow for the procurement of implicit bundles of services.

- Oct 2024 – TSO DASSA Volume Forecasting Methodology Consultation Paper:
    - The TSOs reiterated that an operational requirement to procure bundles of services has not been identified; however, we noted that bundles can mitigate certain market-related issues as well as ensuring more efficient DASSA outcomes for service providers.
    - The TSOs stated that it is intended that only implicit bundles of services will be procured through the daily auction for DASSA go-live.
    - The TSOs proposed options for determining how a minimum requirement for implicit bundles would be calculated ex-ante.
    - The TSOs advised that defining the value of the volume requirement for implicit bundles will be in scope for the TSOs' DASSA Parameters and Scalars Consultation, which is scheduled to be published in Q1 2025.

- Oct 2024 – SEM-24-074 SEMC DASSA Product Review and Locational Methodology Decision Paper:
    - The SEMC decided that the TSOs should create definitions for an equivalent explicit bundle to remove the need for that implicit bundle as quickly as is practical; no specific milestone was stated for this decision.
    - The SEMC considered that implicit bundles should only be used where there is a clear system need.
    - The SEMC also decided that a separate workstream needed to be established to further explore bundling options; no milestone was stated for this decision, with the SEMC noting that an enduring solution for bundling may not be implemented for DASSA go-live.

- Oct 2024 – System Services Future Arrangements (SSFA) Project Panel:
    - The October SSFA Project Panel (meeting #5), chaired by the RAs, took place on 21/10/2024.
    - The RAs' consultants Nera presented on an alternative design for bundles of services arising from linked bids.
    - The TSOs understand that this was for the purposes of discussion only and does not represent a SEMC position for implementation at DASSA go-live or any future date.

Description of Implicit Bundles

Multiple respondents noted that additional information is required to fully understand the functionality and implications of implicit bundles within the DASSA e.g., *'In any event, greater clarity on how implicit bundles will provide value to the customer, and not unnecessarily increase complexity'*.

Two respondents highlighted a lack of worked examples, without which they cannot come to a definitive position e.g. *'It would be helpful if the TSOs could provide some detailed worked examples for setting the requirements for implicit bundles, including a 'day in the life' example. It is difficult to comment further when we are waiting on the TSOs providing further information on the design and operation of implicit bundles in the DASSA regime'*.

Five respondents specifically mentioned concerns or a need for further information regarding the objective function in relation to implicit bundles e.g., *'There is still a substantial lack of clarity surrounding the objective function within the optimisation problem. Until further detail is provided, it is not possible to determine if the objective function is an effective tool to determine the procurement volumes for implicit bundles. To be clear, the inability to provide a position due to a lack of information should not be taken as acceptance of either methodology. Instead, this should be reconsulted on once stakeholders have been provided with greater clarity.'*

TSOs' response

The TSOs acknowledge respondents' requests for more detail on how implicit bundles will work in the DASSA. In this section, coupled with the worked examples of the objective function set out in Appendix A, the TSOs provide further details of implicit bundling functionality.

The TSOs will establish and publish a volume requirement for implicit bundles daily for each Trading Period (as part of the DASSA volume requirement for reserve services). The value of this volume requirement may be zero.

A 'simple' bidding process will be implemented for the DASSA go-live, meaning that service providers will submit price-quantity pairs for each individual service for each individual Trading Period. There will be no interdependency between bids for different services or Trading Periods. For the avoidance of doubt, complex or combinatorial bidding will not be implemented for DASSA go-live.

Where an implicit bundle volume requirement greater than zero is set by the TSOs, an implicit bundle of reserve services will be modelled as a constraint in the auction clearing. The clearing will satisfy the constraint if sufficient volumes of the component services have been bid in to the auction (otherwise, there would be an instance of volume insufficiency for a service).

The clearing price for the implicit bundle of services will be at least the sum of the clearing prices of each individual component service of the bundle.

Should there be an instance of volume insufficiency in the clearing of an implicit bundle of services, there are two options available to the TSOs:

- The impacted service(s) would receive the scarcity price for the service, which would then be included in the summation of the individual service clearing prices.
- The TSOs would not procure an implicit bundle of services.

As with other auction constraints, such as jurisdictional reserve minimum volumes, once the volume requirement for the implicit bundle has been met, then the residual volume requirement for each service will be cleared individually.

Predefined value functions will be added to the objective function of the DASSA clearing optimisation problem. The value of the value functions will be based on the TSOs' willingness to pay for the continuous provision of services above the volume set for the implicit bundle constraint. These value functions may increase the probability of service providers that have submitted bids that together constitute the continuous provision of a subset of services being awarded DASSA Orders in the auction for all those services i.e. an implicit bundle of services. The value functions will be included as transparent auction parameters.

Please refer to Section 4.10.3 of the DASSA Design Consultation Paper and Section 3.12.4 of the DASSA Design Recommendations Paper for a description of the objective function. Appendix A below provides worked examples of the objective function's implicit bundling functionality.

Rationale and Benefits of Implicit Bundles

Two respondents elaborated on the rationale and potential benefits of the TSOs' proposals for implicit bundles. One response highlighted the perceived benefits from implementation e.g., '*The proposed considerations for implicit bundles are logical, as bundling services could potentially reduce procurement complexity and improve market efficiency. The suggested approach to allow implicit bundles of upward and downward reserves, provided they meet minimum capability requirements, will enable service providers with versatile assets to contribute to system needs flexibly.*'

Another considered the benefit of implicit service bundles with minimum volume requirements, e.g., '*As the TSOs need to justify the efficiency of the objective functions and in accordance with the SEMC decision as regarding implicit bundle of reserve services, option 2 which requires no minimum requirement i.e. setting a minimum volume requirement of zero for implicit bundles of services would provide less information for service provider's ex-ante and as such [we] support option 1, where the TSOs develops a methodology for setting static minimum volume requirements for implicit bundles.*'

TSOs' response

In this section, the TSOs elaborate on the rationale for implicit bundles and the potential issues that they will be designed to resolve.

The TSOs consider that implicit bundles provide the following benefits:

- Service providers retain the flexibility of being able to submit separate bids for each of the individual services in the DASSA.
- In comparison to explicit bundles of services, where a service provider must be able to provide the full range of services constituting the bundle, implicit bundles do not constrain the participation of any service provider or technology type in the daily auction.
- As with explicit bundles, implicit bundles provide operational efficiencies for service providers that can provide a consistent volume across consecutive services.
- As the procurement of the full volume requirement of individual services in the daily auction facilitates the participation of all service providers, it can be expected that there will be increased competition in the auction.
- Having the ability to clear different services that make up a bundle separately (as in the case of implicit bundles) can mitigate against market power abuse. By way of contrast, a large service provider that believes it is needed for one service in an explicit bundle could leverage this to clear at a higher price across the bundle of services.
- As with explicit bundles, implicit bundling can address concerns relating to the exclusion of excess volume from the ex-ante energy markets, which may occur if individual services of varying volumes are procured from multiple service providers. The procurement of a bundle of several consecutive services in a continuous manner from a limited number of service providers would mitigate against this issue, allow for a more efficient allocation of resources and ultimately provide better value for the consumer.

5.3. TSOs' considerations

In summary, the TSOs will be implementing functionality that allows for implicit bundles of services for DASSA go-live in December 2026. The TSOs consider that this is consistent with SEMC decisions to date. As noted above, the volume requirement for implicit bundles will be in scope for the TSOs' upcoming DASSA Parameters and Scalars Consultation. Other categories of bundles, such as explicit bundles or those arising from linked bids, are not in scope for DASSA go-live; these will be addressed in a separate workstream as directed by the SEMC, the schedule for which will be captured in future versions of the PIR (from March 2025 onwards).

The TSOs consider that any changes to the bundling arrangements for DASSA go-live will impact the go-live date of December 2026; in addition, the TSOs are concerned that other bundling activities may divert resources from the DASSA implementation, potentially impacting the go-live date.

6. Other Considerations Raised by Industry

The majority of industry participants in response to Questions 1-4 and also more generally in their submitted responses discussed topics and concerns that were broader than the specific questions. In combination with the responses provided on Question 5 and we wish to capture these in terms of the common themes raised these thematically and address our responses to each thematic area.

6.1. Consultation responses

The question we asked in relation to this section was:

Chapter 7. Next Steps	Question 5 Do you consider there are other aspects that need to be taken into account as part of a Volume Forecasting methodology for the reserve services? Please provide detailed rationale for any recommendations you wish the TSOs to consider.

6.1.1. Greater TSO/DSO interaction and demand flexibility requirements consideration required

Several respondents requested greater clarity on TSO/DSO interactions and the need for greater collaboration with the DSOs;

'As the DSO begins to manage more flexibility services, a reporting framework between the TSO and DSO would enhance visibility into reserve contributions from the distribution network. This coordination would be especially valuable in regions with high levels of DERs, where localised flexibility can support system reserves. Establishing a standardised DSO-TSO data exchange and reporting protocol could also streamline the integration of distributed resources into the broader reserve structure'.

'Also to consider is the interaction of this forecast with: (1) demand flexibility requirements (e.g. NEDs) and (2) the degree of dispatchable demand volumes on the distribution system is also not included. The inclusion of such demand would lend a fuller detail on the volumes required to be procured for system stability and resilience.'

TSOs' response

In relation to the request to include demand flexibility requirements, there is ongoing separate work to enable demand flexibility by both SONI and EirGrid, as illustrated in the recently published Demand side response Whitepaper[70] and preparation for the forthcoming EU requirements for flexibility assessments is underway across European TSOs and DSOs. Further work is anticipated with the future EU Network Code on Demand response. However, such workstreams are not specifically focused on reserve product provision. The TSOs, in this paper, are recommending a VFM for the approved reserve products for procurement in DASSA, and as such are proposing a technology neutral approach while also wishing to accommodate as many provider types as possible.

In relation to the comments related to joint TSO-DSO frameworks, the TSOs, in addition to responses provided to Question 1 in section 3.2.1 of this paper wish to reiterate that we have detailed work underway with both ESBN and NIEN as part of the development of the Joint System Operator TSO-DSO Future Operating Model[71]. Further consideration of a standardised TSO-DSO data exchange will be required as part of implementation of the requirements of the forthcoming Network Code on Demand response[72].

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70 EirGrid-and-SONI-TSO-Demand-Side White-Paper-December-2024.pdf

71 TSO/DSO Joint System Operator Programme (eirgrid.ie), SONI Forward-Work-Plan-2024-25.pdf

72 PC_2024_E_07 - Public consultation on the draft network code on demand response | www.acer.europa.eu

6.1.2. EU standard products

Several respondents have raised queries on the utilisation of EU standard balancing products.

'.. the product review for reserves should have used EU standard products as the baseline and we would consider this now must be retrospectively reflected since otherwise, for future product reviews of other services, there will be inconsistent treatment and definition of products being procured.'

'The SEMC is clear that the baseline for products needs to be standard products with any deviations robustly explained.'

'We also agree with the SEMC that the product review for reserves should have used EU standard products as the baseline and we would consider this now must be retrospectively reflected since otherwise, for future product reviews of other services, there will be inconsistent treatment and de4nition of products being procured.'

TSOs' response

In line with industry comments the SEMC Decision on the Product Review & Locational Methodology has requested the TSOs to undertake an additional product review and examine alignment with EU standard products. This review will be undertaken as outlined in the updated PIR roadmap of DASSA workstreams. For additional context we provide some further detail on EU standard products below which are separated into balancing capacity and balancing energy products:

- Balancing Capacity: a volume of reserve capacity that a balancing service provider has agreed to hold and in respect to which the balancing service provider has agreed to submit bids for a corresponding volume of balancing energy to the TSO for the duration of the contract.
- Balancing Energy: energy used by TSOs to perform balancing and provided by a balancing service provider. Balancing service providers either offer balancing energy bids to their TSO following the obligation from a balancing capacity contract or voluntarily.

Balancing energy standard products are FCR, FRR and RR, and have defined minimum activation times and duration times. The DASSA reserve products are Balancing capacity products. As per Annex 1 of the 'Methodology for a list of standard products for balancing capacity for frequency restoration reserves and replacement reserves'[73] and as required by Article 3(1)(b) of the EB Regulation the methodology defines a list of standard products for balancing capacity from frequency restoration reserves and replacement reserves especially for the exchange between TSOs to foster cost efficient procurement. Currently the SEM TSOs do not exchange reserves with any EU TSOs (nor with the GB TSO), and if this is required in future it would require agreements to ensure cross zonal capacity is allocated for balancing capacity exchange, supported by a cost-benefit analysis.

If in the future there is a decision made to establish balancing capacity exchanges across an EU interconnector there will be a need to align with the standard balancing capacity products, including on validity period. The validity period of bids from standard balancing capacity products shall be equal to the day-ahead market time unit or be a multiple of the day-ahead market time unit (see table in Annex 1[74] for more info). The current DASSA design has a product validity period of 30 mins, and the design also allows for other durations for future evolution.

Currently, there is no pan-EU platform for the exchange of standard balancing capacity products. With the introduction of such a platform, as outlined in the EBGL (Article 27.3), and the Methodology for standard balancing capacity products, for TSOs that use an integrated scheduling process (Central dispatch TSOs) "*Each TSO applying a central dispatching model shall use integrated scheduling process bids for the exchange of balancing capacity or sharing of reserves pursuant to Article 27(1) of the EB Regulation and*

[73] ACER Decision on SPBC: Annex I

[74] ACER Decision on SPBC: Annex I

convert as far as possible the integrated scheduling process bids to the standard balancing capacity product bids if the TSO exchanges balancing capacity or shares reserves for a given type of a standard product for balancing capacity" a conversion process would have be established ***if*** the TSOs decide to exchange balancing capacity. Additionally, for exchange or sharing of reserves cross-border there would be a need to integrate the proposed volumes of shared or exchanged reserve volumes in Regional Coordination Centre (RCC) processes for Coordinated Capacity Calculation[75] relevant to the allocation of capacity on a cross border (SEM- EU) interconnector. This work would be captured as part of the wider SEM-EU re-integration work.

6.1.3. FFR Minimum Full activation time (FAT) reduction

Two respondents queried the reduction (as covered in the TSOs DASSA Product review recommendations and SEMC decision paper) of the FFR minimum FAT to 1 second from the previous requirement of 2 seconds. Respondents indicated *'This is a clear signal to renewable assets which currently provide the service of 1s to 2s to no longer retain the provision of this service. Has the TSOs identified that they no longer need this service and that they are in a position to run the system without this service? This is a critical aspect that existing providers must be aware of so they can consider their investment decisions for the future.'*

TSOs' response

The TSOs' note the comments received and refer to the prior approval of this reduced activation time by the SEMC in their Decision paper on the Product Review and Locational methodology. For further context, and as outlined in the TSOs' Product Review and Locational Methodology consultation and recommendations papers, to manage contingency events, fast acting FFR is required to ensure frequency deviations remain within +/- 1000 mHz (i.e. keep the Nadir ≥ 49.0 Hz and Zenith ≤ 51.0 Hz) and to keep the RoCoF below 1 Hz/s.

The main drivers for FFR volumes and speed are the RI and availability of inertia (see Figure 7 in section 3.3.3 of the consultation document), i.e. for the same RI, more volume of faster FFR is required if the inertia levels are lower. For a larger RI, the FRR requirements further increase. Additionally, as outlined in the Product Review recommendations paper, over 70% of the existing FFR providers are able to provide FFR with a FAT of less than 1 second. It is to address these requirements that the TSOs proposed a change from a 2 seconds minimum FAT to 1 second minimum FAT, and the subsequent approval by the SEMC of this proposal.

The TSOs are aware that the move to a day ahead auction format and new product definitions will bring different investment considerations for potential participants, and wish to ensure transparency on design aspects throughout the process.

6.1.4. SEMC Decision on Product Review and Locational methodology paper.

Several respondents have outlined concerns on matters relating to the SEM Decision paper on the DASSA Product and Locational Methodology (SEM-24-074). While this paper is focused on the VFM for reserve services, we have decided to provide extra clarity in this section based on the number of comments raised by participants in relation to product definition and locational methodology aspects.

For clarity in that paper the SEMC decided the following, and we provide the TSOs' response to each decision in terms of required work and timelines below;

Reserve Product Definitions: The SEM Committee approved the proposed product designs for the reserve services, subject to a further product review being carried out in 2026.

- TSOs' response: This work is being planned for 2026 with the understanding that the outcomes are not in scope or implementable (due to downstream programme dependencies) for 'Day One'

[75] Coordinated Capacity Calculation | Coreso

DASSA go live. Outcomes may however be delivered post Go Live, subject to feasibility assessed at that time. Further detail on the timing of these activities to be outlined as part of PIR V3.0.

EU Alignment Considerations: The SEM Committee considers that further analysis is needed in relation to the extent to which European standard products can meet system needs and on the need to deviate from or supplement those products. This analysis should be included in the next product review.

- TSOs' response: Additional context on EU standard products has been provided in earlier in this chapter.
- As noted above, this work is being planned for 2026 with the understanding that the outcomes are not in scope or implementable (due to downstream programme dependencies) for 'Day One' DASSA go live.

Bundling: The SEM Committee decided that a workstream exploring options for bundling is to be established, and a consultation will take place on bundling in the future.

- TSOs' response: We have provided an update on considerations on implicit bundling in Chapter 5 of this paper.
- The TSOs note the RAs position on bundling. An additional workstream will be added to PIR V3.0, however activities to commence this will only be possible after the completion of 'Day One design and implementation activities to avoid impacting to schedule. Bundling considerations outside the scope of SEM-24-066 are considered as a 'Day Two' activity and need to be treated as such.

Locational Requirements: The SEM Committee has decided to approve the TSOs' recommendation to maintain current locational reserve requirements for upward reserves and to introduce the same locational requirements for downward reserves. Additionally, the SEM Committee requires, as per the HLD, the TSOs to develop and consult on a locational methodology for system services, prior to DASSA go-live.

- TSOs' response: The TSOs are currently engaging with the regulators to understand the need for an additional locational methodology for frequency-based reserve services (and in keeping with requirements for synchronous area operational agreements and load frequency control block agreements).
- Additionally, the TSOs will provide further clarification on the processes and methodology to determine the jurisdictional requirements for reserve services. This clarification will be provided as part of the second Product Review & Locational Methodology in 2026. However, note that no additional zones will be implemented for 'Day One' DASSA go live.

Reserve Product Scalars: In consideration of the DASSA Market Design decision the SEM Committee requires the TSOs to carry out further consultation to determine unit performance standards at the point of activation. The incentivisation of always maintaining availability, up to and including real-time dispatch, should be dealt with through the commitment obligation framework.

- Detailed consideration of the unit performance standards and ensuring appropriate incentivisation of required availability will be a feature of the upcoming Parameters and Scalars consultation.

6.1.5. Interactions between LPF, Fixed Contracts and DASSA, and Grid code alignment

Several respondents have raised concerns that there is insufficient detail provided on the interactions between the Layered Procurement Framework, Fixed contracts and the DASSA auctions in the paper. Respondents have indicated that a more cohesive outline of the procurement of all system services across the various mechanisms, including the DASSA, layered procurement framework (LPF) and fixed contracts, is required to provide certainty to service providers and enable investment in new assets. In addition, clarity has been requested on the interaction of grid code requirements with volume based procurement.

'Little information or stakeholder engagement has taken place on the potential interactions and impacts of the wider FASS programme (Layered Procurement Framework and Fixed Contract) with the DASSA. The consultation states that pre-procured volumes from FASS and DS3 System Service Volume capped

contracts will influence the volumes required to be procured within the DASSA. This has not been discussed with industry and no explanation has been provided on how these pre-procured volumes will impact this methodology. Detailed proposals and further consultation are required on what this means in practice i.e. will volumes from these services be removed from the DASSA volume requirements or will they be utilised as alternative sources, retained based on availability and utilised during periods of volume insufficiency? (We) believe that the volumes determined by the methodology should determine DASSA procurement values. Without further detail on these proposals, it creates reduced confidence in the DASSA, potentially resulting in under-procurement which requires an overreliance on TSO involvement in secondary trading.'

'We believe that there is insufficient visibility of interaction between the DASSA, LCF (LPF) and Fixed Contract volumes and how this dynamic will work.'

'We also agree with the SEMC DASSA Product decision that Grid Code interactions are not clear so the starting point of the volumes in this methodology appear to be only related to the new products needed in reserves, we assume? But this does not consider, due to lack of detail, the provision of reserves that are now no longer eligible in the overall volume forecast. These are important hidden factors that would affect the volumes forecast and the certainty that market participants have regarding whether their offerings will be taken or displaced by other dispatch instructions from the TSO. And since the risk for dispatch away from a position by the TSO is placed on market participants, then forecasting and certainty in actual volumes must be much clearer, accurate and encompassing.'

'[We have] have substantial concerns surrounding the TSOs for configuring the deadband setting of providers through System Services Code development and the Grid Code. It is not clear how this may impact system service providers and has been included without consultation. It was believed that participation in the DASSA was voluntary, however, it appears that it may become mandatory by using the Grid Code as a back door to enforcing system service requirements on all participants. It is essential that all proposals undergo the appropriate and thorough public consultation process. As this has not been consulted on, it cannot be forced upon participants within the System Service or Grid Code. [We do] not support the approach being taken to place requirements on providers without appropriate discussion or consideration of potentially more efficient alternatives.'

'The SEMC HLD notionally mentions a 40% volume to be procured through DASSA. We have mentioned before that this arbitrary proportion has not been confirmed is sufficient to meet the EU requirements for market-based procurement. The current forecast paper does not really reference this or other total volumes to be procured and also does not demonstrate it would be fit for purpose where all or the majority of reserves and/or other services could be procured via DASSA.'

TSOs' response

The TSOs would like to clarify that the reference in our consultation paper to the removal of any pre-procured volumes from FASS and DS3 System Service volume capped arrangements is in line with previous SEMC Decisions and the TSOs' obligations to procure sufficient volumes of reserves to ensure system security and ensure economic efficiency.

In the SEMC SSFA Phase III Detailed Design 23-103 paper[76] the SEMC stated *'In terms of how the enduring approach will function, there are requirements under Article 6(9) of the Clean Energy Package Regulation (EU 2019/943) which states that "at least 40 % of the standard balancing products and a minimum of 30 % of all products used for balancing capacity, shall be concluded for no more than one day before the provision of the balancing." This clearly indicates that daily auctions should account for at least 30% of all volumes for reserve products. It can therefore be interpreted that the DASSA will account for at least 30% of procurement for reserve services, while any remaining volumes requirement and other services can be procured through the additional frameworks available to the TSOs, being the LPF and Fixed Contract Arrangements.*

[76] SEM-23-103 - SSFA Phase III - Phased Implementation Roadmap - Decision Paper.pdf

The SEM Committee considers that all services should be procured through a market-based approach and in the most economically efficient manner feasible.'

Subsequently in the SEMC DASSA Design decision paper 24-066[77] it is stated '*The SEM Committee also notes that the volume requirements should take account of volumes procured pre-DASSA.'*

The TSOs have developed a VFM based on system needs i.e. identifying the necessary volumes of reserve products required for secure system operation. The volumes that are then required to be procured from DASSA will be discounted by the volumes of DASSA reserve products that are contracted through other mechanisms (as described in sections 3.3.8 and 5.5.3 of the consultation paper).

As per section 6.12 of the System Services Future Arrangements High Level Design Decision Paper (SEM-22-012), the original intention of the LPF was to provide a means of procuring System Services ahead of the short-term energy and balancing capacity markets, as provided for under Regulation (EU) 2019/943. As per the HLD, the LPF applies to the procurement of System Services for periods greater than one day ahead, up to 12 months ahead of provision of the capacity. In the SEM 24-066 paper further detail has been provided on considerations the TSOs should undertake in relation to LPF procurement, particularly in relation to the removal of the original proposed FAM mechanism.

As previously noted in Section 3.2.23.2.1, extensive examination of alternative possible mechanisms to the FAM has been undertaken and the TSOs will be consulting on the proposed RAD in early 2025. It is the TSOs intention is that the DASSA will be the primary procurement method for reserve services, with the proposed RAD mechanism proposed to incentivise real-time availability and address any DASSA volume deficits. Thus, the RAD will procure real time system requirements beyond the initial forecasted DASSA, and fill any 'gaps' that would have been met by DASSA volumes that have since lapsed.

The TSOs acknowledge the concerns raised by industry regarding these matters and are committed to collaborating with the Regulatory Authorities to ensure clarity for service providers on the various procurement mechanisms as part of the DASSA Arrangements in a timely manner.

In terms of the queries on the interaction of Grid Code requirements the TSOs clarify that mandatory requirements for frequency response capabilities are contained within the Grid Codes. To ensure sufficient reserve provision the TSOs recommend that (as previously recommended in the TSOs DASSA Design recommendation paper[78]) service providers be obligated to declare their availability to provide a service to the TSOs if they are technically capable of doing so, irrespective of whether they hold a DASSA Order for the service volume. The TSOs also recommend that as part of the proposed development of the RAD system services providers shall be obliged to declare their forecast system services capability ahead of real time. Further detailed implementation of such requirements will be covered within the development of the System Services Code.

Further work is ongoing, as outlined in the DASSSA Product design recommendations paper & as approved by the SEMC to ensure a comprehensive and aligned approach is taken to DASSA product design, Grid Code and System services code. Please refer to Milestone 15 as outlined in the PIR[79], with any identified Grid Code modifications to be progressed from 2025 onwards.

The TSOs acknowledge the need to ensure cohesion between the DASSA Auction Design, Product Recommendations and VFM, and wish to reassure industry participants that there is strong coordination and collaboration across workstreams in terms of the development of all of the DASSA and FASS arrangements.

We will continue to provide updates on progress, and in line with previously shared information at our monthly Future Power Market workshops[80] we intend to expand on worked examples of DASSA and ex ante market participation through this forum.

[77] SEM-24-066 - SEMC FASS DASSA Design Decision Paper.pdf (semcommittee.com)

[78] FASS Programme Day-Ahead System Services Auction (DASSA) Design Recommendations Paper V1.0

[79] FASS-TSOs-PIR-September-2024-EirGrid.pdf

[80] Electricity Markets Future Power Market workshops| Shaping Our Electricity Future | EirGrid

6.1.6. Interactions with energy markets and dispatch

'The DASSA needs to be designed in such a way that it incentivises all possible technologies to operate within DASSA effectively. In light of the SEMC decision paper, there is a risk for service providers from the unknown impact of TSO actions moving participants out of position. The severity of this risk will be determined by

a) the ability to trade within the Secondary market,

b) the design of a FAM alternative,

c) Commitment obligations levels and

d) Volume forecasting accuracy.

Some technologies may be able to accommodate this TSO action risk in their bids in the energy market, however renewable assets may not be able manage this risk to the same affect due to bidding restriction and the SEMC interpretation of the Clean Energy Package. This topic needs further exploration

Energy Market Interactions

The DASSA needs to be designed in such a way that it incentivises all possible technologies to operate within DASSA effectively and make an informed decision regarding day ahead decisions to trade capacity and/or system services. The risk to service providers associated with TSO actions that move participants out of position will be determined by:

a) the ability to trade within the secondary market,

b) the design of a FAM alternative,

c) commitment obligations levels and

d) volume forecasting accuracy

Some technologies may be able to accommodate risk associated with this TSO action in their bids in the energy market, however renewable assets may not be able to manage this risk to the same affect due to bidding restriction and the SEMC interpretation of the Clean Energy Package.

The potential exposure to non-payment and penalties due to TSO action may disincentivise volumes of reserves bidding into DASSA – which in turn could have a knock-on effect on volume forecasting. Under the components which will determine the volume forecast, unavailability of reserve providers has an impact on DASSA Reserve Volume (Chapter 3.3). This unavailability must be considered from both an operational and a commercial/ regulatory perspective. Due to the continued interactions between DASSA and the energy markets, (we) would welcome a workstream to look at interactions between DASSA and energy markets to assess how issues such as the one outlined above will operate.

One respondent indicated that the risks to investment are considerable given the uncertainty on revenue and service provision which in their view is exacerbated by ongoing DASSA developments (e.g. FAM alternatives).

'Industry responses reflect additional shared considerations from market participants trying to decide whether the new DASSA is an investable proposition, and how the change in reserve products will impact existing service providers who are now no longer eligible to provide some services.

This uncertainty needs to be more fully reflected in the volume forecast methodology along with a long overdue plan regarding the interaction and relationship between DASSA, layered procurement and new fixed term contracts.

In addition, there needs to be an acknowledgement of this uncertainty more broadly and specifically with the necessity that the TSO sees with a FAM alternative, when the SEMC was incredibly clear that the FAM would not be compliant with EU market-based requirements. The continued requirement the TSO has for reserve requirement being maintained is unequivocal. But, this is being achieved seemingly external to the DASSA, through complete opaque and decoupled approach to the dispatch of system services compared to the procurement of system services. As above, the forecast methodology could be used to *better and transparently address the requirement. What the TSO does not acknowledge is that auction procurement which does not translate into dispatch, diminishes the investment signal to participate or enter the DASSA, which further fuels the risk the TSO feels in being unable to fill their reserve requirement and other system service needs.*

Where some parties may be in favour of FAM because they cannot currently participate in the Balancing Market(this) is more to do with current SEM shortcomings that will need to be remedied in future (i.e. ultimate move to market-based constraints and curtailment and bidding code reform), than it is a justification for the TSO to continue to favour a static mechanism in the FAM that cannot endure following EU re-integration.

It is worth also noting that the SEMC is clear that the baseline for products needs to be standard products with any deviations robustly explained. This points to a realisation that where these are standard products by default they must be market-based for participation and procurement which in our view includes dispatch.

<u>TSOs' response</u>

Energy market interactions

As outlined in Section 3.2.13.2.2, there will be industry consultation in early 2025 on the RAD. In relation to the points raised on energy market interactions the TSOs are very much cognisant of the complexity of considerations that market participants will have both in terms of evaluating both DAM and DASSA bids, and managing delivery and TSO actions post market gate closures. Within all of the existing FASS workstreams underway we endeavour to ensure early transparency for market participants. We do not consider at this point that an additional workstream can be facilitated as requested, but will work to ensure that the interactions with energy markets are considered as part of ongoing work.

In relation to the comments focused on a decoupled approach to the DASSA procurement and dispatch requirements, the TSOs have indicated in multiple publications that the FASS programme does not incorporate scheduling and dispatch system changes. Similar to other EU member states who procure balancing capacity, and as per EBGL Article 16 requirements, TSOs are not allowed to discriminate between balancing energy bids (in SEM these equate to inc's and dec's) submitted by holders of Balancing capacity contracts, or balancing energy bids submitted by non DASSA holders. As outlined in the previous documents Balancing capacity products are quite varied and only a small number of TSOs are actively utilising cross border balancing capacity products.

6.1.7. Replacement reserve procurement – volume determination and activation considerations

One respondent raised issues on RR procurement and bid selection.

Currently, it is not clear if RR must be fulfilled by different service providers than those supplying POR/SOR/TOR, or if the same providers can cover both needs. The consultation puts the RR volume requirements similar to POR/SOR/TOR; however, if the same providers are used for all services there can be a risk of under procurement. For instance, if resources providing POR through TOR are activated, they may not have enough capacity left to meet RR needs, potentially compromising system readiness for subsequent events. To solve the issue, the TSO could potentially set the RR requirements to be higher than POR/SOR/TOR.

Conversely, if the TSO intends for RR to be sourced from other sources - e.g. quick start off-load unit(s) than come on to provide RR while those providing TOR-POR drop back and are ready for next event – this could address the issue but requires clarity on how this can be achieved through an auction.

<u>TSOs' response</u>

In relation to the query on whether RR can be delivered by a unit already contracted day ahead for POR, SOR, TOR and RR (and potentially activated close to real time) for POR, SOR and TOR, actual delivery will be determined as a result of PNs submitted by units, frequency deadbands and system conditions. The auction design is based on bid selection of the most economically efficient provider of each product, and delivery will be based on PN submission that aligns with successful bids. The objective function of the auction will determine the appropriate selection of providers per product based on the published volume requirements. Separately, in the operational phase the TSOs will ensure a schedule that enables sufficient service availability for TSO operations. Detailed bid selection and activation requirements will be fully considered as part of the System services code development.

In the case of batteries or other energy limited assets, where activation of a series of products (i.e. POR/SOR/TOR) in succession might make them unavailable to be activated for RR, it is expected that the service provider bidding for these products would bid for a suitably lower volume so that they would be capable of delivering their obligations if they are cleared for a range of products. Service providers will also have opportunity to trade out of being cleared for an undesired position via Secondary Trading if they bid and clear for higher volumes.

6.1.8. Interaction with non-reserve services

Some respondents queried the interaction with the non-reserve services.

'The new Phased Implementation Roadmap has a consultation scheduled for 2025 for the non-reserve products. Whilst the FASS development is running in sequence, it is not clear if the volume forecast methodology will be different for non-reserve products and if there will be any interaction between these two methodologies that needs to be considered for responding to this consultation paper. Ideally, the approach should be similar so that service providers have clarity if they provide multiple services.

Further clarity is required around the daily publications. It is unclear at present but we can only assume that the DASSA daily publication at 10am will be for all services and not only reserves?'

TSOs' response

The TSO welcomes these queries and clarifies that there will be a consultation on non-reserves services in 2025 that will cover a product review and volume considerations. However, note that it is not the intention that non-reserve services will form part of the initial DASSA auctions, but the products are being reviewed in terms of suitable future procurement mechanisms, which could include Day-ahead auctions at some point.

6.2. TSOs' considerations

The TSOs having considered the responses submitted by industry to Question 5 have updated their recommendations on the VFM which have been summarised in the Executive Summary chapter. We outline further forthcoming work in Chapter 7.

7. Summary and Next steps

The TSOs have outlined in this paper their final recommendations on the VFM that will be utilised to determine the volumes of products procured in the DASSA auctions, taking into account the detailed responses received from industry during the consultation. The TSOs value greatly the input and feedback provided by industry which has helped shape the final recommendations. The SEM Committee will review the proposed recommendations and will issue a decision in Q1 2025 on this.

Subsequent implementation of the final VFM will need to be formalised through the development of the system services code, the grid code review and the licencing and governance workstream. Additionally, adequate resourcing and funding will need to be provided for, to ensure that the production of the first annual forecast will be available in advance of the first DASSA auction in 2026, and to ensure the production of the weekly and daily volume requirements are facilitated in time for DASSA go-live.

This recommendations paper focuses only on reserve services. A separate Product Review and Locational Methodology consultation is envisaged during 2025 to examine the required product design for the other (non-reserve) DS3 System services.

The TSOs will continue to engage with industry on our forthcoming auction design proposals, Grid Code alignment workstreams, System Service code development, and are preparing for a consultation on the design of Performance Scalars in 2025, and a consultation on the proposals in relation to the RAD.

8. Appendix A

This section contains worked examples of the application of implicit bundle functionality, demonstrating the outcomes of the value function in the objective function.

8.1. Inputs and Assumptions for Worked Examples

8.1.1. Assumptions

1- **Product Definition**: Consider two services, S1 and S2 that constitute a bundle.
2- **Locational Considerations:** For simplicity, suppose that there is no locational consideration.
3- **Divisibility:** Suppose that all bids are divisible.
4- **Minimum Requirements:** The minimum requirement for S1 and S2 is set out in the following table (note that there is no minimum requirement here for the bundle of S1 and S2):

	Minimum Requirement for Individual Services [MW]
S1	200
S2	150
Bundle of S1 & S2	0

5- **Value functions for the bundle:** Suppose that the TSOs' willingness to pay to procure S1 and S2 from a single service provider (as a bundle) is €2. That means the TSOs are happy to pay €2 above the individual service prices, if they can procure S1 and S2 as a bundle.
6- **P-Q pairs:** Suppose that there are four service providers (i.e., U1, U2, U3, and U4) that can participate in the auction and the following P-Q pairs have been submitted by these service providers for each service. As indicated by the submitted P-Q pairs, U3, and U4 are not intending to provide both services, therefore only U1 and U2 can potentially provide S1 and S2 as a bundle. Please note that the volumes are cumulative.

Unit	Service	P-Q Pairs
Unit U1	S1	$\{(5,50), (7,100)\ , (10,120), (11,150)\}$
	S2	$\{(4,30), (5,60)\ , (9,90)\}$
Unit U2	S1	$\{(7,30), (9,120), (10,200)\}$
	S2	$\{(5,80), (7,120), (9,200)\}$
Unit U3	S1	$\{(4,50), (5,120)\}$
Unit U4	S2	$\{(3,20), (4,50)\}$

8.1.2. Implicit Bundle supply function for U1

Based on the P-Q pairs submitted by U1, an implicit supply function can be calculated for the bundle of S1 and S2 that could be procured from U1.

As recommended in the TSOs' DASSA Design Recommendations paper[81], the price offered for an implicit bundle of services from a single service provider will be the summation of the prices that have been offered for individual services constituting that bundle. Since U1 has offered 30 MW of S2 at the price of €4 and 50 MW of S1 at the price of €5, as a result, the first P-Q pair for an implicit bundle of S1 and S2 will be $(9,30)$. Other P-Q pairs can be calculated accordingly.

Bundle from U1: $\{(9,30), (10,50)\ , (12,60), (16,90)\}$

8.1.3. Implicit Bundle supply function for U2

Similarly, based on the P-Q pairs submitted by U2, an implicit supply function can be calculated for the bundle of S1 and S2 that could be procured from U2.

Bundle from U2: $\{(12,30), (14,80)\ , (16,120), (19,200)\}$

8.1.4. Merit Order for supplying the implicit bundle:

Based on the calculated implicit bundle supply functions for U1 and U2, an aggregated supply function for the implicit bundle of S1 and S2 can be calculated as below:

Implicit Bundle Supply Function: $\{(9,30), (10,50)\ , (12,90), (14,140), (16,210), (19,290)\}$

Off the back of the implicit bundle supply function, the corresponding merit order for the implicit bundle of service (S1 & S2) is as follows:

Unit	$(\boldsymbol{p}, \boldsymbol{Q})$	Incremental $\boldsymbol{q}$ [MW]
U1	(9,30)	30
U1	(10,50)	20
U2	$(12,30)$	30
U1	$(12,60)$	10
U2	$(14,80)$	50
U2	$(16,120)$	40
U1	$(16,90)$	30
U2	$(19,200)$	80

8.1.5. Residual supply functions for individual services

By solving the market clearing optimisation problem the amount of volume that can be allocated to U1 to U4 as individual services, and the amount of volume that can be allocated to U1 and U2 as an implicit bundle of S1 & S2 will be determined. To that end, the residual supply function should be calculated for each unit that can provide the implicit bundle based on the submitted P-Q pairs.

For example, if the optimisation allocates 40 MW of the implicit bundle of S1 and S2 to U1, then the residual supply function for U1 will display the remaining P-Q pairs available for providing individual services. In other words, the residual supply functions indicate the prices for the additional quantities that

[81] https://cms.eirgrid.ie/sites/default/files/publications/EirGrid-and-SONI-DASSA-Design-Recommendations-Paper-September-2024.pdf

U1 is willing to supply, beyond the amount already allocated as the implicit bundle of S1 and S2. The residual supply function of U1, after allocating 40 MW of the implicit bundle is calculated as below:

Residual S1: $\{(5{,}10), (7{,}60), (10{,}80), (11{,}110)\}$

Residual S2: $\{(5{,}20), (9{,}50)\}$

8.1.6. The Residual Merit Order

If the optimisation allocates zero volume of the implicit bundle to the units, the merit orders for the individual services S1 and S2 will be as follows. Note that the second column shows the ranking of all P-Q pairs in the merit, while the third column represents the incremental volume offered by each P-Q pair as the submitted P-Q pairs are cumulative.

Service S1

Unit	(p, Q)	Incremental q [MW]
U3	(4,50)	50
U1	(5,50)	50
U3	(5,120)	70
U1	(7,100)	50
U2	(7,30)	30
U2	(9,120)	90
U1	(10,120)	20
U2	(10,200)	80
U1	(11,150)	30

Service S2

Unit	(p, Q)	Incremental Q
U4	(3,20)	20
U1	(4,30)	30
U1	(5,60)	30
U2	(5,80)	80
U4	(5,50)	30
U2	(7,120)	40
U1	(9,90)	30
U2	(9,200)	80

8.1.7. How to clear the market in the presence of value function for the implicit bundle of services

To demonstrate how the optimisation process works, we follow the steps outlined below:

1) **Assume an optimal value:** Start by assuming an optimal value for the implicit bundle of S1 and S2. Then, the clearing price for the implicit bundle can be obtained by allocating the assumed optimal value to the units based on the aggregated merit order. Note: the initial optimal value here is an estimate, which will converge on the actual optimum value by the end of the examples.
2) **Calculate the residual merit order:** Subtract the volumes already allocated to the assumed optimal bundle from the unit's offered volumes to obtain the residual merit order. Adjustments to the residual merit orders are indicated by crossing out previous values and re-writing in green font (in the tables in the worked examples below).
3) **Determine the individual service price:** By allocating the residual volume of individual services to the units based on the residual merit order, the prices for individual services will be obtained.
4) **Evaluate clearing prices:** Assess whether the clearing prices align with the TSOs' willingness to pay for the implicit bundle of S1 & S2. If the prices are compatible, then the assumed volume for the implicit bundle is validated. If not, adjust the assumed the volumes for the implicit bundle and repeat all the steps.

It is important to note that these steps are for illustrative purposes only to show how the market could be cleared to procure the bundle of services as well as individual services. In practice, a single market clearing optimisation will be solved.

8.2. Implicit bundle worked examples

8.2.1. Example 1) How to calculate residual merit order for each service

Suppose 40 MW is procured from U1 as the implicit bundle of S1 and S2. Based on Step 2, the residual merit orders will be adjusted as follows:

Residual Merit for Service S1

Unit	(p, Q)	Incremental q [MW]
U3	(4,50)	50
U1	(5,~~50~~ 10)	~~50~~ 10
U3	(5,120)	70
U1	(7,~~100~~ 60)	50
U2	(7,30)	30
U2	(9,120)	90
U1	(10,~~120~~ 80)	20
U2	(10,200)	80
U1	(11,~~150~~ 110)	30

Since 40 MW has been allocated to U1 as the implicit bundle, the original (5,50) pair should be adjusted to reflect only the residual volume, which is 10 MW. Furthermore, because all P-Q pairs were cumulative, all subsequent volumes offered by U1 in the merit order should be adjusted accordingly.

Residual Merit for Service S2

Similarly, the same logic can be applied to obtain the residual merit for S2.

Unit	(p, Q)	Incremental q [MW]
U4	(3,20)	20
~~U1~~	~~(4,30)~~	~~30~~
U1	(5,~~60~~ 20)	~~30~~ 20
U2	(5,80)	80
U4	(5,50)	30
U2	(7,120)	40
U1	(9,~~90~~ 50)	30
U2	(9,200)	80

8.2.2. Example 2) Market clearing by assuming 150 MW for the implicit bundle

Step 1:

Suppose that we procure 150 MW as a bundle of S1 and S2.

We calculate the bundle supply functions per service provider (i.e., U1 and U2).

Bundle supply function from U1: $\{(9,30), (10,50), (12,60), (16,90)\}$

Bundle supply function from U2: $\{(12,30), (14,80), (16,120), (19,200)\}$

Therefore, 150 MW can be allocated as below:

- 60 MW to U1 (offered at a price of €12 or higher); and
- 90 MW to U2 (offered at a price of €16 or higher).

To represent this allocation in the merit order for the implicit bundle of services (S1 & S2), the table below highlights the fully accepted increments in green and the partially accepted increment in gold.

Unit	(p, Q)	Incremental q [MW]
U1	(9,30)	30
U1	(10,50)	20
U2	(12,30)	30
U1	(12,60)	10
U2	(14,80)	50
U2	(16,120)	40 (only 10MW is allocated)
U1	(16,90)	30
U2	(19,200)	80

Step 2 for S1:

Now the residual merit order for individual service S1, can be obtained.

Unit	(p, Q)	Incremental q [MW]
U3	(4,50)	50
~~U1~~	~~(5,50)~~	~~50~~
U3	(5,120)	70
U1	(7,~~100~~ 40)	~~50~~ 40
~~U2~~	~~(7,30)~~	~~30~~
U2	(9,~~120~~ 30)	~~90~~ 30
U1	(10,~~120~~ 60)	20
U2	(10,~~200~~ 110)	80
U1	(11,150)	30

Step 2 for S2:

Now the residual merit order for individual service S2, can be obtained.

Unit	(p, Q)	Incremental q [MW]
U4	(3,20)	20
~~U1~~	~~(4,30)~~	~~30~~
~~U1~~	~~(5,60)~~	~~30~~
~~U2~~	~~(5,80)~~	~~80~~
U4	(5,50)	30
U2	(7,~~120~~ 30)	~~40~~ 30
U1	(9,~~90~~ 30)	30
U2	(9,~~200~~ 110)	80

Step 3 for S1:

Given the 200 MW volume requirement for S1, the residual volume requirement for S1 is 50 MW. Based on the above merit order for S1, 50 MW residual volume can be allocated to U3 by fully accepting its first P-Q pair (highlighted in green).

This allocation sets the clearing price for the individual service S1 to be €4. However, any additional volume of S1 would need to be procured by assigning volume to the next offer in the merit order, which, in this case, comes at a higher price of €5.

Step 3 for S2:

The TSOs do not need to allocate any volume to service providers individually to meet the requirement for S2 as this has been already fulfilled through the assumed allocated volume for the implicit bundle of S1 and S2.

However, any additional volume of S2 must be procured by assigning volume to the first P-Q pair in the merit order, which, in this case is U4, offering 20 MW at a price of €3.

Step 4:

Based on the marginal prices calculated for each service at Step 3 (i.e., €5 for S1 and €3 for S2), the TSOs could procure additional individual services at a total cost of €8. However, the marginal price for the implicit bundle of services is €16 assuming the optimal allocated volume for the bundle is 150 MW.

The difference between €16 and €8 is much higher than the TSOs' willingness to pay, which is set at €2 (the value function). Therefore, we need to revise the assumed optimal volume for the bundles and repeat all 4 steps.

8.2.3. Example 3) Continuing example 2 by revising the optimal implicit bundle to 90 MW

Step 1:

Suppose that we procure 90 MW as a bundle of S1 and S2.

We calculated the bundle supply functions per service provider (i.e., U1 and U2).

Bundle supply function from U1: $\{(9,30), (10,50)\,, (12,60), (16,90)\}$

Bundle supply function from U2: $\{(12,30), (14,80)\,, (16,120), (19,200)\}$

Therefore, 90 MW can be allocated as below:

- 60 MW to U1 (offered at a price of €12 or higher); and
- 30 MW to U2 (offered at a price of €12 or higher).

To represent this allocation in merit order for the implicit bundle of service (S1 & S2), the table below highlights the fully accepted increments in green. Therefore, the clearing price for bundle of services is €12 and the marginal price would be €14.

Unit	(p, Q)	Incremental q [MW]
U1	(9,30)	30
U1	(10,50)	20
U2	(12,30)	30
U1	(12,60)	10
U2	(14,80)	50
U2	(16,120)	40
U1	(16,90)	30
U2	(19,200)	80

Step 2 for S1:

Now the residual merit order for individual service S1, can be obtained as below.

Unit	$(\boldsymbol{p}, \boldsymbol{Q})$	**Incremental $\boldsymbol{q}$ [MW]**
U3	(4,50)	50
~~U1~~	~~(5,50)~~	~~50~~
U3	(5,120)	70
U1	(7,~~100~~ 40)	~~50~~ 40
~~U2~~	~~(7,30)~~	~~30~~
U2	(9,~~120~~ 90)	~~90~~ 60
U1	(10,~~120~~ 60)	20
U2	(10,~~200~~ 170)	80
U1	(11,~~150~~,90)	30

Step 2 for S2:

The residual merit order for individual service S2, can be obtained by applying the same logic.

Unit	$(\boldsymbol{p}, \boldsymbol{Q})$	**Incremental $\boldsymbol{q}$ [MW]**
U4	(3,20)	20
~~U1~~	~~(4,30)~~	~~30~~
~~U1~~	~~(5,60)~~	~~30~~
~~U2~~	(5,~~80~~ 50)	~~80~~ 50
U4	(5,50)	30
U2	(7,~~120~~ 90)	~~40~~ 30
U1	(9,~~90~~ 30)	30
U2	(9,~~200~~ 170)	80

Step 3 for S1:

Given the 200 MW volume requirement for S1, the residual volume requirement is 110 MW. It can be readily procured by allocating 110 MW to U3. However, (5,120) will be allocated partially. Therefore, the marginal price for procuring on additional MW of S1 would be €5.

Unit	(p,Q)	**Incremental q [MW]**
U3	(4,50)	50
~~U1~~	~~(5,50)~~	~~50~~
U3	(5,120)	70 (60 MW is allocated)
U1	(7,~~100~~ 40)	~~50~~ 40
~~U2~~	~~(7,30)~~	~~30~~
U2	(9,~~120~~ 90)	~~90~~ 60
U1	(10,~~120~~ 60)	20
U2	(10,~~200~~ 170)	80
U1	(11,~~150~~,90)	30

Step 3 for S2:

Given the 150 MW volume requirement for S2, the residual volume requirement is 60 MW. This can be allocated to U4's first P-Q pair and partially allocated to U2's residual (5,50) pair. Therefore the marginal price of procuring S2 would be €5.

Unit	(p,Q)	**Incremental q [MW]**
U4	(3,20)	20
~~U1~~	~~(4,30)~~	~~30~~
~~U1~~	~~(5,60)~~	~~30~~
~~U2~~	~~(5,80~~50)	~~80~~ 50 Only 40 MW is allocated
U4	(5,50)	30
U2	(7,~~120~~ 90)	~~40~~ 30
U1	(9,~~90~~ 30)	30
U2	(9,~~200~~ 170)	80

Step 4:

Based on the marginal prices calculated for each services at Step 3 (i.e., €5 for S1 and €5 for S2), the TSOs could procure additional individual services at a total cost of €10. However, the marginal price for the implicit bundle of services is €14 assuming the optimal allocated volume for the bundle is 90 MW.

The difference of €14 and €10 is again higher than the TSOs willingness to pay which is set at €2 (the value function). Therefore, we need to revise the assumed optimal volume for the bundles and repeat all 4 steps.

8.2.4. Example 4) Continuing example 3 by revising the optimal implicit bundle to 80 MW

Step 1:

Suppose that TSOs procure 80 MW as the implicit bundle of S1 and S2.

The bundle supply functions per service provider (i.e., U1 and U2) were calculated as below.

Bundle supply function from U1: $\{(9,30), (10,50), (12,60), (16,90)\}$

Bundle supply function from U2: $\{(12,30), (14,80), (16,120), (19,200)\}$

Therefore, 80 MW can be allocated as below:

- 60 MW to U1 (offered at a price of €12 or higher); and
- 20 MW to U2 (offered at a price of €12 or higher).

Or another alternative could be:

- 50 MW to U1 (offered at a price of €12 or higher); and
- 30 MW to U2 (offered at a price of €12 or higher).

There would be no difference in the resulting clearing prices between the two possible alternatives. For this analysis, we use the first alternative, which allocates 60 MW to U1 and 20 MW to U2.

Note: The result of the second alternative (allocating 50 MW to U1 and 30 MW to U2) can be found in Section 8.3 Alternatives below labelled as "Alternative 1".

To represent this allocation in the merit order for the implicit bundle of services (S1 & S2), the table below highlights the fully accepted increments in green and partially accepted increments in gold. Therefore, the clearing price for a bundle of services is €12 and the marginal price would be €12. This is because U2 can still provide 10 MW more of the implicit bundle at the price of €12.

Unit	(p, Q)	Incremental q [MW]
U1	(9,30)	30
U1	(10,50)	20
U2	(12,30)	30 Only 20 MW is allocated
U1	(12,60)	10
U2	(14,80)	50
U2	(16,120)	40
U1	(16,90)	30
U2	(19,200)	80

Step 2 for S1:

Now the residual merit order for individual service S1, can be obtained. We need to allocate 60 MW of S1 to U1 and 20 MW of S1 to U2.

Unit	(p, Q)	Incremental q [MW]
U3	(4,50)	50
~~U1~~	~~(5,50)~~	~~50~~
U3	(5,120)	70
U1	(7,~~100~~ 40)	~~50~~ 40
~~U2~~	~~(7,30,~~10)	~~30~~ 10
U2	(9,~~120~~ 100)	90
U1	(10,~~120~~ 60)	20
U2	(10,~~200~~ 180)	80
U1	(11,~~150~~,90)	30

Step 2 for S2:

Now the residual merit order for individual service S2, can be obtained by applying the same logic. We need to allocate 60 MW of S2 to U1 and 20 MW of S2 to U2.

Unit	(p, Q)	Incremental q [MW]
U4	(3,20)	20
~~U1~~	~~(4,30)~~	~~30~~
~~U1~~	~~(5,60)~~	~~30~~
~~U2~~	~~(5,80~~ 60)	~~80~~ 60
U4	(5,50)	30
U2	(7,~~120~~ 100)	40
U1	(9,~~90~~ 30)	30
U2	(9,~~200~~ 180)	80

Step 3 for S1:

The residual volume requirement is 120 MW for S1. It can be readily procured by allocating 120 MW to U3. Therefore, the marginal price for procuring an additional MW of S1 would be €7. This is because U1 can provide 40 MW of S1 at the price of €7.

Unit	(p,Q)	Incremental q [MW]
U3	(4,50)	50
~~U1~~	~~(5,50)~~	~~50~~
U3	(5,120)	70
U1	(7,~~100~~ 40)	~~50~~ 40
~~U2~~	~~(7,30)~~	~~30~~
U2	(9,~~120~~ 90)	90
U1	(10,~~120~~ 60)	20
U2	(10,~~200~~ 170)	80
U1	(11,~~150~~,90)	30

Step 3 for S2:

Gine the 150 MW requirement, the residual volume requirement is 70 MW for S2. This can be allocated to U4's first P-Q pair and partially allocate to U2's residual (5,60) pair. Therefore the marginal price of procuring S2 would be €5.

Unit	(p,Q)	Incremental q [MW]
U4	(3,20)	20
~~U1~~	~~(4,30)~~	~~30~~
~~U1~~	~~(5,60)~~	~~30~~
~~U2~~	(5,~~80~~ 60)	~~80~~ 60 Only 50 MW is allocated
U4	(5,50)	30
U2	(7,~~120~~ 100)	40
U1	(9,~~90~~ 30)	30
U2	(9,~~200~~ 180)	80

Step 4:

Based on the marginal prices calculated for each services at Step 3 (i.e., €7 for S1 and €5 for S2), the TSOs could procure additional individual services at a total cost of €12. The marginal price for the implicit bundle of services is also €12 assuming the optimal allocated volume for the bundle is 80 MW.

The difference of €12 and €12 is less than the TSOs willingness to pay which is set at €2 (the value function). Therefore, 80 MW assumption for the optimal volume of the bundle could be the optimal solution.

The question here is whether additional volume can be procured as the implicit bundle of services S1 & S2 while remaining compatible with the TSOs' value function, set at €2. To know the answer, we should repeat the 4 steps one more time. Let's suppose 89 MW is assumed as the optimal value for the bundle of S1 & S2.

8.2.5. Example 5) Continuing example 4 by revising the optimal implicit bundle to 89 MW

Step 1:

Suppose that TSOs procure 89 MW as the implicit bundle of S1 and S2.

The bundle supply functions per service provider were calculated as below.

Bundle supply function from U1: $\{(9,30),(10,50),(12,60),(16,90)\}$

Bundle supply function from U2: $\{(12,30),(14,80),(16,120),(19,200)\}$

Therefore, 89 MW can be allocated as below:

- 60 MW to U1 (offered at a price of €12 or higher); and
- 29 MW to U2 (offered at a price of €12 or higher).

There is an alternative here as follows:

- 59 MW to U1 (offered at a price of 12 € or higher); and
- 30 MW to U2 (offered at a price of 12 € or higher).

There would be no difference the resulting clearing prices between the two possible alternatives. For this analysis, we use the first alternative, which allocates 60 MW to U1 and 29 MW to U2.

Note: The result of the second alternative (allocating 59 MW to U1 and 30 MW to U2) can be found in Section 7.3 Alternatives below labelled as "Alternative 2".

To represent this allocation in the merit order for the implicit bundle of services (S1 & S2), the table below highlights the fully accepted increments in green and partially accepted increments in gold. Therefore, the clearing price for bundle of services is €12 and the marginal price would be €12. This is because U2 can still provide 1 MW more of the implicit bundle at the price of €12.

Unit	(p,Q)	Incremental q [MW]
U1	(9,30)	30
U1	(10,50)	20
U2	(12,30)	30 Only 29 MW is allocated
U1	(12,60)	10
U2	(14,80)	50
U2	(16,120)	40
U1	(16,90)	30
U2	(19,200)	80

Step 2 for S1:

Now the residual merit order for individual service S1, can be obtained. We need to allocate 60 MW of S1 to U1 and 29 MW of S1 to U2.

Unit	(p, Q)	Incremental q [MW]
U3	(4,50)	50
~~U1~~	~~(5,50)~~	~~50~~
U3	(5,120)	70
U1	(7,~~100~~ 40)	~~50~~ 40
~~U2~~	(7~~,30,~~1)	~~30~~ 1
U2	(9,~~120~~ 91)	90
U1	(10,~~120~~ 60)	20
U2	(10,~~200~~ 171)	80
U1	(11,~~150~~,90)	30

Step 2 for S2:

Now the residual merit order for individual service S2, can be obtained by applying the same logic. We need to allocate 60 MW of S2 to U1 and 29 MW of S2 to U2.

Unit	(p, Q)	Incremental q [MW]
U4	(3,20)	20
~~U1~~	~~(4,30)~~	~~30~~
~~U1~~	~~(5,60)~~	~~30~~
~~U2~~	~~(5,80~~ 51)	~~80~~ 51
U4	(5,50)	30
U2	(7,~~120~~ 91)	40
U1	(9,~~90~~ 30)	30
U2	(9,~~200~~ 171)	80

Step 3 for S1:

Given the 200 MW requirement for S1, the residual volume requirement is 111 MW. It can be readily procured by allocating 111 MW to U3. Therefore, the marginal price for procuring an additional MW of S1 would be €5. This is because U3 can still provide 9 MW more of the S1 at the price of €5.

Unit	(p,Q)	Incremental q [MW]
U3	(4,50)	50
~~U1~~	~~(5,50)~~	~~50~~
U3	(5,120)	70 Only 61 MW is allocated
U1	(7,~~100~~ 40)	~~50~~ 40
~~U2~~	(7~~,30,~~1)	~~30~~ 1
U2	(9,~~120~~ 91)	90
U1	(10,~~120~~ 60)	20
U2	(10,~~200~~ 171)	80
U1	(11,~~150~~,90)	30

Step 3 for S2:

The residual volume requirement is 61 MW for S2. This can be allocated to U4's first P-Q pair and partially allocate to U2's residual (5,60) pair. Therefore the marginal price of procuring S2 would be €5. This is because U2 can still provide 10 MW more of S2 at the price of €5.

Unit	(p,Q)	Incremental q [MW]
U4	(3,20)	20
~~U1~~	~~(4,30)~~	~~30~~
~~U1~~	~~(5,60)~~	~~30~~
~~U2~~	(5~~,80~~ 51)	~~80~~ 51 Only 41 MW is allocated
U4	(5,50)	30
U2	(7,~~120~~ 91)	40
U1	(9,~~90~~ 30)	30
U2	(9,~~200~~ 171)	80

Step 4:

Based on the marginal prices calculated for each service at Step 3 (i.e., €5 for S1 and €5 for S2), the TSOs could procure additional individual services at a total cost of €10. The marginal price for the implicit bundle of services is also €12 assuming the optimal allocated volume for the bundle is 89 MW.

The difference of €12 and €10 is equal to the TSOs' willingness to pay which is set at €2 (the value function). Therefore, 89 MW assumption for the optimal volume of the bundle is the optimal solution.

8.3. Alternatives

8.3.1. Alternative 1:

Now we assess the alternative allocation of the bundle to U1 and U2 as follows.

- 50 MW to U1 (offered at a price of €12 or higher); and
- 30 MW to U2 (offered at a price of €12 or higher).

To represent this allocation in merit order for the implicit bundle of service (S1 & S2), the table below highlights the fully accepted increments in green. Therefore, the clearing price for a bundle of services is €12 and the marginal price would be €12. This is because U1 can still provide 10 MW of the implicit bundle at the price of €12.

Unit	(p, Q)	Incremental q [MW]
U1	(9,30)	30
U1	(10,50)	20
U2	(12,30)	30
U1	(12,60)	10
U2	(14,80)	50
U2	(16,120)	40
U1	(16,90)	30
U2	(19,200)	80

Step 2 for S1:

Now the residual merit order for individual service S1, can be obtained. We need to allocate 50 MW of S1 to U1 and 30 MW of S1 to U2.

Unit	(p, Q)	Incremental q [MW]
U3	(4,50)	50
~~U1~~	~~(5,50)~~	~~50~~
U3	(5,120)	70
U1	(7,~~100~~ 50)	50
~~U2~~	~~(7,30)~~	~~30~~
U2	(9,~~120~~ 90)	90
U1	(10,~~120~~ 70)	20
U2	(10,~~200~~ 170)	80
U1	(11,~~150~~,100)	30

Step 2 for S2:

Now the residual merit order for individual service S2, can be obtained by applying the same logic. We need to allocate 50 MW of S2 to U1 and 30 MW of S2 to U2.

Unit	(p, Q)	Incremental q [MW]
U4	(3,20)	20
~~U1~~	~~(4,30)~~	~~30~~
~~U1~~	~~(5,60,~~ 10)	~~30~~ 10
~~U2~~	~~(5,80~~ 50)	~~80~~ 50
U4	(5,50)	30
U2	(7,~~120~~ 90)	40
U1	(9,~~90~~ 40)	30
U2	(9,~~200~~ 170)	80

Step 3 for S1:

The residual volume requirement is 120 MW for S1. It can be readily procured by allocating 120 MW to U3. Therefore, the marginal price for procuring an additional MW of S1 would be €7. This is because U2 can provide 50 MW of S1 at the price of €7.

Unit	(p, Q)	Incremental q [MW]
U3	(4,50)	50
~~U1~~	~~(5,50)~~	~~50~~
U3	(5,120)	70
U1	(7,~~100~~ 50)	50
~~U2~~	~~(7,30)~~	~~30~~
U2	(9,~~120~~ 90)	90
U1	(10,~~120~~ 70)	20
U2	(10,~~200~~ 170)	80
U1	(11,~~150~~,100)	30

Step 3 for S2:

The residual volume requirement is 70 MW for S2. This can be allocated to U4's first P-Q pair and partially allocate to U2's residual (5,60) pair. Therefore the marginal price of procuring S2 would be €5. This is because U2 can still provide 10 MW of S2 at the price of €5.

Unit	(p, Q)	Incremental q [MW]
U4	(3,20)	20
~~U1~~	~~(4,30)~~	~~30~~
~~U1~~	~~(5,60,~~ 10)	~~30~~ 10
~~U2~~	(5,~~80~~ 50)	~~80~~ 50 Only 40 MW is allocated
U4	(5,50)	30
U2	(7,~~120~~ 90)	40
U1	(9,~~90~~ 40)	30
U2	(9,~~200~~ 170)	80

Step 4:

Based on the marginal prices calculated for each services at Step 3 (i.e., €7 for S1 and €5 for S2), the TSOs could procure additional individual services at a total cost of €12. The marginal price for the implicit bundle of services is also €12 assuming the optimal allocated volume for the bundle is 80 MW.

The difference of €12 and €12 is less than the TSOs willingness to pay which is set at €2 (the value function). Therefore, 80 MW assumption for the optimal volume of the bundle could be the optimal solution.

The question here is whether additional volume can be procured as the implicit bundle of services S1 & S2 while remaining compatible with the TSOs' value function, set at €2. To know the answer, we should repeat the 4 steps one more time.

8.3.2. Alternative 2:

Now we assess the alternative as below:

- 59 MW to U1 (offered at a price of 12 € or higher); and
- 30 MW to U2 (offered at a price of 12 € or higher).

To represent this allocation in merit order for the implicit bundle of service (S1 & S2), the table below highlights the fully accepted increments in green and partially accepted increments in gold. Therefore, the clearing price for bundle of services is €12 and the marginal price would be €12. This is because U1 can still provide 1 MW more of the implicit bundle at the price of €12.

Unit	(p, Q)	Incremental q [MW]
U1	(9,30)	30
U1	(10,50)	20
U2	(12,30)	30
U1	(12,60)	10 Only 9 MW is allocated
U2	(14,80)	50
U2	(16,120)	40
U1	(16,90)	30
U2	(19,200)	80

Step 2 for S1:

Now the residual merit order for individual service S1, can be obtained. We need to allocate 59 MW of S1 to U1 and 30 MW of S1 to U2.

Unit	(p, Q)	Incremental q [MW]
U3	(4,50)	50
~~U1~~	~~(5,50)~~	~~50~~
U3	(5,120)	70
U1	(7,~~100~~ 41)	~~50~~ 41
~~U2~~	~~(7,30)~~	~~30~~
U2	(9,~~120~~ 90)	90
U1	(10,~~120~~ 61)	20
U2	(10,~~200~~ 170)	80
U1	(11,~~150~~,91)	30

Step 2 for S2:

Now the residual merit order for individual service S2, can be obtained by applying the same logic. We need to allocate 59 MW of S2 to U1 and 30 MW of S2 to U2.

Unit	(p, Q)	Incremental q [MW]
U4	(3,20)	20
~~U1~~	~~(4,30)~~	~~30~~
~~U1~~	(5,~~60~~ 1)	~~30~~ 1
~~U2~~	~~(5,80~~ 50)	~~80~~ 50
U4	(5,50)	30
U2	(7,~~120~~ 90)	40
U1	(9,~~90~~ 31)	30
U2	(9,~~200~~ 170)	80

Step 3 for S1:

The residual volume requirement is 111 MW for S1. It can be readily procured by allocating 111 MW to U3. Therefore, the marginal price for procuring an additional MW of S1 would be €5. This is because U3 can still provide 9 MW more of S1 at the price of €5.

Unit	(p, Q)	Incremental q [MW]
U3	(4,50)	50
~~U1~~	~~(5,50)~~	~~50~~
U3	(5,120)	70 Only 61 MW is allocated
U1	(7,~~100~~ 41)	~~50~~ 41
~~U2~~	~~(7,30)~~	~~30~~
U2	(9,~~120~~ 90)	90
U1	(10,~~120~~ 61)	20
U2	(10,~~200~~ 170)	80
U1	(11,~~150~~,91)	30

Step 3 for S2:

The residual volume requirement is 61 MW for S2. This can be allocated to U4's first P-Q pair and partially allocate to U2's residual (5,80) pair. Therefore the marginal price of procuring S2 would be €5. This is because U2 can still provide 10 MW more of S2 at the price of €5.

Unit	(p, Q)	Incremental q [MW]
U4	(3,20)	20
~~U1~~	~~(4,30)~~	~~30~~
~~U1~~	(5,~~60~~ 1)	~~30~~ 1
~~U2~~	(5,~~80~~ 50)	~~80~~ 50 Only 40 MW is allocated
U4	(5,50)	30
U2	(7,~~120~~ 90)	40
U1	(9,~~90~~ 31)	30
U2	(9,~~200~~ 170)	80

Step 4:

Based on the marginal prices calculated for each services at Step 3 (i.e., €5 for S1 and €5 for S2), the TSOs could procure additional individual services at a total cost of €10. The marginal price for the implicit bundle of services is also €12 assuming the optimal allocated volume for the bundle is 89 MW.

The difference of €12 and €10 is equal to the TSOs' willingness to pay which is set at €2 (the value function). Therefore, 89 MW assumption for the optimal volume of the bundle is the optimal solution.