



Review of the SEM CRM and Design of CRM 2.0

A report to the SEM Committee

JUNE 2026



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1 Executive Summary

This report sets out the findings of a strategic review of the SEM CRM, as well as the proposed design options for the areas prioritised through the review.

The review is based on an assessment of the CRM in terms of:

1. its compliance with the current EU legislative and State aid framework;
2. the challenges that have arisen with the CRM to date; and
3. the development needs from a forward-looking perspective as the Irish and Northern Irish energy sectors transition to net zero.

State aid approval for the current CRM in the SEM will expire in May 2028 and a new approval will be sought in advance of this. The design that will be submitted to the European Commission for State aid approval is referred to as “CRM 2.0” throughout this report. The review, presented in Sections 4-9 of this report, identifies and prioritises areas where development of the existing mechanism should be progressed for inclusion in the CRM 2.0 design, while also recommending areas for potential development in the longer term.

Sections 10-15 of this report then set out the proposed design options for those areas prioritised through the review. The timeline for development of the design options is constrained by the target date for submission of the new State aid application of H1 2027. This relatively tight timeframe influences the recommendations in this report regarding the development to the CRM design.

The second key consideration influencing our approach, and the magnitude of the changes we consider, is the stage of the energy transition that the SEM is at i.e. with the Flexibility Needs Assessment(s) currently in development and with technologies for substantial decarbonisation of dispatchable capacity not yet available for deployment at scale.

In addition, we make two key assumptions, that:

1. The adequacy need to justify a new State aid approval will be demonstrated in the 2027-2036 All-Island Resource Adequacy Assessment, and
2. The accompanying 2027-2036 Economic Viability Assessment will support the need for a *market-wide* mechanism like the SEM CRM.

Based on these considerations and assumptions, the philosophy that we adopt in the review is as follows:

1. “**Evolution, not revolution**”: CRM 2.0 should be an evolution of the current CRM, rather than a radically changed mechanism.
2. A **dynamic approach to State aid approval** should be taken, allowing continued evolution of the CRM over the lifetime of the next State aid approval by:
 - a. building flexibility into the State aid approval where possible and useful, and
 - b. planning for development of the CRM during the 10-year period even where State aid renotification is required.

The review has been informed by the following inputs:

- an analysis of modifications to the current CRM over the course of its lifetime;
- previous assessments of the CRM;
- substantial engagement with a range of internal and external stakeholders;
- a review of the underpinning EU framework and of the policy landscape across the island of Ireland; and
- the TSOs' adequacy and scenario analysis.

Of the development needs identified, those driven by compliance requirements are given highest priority – though noting that these align with the needs identified based on the future development of the electricity system – along with those challenges with the CRM to date which have been most impactful. This suite of prioritised changes constitutes the scope of the design work to be progressed in time for inclusion in the State aid application in H1 2027.

We also, however, give consideration to more strategic design changes that may be pertinent in the future, potentially requiring State aid “renotification”. These are areas where we expect the case for change may become stronger over time and/or where the magnitude of the change makes design development within the State aid approval timeframe unfeasible.

Finally, we identify a set of smaller-scale changes to the design that could be beneficial, but that we do not view as likely to warrant notification to the European Commission, and that as such can be progressed independent of the State aid timeline if so desired.

These different “pots” of changes are illustrated in Figure 1. Focussing on those issues that we recommend be prioritised for inclusion in the State aid application in H1 2027 (Pots 1 and 2), we leave “explicit cross-border participation” aside, as the work to implement this is already in progress separately, and then consolidate similar issues to produce a set of six work areas in which we proceed to develop design options. These work areas or “design elements” are illustrated in Figure 2.

In respect of the **delivery timeframe**, we recommend a move to a T-5 timeframe as standard for the main auctions under the CRM 2.0 State aid approval. The top up auction should remain a T-1 as standard, with volumes to be reserved for this auction up to 25% of the T-5 capacity requirement. We also advise that the optimal timeframe for delivery of battery storage should be kept under review in case an intermediate timeframe may be better suited to this technology type.

In regard to enhancing the **availability incentives**, we propose that a supplementary mechanism to the RO be established. This would be targeted at periods of scarcity not covered by the RO, and associated with a lower financial exposure than the RO. The trigger would either be the price in the energy market, set at a lower level than the RO strike price, or a measure of margin, set at a lower threshold than in the case of ASP. Aligned with the CISAF approach to identifying the customers contributing to the need for the CRM (i.e. those consuming during the 1-5% of highest priced hours), we consider that the trigger threshold should be set to target this proportion of hours.

Relatedly, we consider that a unit-specific **DRF methodology** applied to all technology types would have benefits in terms of the availability incentive it creates, as well as being in line with the EU's CISAF target model for market wide capacity

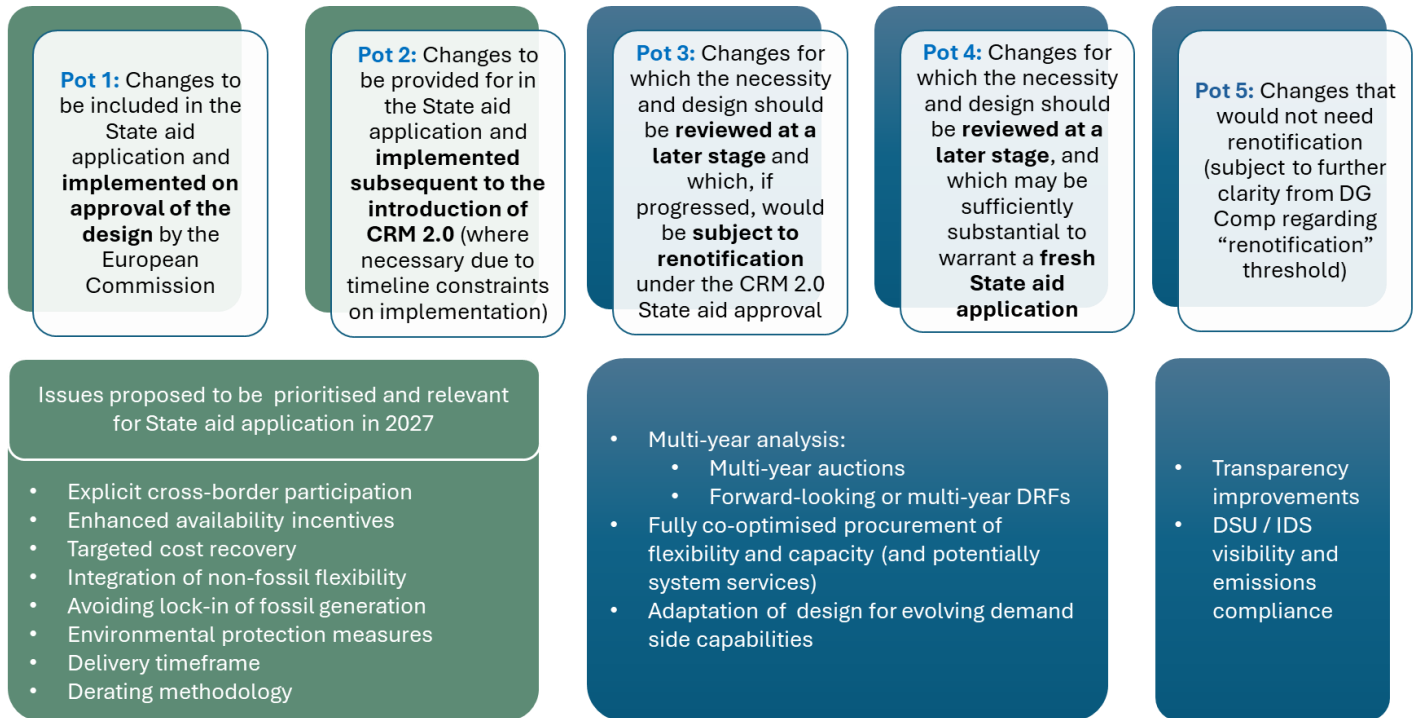
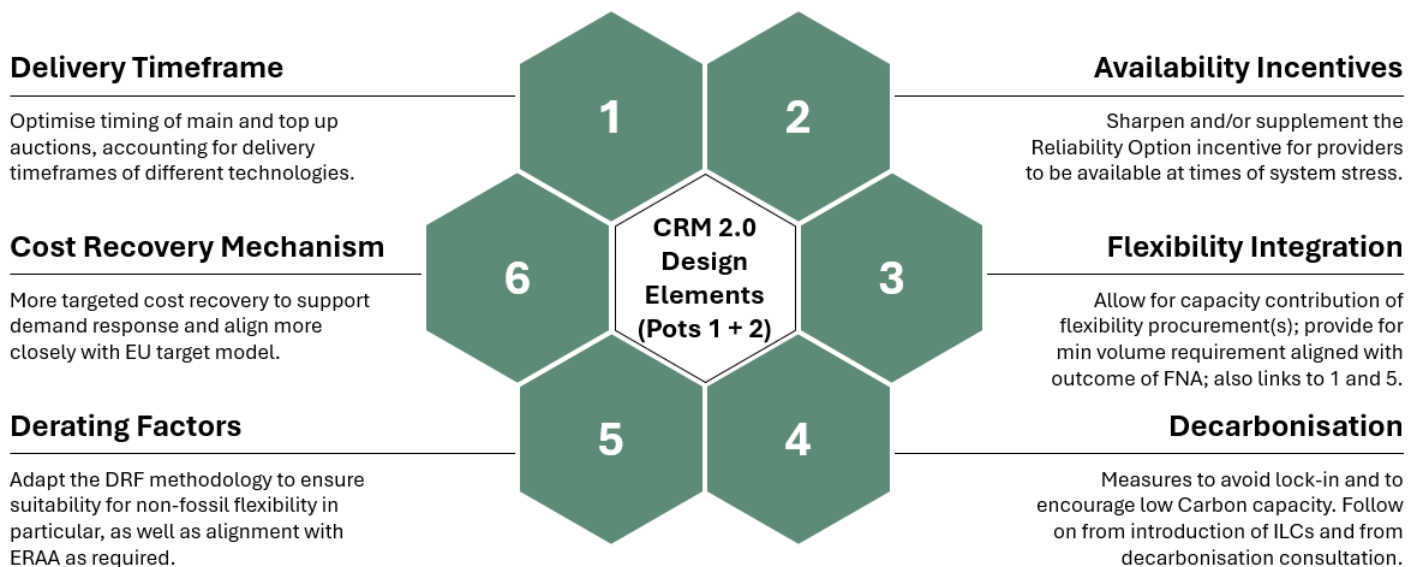
mechanisms by allowing the DRF of individual providers to vary. We also consider that this type of methodology is particularly appropriate for non-fossil flexibility because the variation in availability across units in a given technology class is greatest in the case of demand response and storage. We note however that this approach to derating would interact with the supplementary availability incentive proposed, and it would be important to consider whether unavailability was being double-counted through both charges for non-availability and being factored into the setting of a unit-specific DRF. The design of the unit-specific methodology will need to be considered further as the TSOs' initial impact assessment and new DRF tool are developed. We suggest that a dedicated consultation may be appropriate, allowing this element of the CRM Development Programme to progress to a separate timeline to the other elements.

We consider that a more temporally targeted approach to **cost recovery** would be beneficial from an economic perspective, as well as being more forward-looking in terms of encouraging consumers to engage with their electricity consumption. We also note that it is likely to be an important aspect of the State aid application and an area of focus for the European Commission. We propose two alternative options. Firstly, the costs could be targeted at the upper end of the range specified in CISAF i.e. at 5% of the highest priced periods. Alternatively, in light of the current status of the smart metering roll-out across the SEM, a glide path could be followed, beginning with a move to 25% of the highest priced hours. Once smart metering is more fully rolled out, the cost recovery window would be narrowed further in line with the CISAF requirement.

As a means of future-proofing CRM 2.0 for potential developments in the framework for procurement of non-fossil flexibility, we recommend including the following two provisions in the State aid application for **flexibility integration**:

1. Where a separate NFFSS is established in future, capacity contracted under that NFFSS will in general not be allowed to participate in CRM 2.0. The capacity requirement in the CRM auctions will be adjusted to reflect the capacity contribution of the flexible resources procured through the NFFSS. However, some flexibility should be retained to consider the approach on a case-by-case basis as there could be circumstances, depending on the nature of the NFFSS, where it may make sense to allow dual participation, provided the risks of overcompensation and project termination are avoided.
2. Where non-fossil flexibility needs are identified on an all-island basis that require new investment not incentivised through a dedicated NFFSS, a constraint can be applied to the CRM auctions to ensure that the capacity procured also satisfies those flexibility needs.

With the aim of future-proofing the design of CRM 2.0 to facilitate **decarbonisation**, we propose that provision be made in the State aid application for the introduction of a Green Scalar if the technology and policy context evolve such that the scalar would materially incentivise the development of low carbon technologies. The Green Scalar would be set so as to reflect the additional Capex costs associated with a low carbon Best New Entrant technology. It would only impact the price paid to the eligible low carbon technology and not that paid to other capacity, and it would only do this where the clearing price of the auction was less than the bid price of the technology concerned multiplied by the Green Scalar. Technologies would be eligible for the Green Scalar where their specific CO₂ emissions were zero (or very close to zero), and where the value of the carbon emissions they would displace on the system exceeded the additional cost of support through the CRM.

Figure 1: Development needs of the CRM identified in this review.

Figure 2: Elements of the design phase of CRM 2.0.


2 Glossary

| Abbreviation | Definition |
|--------------|--|
| ACER | Agency for the Cooperation of Energy Regulators |
| AIRAA | All-Island Resource Adequacy Assessment |
| BECCS | Bioenergy with Carbon Capture and Storage |
| BESS | Battery Energy Storage System |
| BNE | Best New Entrant |
| CAP | Climate Action Plan |
| CCUS | Carbon Capture, Use and Storage |
| CCU | Carbon Capture and Utilization |
| CEEAG | Climate, Energy and Environmental Aid Guidelines |
| CEP | Clean Energy Package |
| CfD | Contract for Difference |
| CISAF | Clean Industrial Deal State Aid Framework |
| CMC | Capacity Market Code |
| CMU | Capacity Market Unit |
| CONE | Cost of New Entry |
| CRM | Capacity Remuneration Mechanism |
| DASSA | Day-Ahead System Services Auction |
| DG Comp | Directorate-General for Competition |
| DPA | Dispatchable Power Agreement |
| DRF | Derating Factor(s) |
| DSU | Demand Side Unit |
| DS3 | 'Delivering a Secure Sustainable Electricity System': principally the ancillary service regime |
| EC | European Commission |
| EEAG | Guidelines on State aid for environmental protection and energy |
| ERAA | European Resource Adequacy Assessment |
| EU | European Union |
| EVA | Economic Viability Assessment |
| FASS | Future Arrangements System Services |
| FiT | Feed in Tariff |

| | |
|---------------|---|
| FNA | Flexibility Needs Assessment |
| GB | Great Britain |
| GCS | Generation Capacity Statement |
| GHG | Greenhouse Gas Emissions |
| HVO | Hydrotreated Vegetable Oil |
| IDS | Individual Demand Site |
| ILC | Intermediate Length Contract |
| INCTOL/DECTOL | Increase tolerance and Decrease tolerance |
| I-SEM | Integrated Single Electricity Market |
| IT | Information Technology |
| LDES | Long-Duration Energy Storage |
| LEU | Large Energy Users |
| LOLE | Loss Of Load Expectation |
| NESO | National Energy System Operator |
| NI | Northern Ireland |
| NPV | Net Present Value |
| NRAA | National Resource Adequacy Assessment |
| PTE | Panel of Technical Experts |
| RA | Regulatory Authorities |
| RESS | Renewable Energy Support Scheme |
| RO | Reliability Option |
| RPP | Risk Preparedness Plan |
| RS | Reliability Standard |
| SEM | Single Electricity Market |
| SEMC | Single Electricity Market Committee |
| SONI | System Operator for Northern Ireland |
| TEG | Temporary Emergency Generation |
| TES | Tomorrow's Energy Scenarios |
| TSO | Transmission System Operator |
| USPC | Unit-Specific Price Cap |
| VOLL | Value of Lost Load |

3 Introduction

AFRY has been engaged by the RAs to support in the development of the SEM Capacity Remuneration Mechanism (CRM) and with the associated State aid process.

State aid approval for the current CRM in the SEM will expire in May 2028 and a new State aid approval will be sought in advance of this. The target timeline for this programme includes submission of the new State aid application in the first half of 2027, with approval from the European Commission to follow in the second half of 2027. The design that will be submitted to the European Commission for State aid approval will be referred to as “CRM 2.0” throughout this report.

We have been requested to carry out a strategic review of the CRM, to identify areas where development may be required, and to develop design options for consultation, and ultimately implementation, in the context of the new State aid approval.

Sections 4-9 of this report constitute a high-level review of the SEM CRM, with the objective of identifying the areas where development should be progressed to the existing mechanism design. Sections 10-15 contain the design recommendations in each of the areas identified through the review.

The timeline for development of the design options is constrained by the requirement to submit the new State aid application in H1 2027. With a target date of July 2026 for publication of a consultation on these design options, there are 6 months in which to progress from design proposals to decisions. This is a relatively tight timeframe, and one which influences the recommendations we make in this review regarding the areas to develop in the CRM design.

The second key consideration influencing our approach, and the magnitude of the changes we consider, is the stage of the energy transition that the SEM is at i.e. with the Flexibility Needs Assessment(s) currently in development and with technologies for substantial decarbonisation of dispatchable capacity not yet available for deployment at scale.

In addition, we make two key assumptions:

1. That the adequacy need required to justify a new State aid approval will be demonstrated in the TSOs’ 2027-2036 All-Island Resource Adequacy Assessment, and
2. That the accompanying 2027-2036 Economic Viability Assessment will support the need for a *market-wide* mechanism like the SEM CRM.

Based on these considerations and assumptions, the philosophy that we adopt in this review and design process is as follows:

3. **“Evolution, not revolution”**: CRM 2.0 should be an evolution of the current CRM, rather than a radically changed mechanism.
4. A **dynamic approach to State aid approval** should be taken, allowing continued evolution of the CRM over the lifetime of the next State aid approval by:
 - c. building flexibility into the State aid approval where possible and useful, and
 - d. planning for development of the CRM during the 10-year period even where State aid renotification is required.

The review examines the CRM through the three lenses shown in Figure 3, considering compliance requirements, the performance of the CRM to date, and the expected future development of the electricity system. It is informed by:

- An analysis of modifications to the Capacity Market Code since 2018
- The conclusions of the 2022 EY Review
- Regular engagement, and a dedicated workshop, with the RA teams
- An informal workshop with the TSOs
- An in-person industry workshop
- A review of relevant EU legislation and State aid guidelines
- Engagement with DG Comp, DCEE and DfE
- An analysis of the policy landscape in Ireland and Northern Ireland
- AIRAA 2026-2035
- Tomorrow’s Energy Scenarios 2023

The development needs identified are prioritised, with those driven by compliance requirements given highest priority – though noting that these align with the needs identified based on the future development of the electricity system – along with those issues with the CRM to date which have been most impactful. We also consider more strategic design changes that may be pertinent in the future, potentially requiring “renotification” of the CRM under the CRM 2.0 approval, or a fresh State aid application.

Finally, we identify a set of smaller-scale changes to the design that could be beneficial, but that we do not view as likely to warrant notification to the European Commission, and that as such can be progressed by the SEM Committee independent of the State aid timeline if so desired. These different “pots” of changes are illustrated conceptually in Figure 4.

On the basis of this review, we set out design proposals for those areas prioritised for development, in order that these may underpin the planned consultation process.

Figure 3: The three lenses through which the SEM CRM is examined in this review.

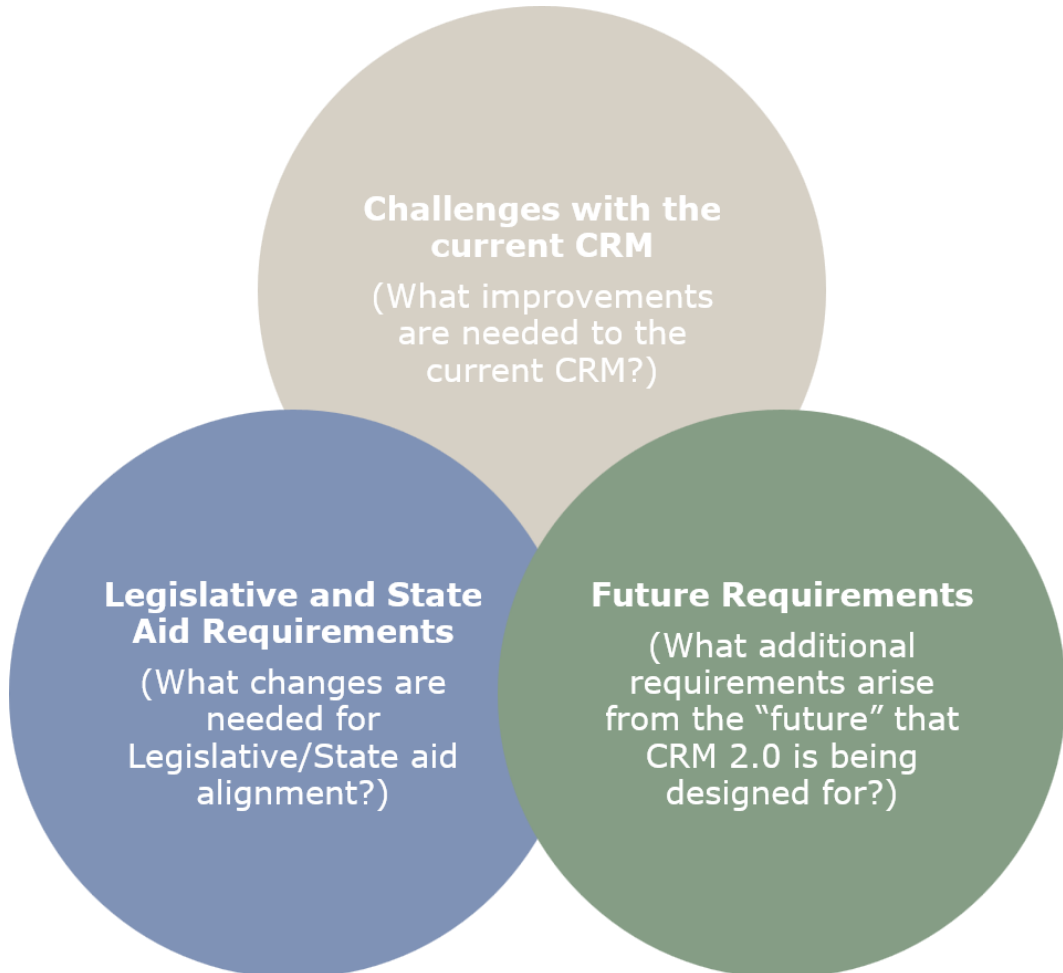
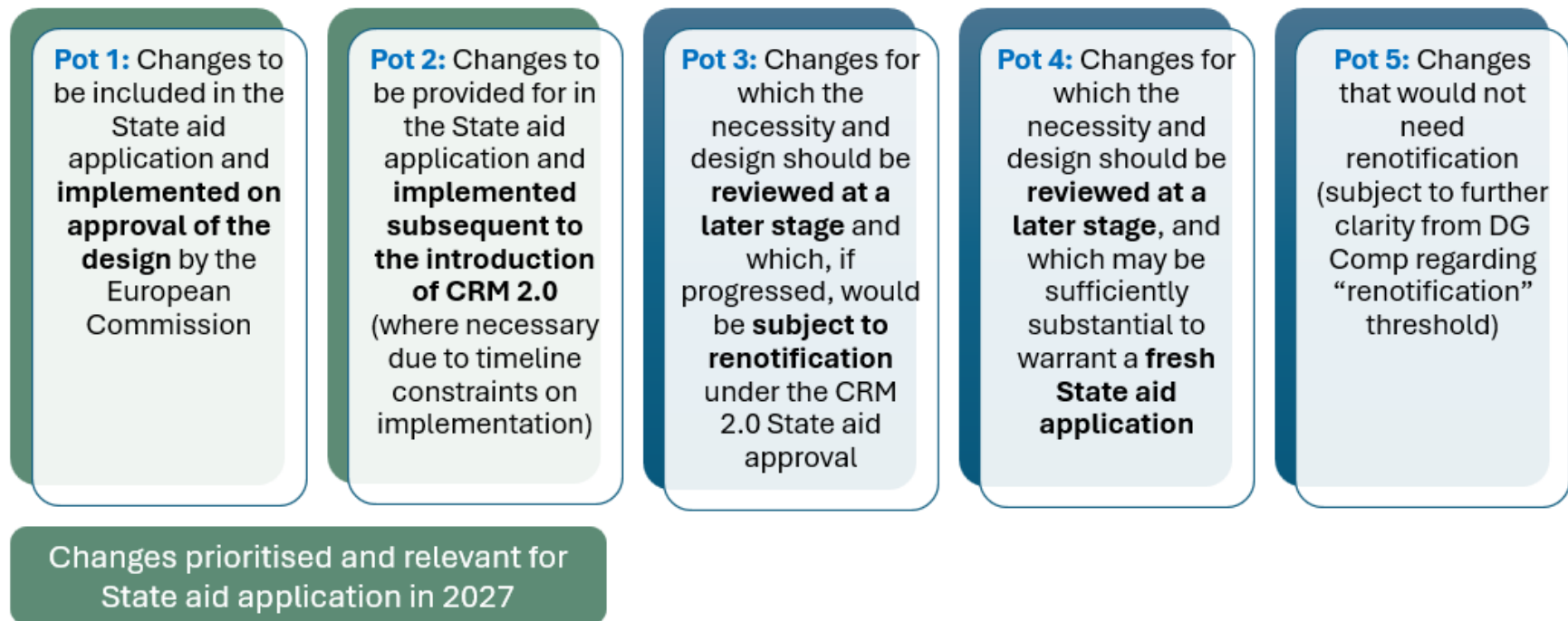


Figure 4: Different pots into which proposed design changes are categorised in this review.



4 Review: Objectives of CRM 2.0

The objectives of CRM 2.0, as set out in Table 1, have been developed based on discussions with the RA CRM teams and on previous market design work carried out by AFRY. They are aligned with the assessment criteria applied during the development of the I-SEM High Level Design, and of the current CRM design, as well as with the SEM Committee’s new Strategy. While there are three primary objectives shown, we consider that Security of Supply is the foremost objective of any Capacity Mechanism.

Table 1: Objectives and compliance requirements of CRM 2.0.

| Primary Objectives | Secondary Objectives | Compliance Requirements |
|--|---|---|
| 1. Ensuring Security of Supply by: <ul style="list-style-type: none"> — Securing adequate capacity — Incentivising investment in reliable and flexible resources | Practical , relating to ease of: <ul style="list-style-type: none"> — Implementation — Ongoing operation — Market participation — Low transaction costs | Compliance with EU (and domestic) legislation and State aid guidelines, in particular: <ul style="list-style-type: none"> — Electricity Regulation (2019) — Electricity Regulation (2024) — CEEAG (noting that CISAF compliance is not a hard constraint) |
| 2. Cost efficient provision by: <ul style="list-style-type: none"> — Maximising socio-economic welfare — Promoting efficient use of resources — Avoiding over-procurement and market distortion — Fostering competition | Investable <ul style="list-style-type: none"> — Respecting existing investments — Providing sufficient incentives for efficient future investments | |
| 3. Supporting the transition to a net zero system by: <ul style="list-style-type: none"> — Promoting low-carbon technologies — Incentivising flexibility | Market-Oriented <ul style="list-style-type: none"> — Transparent — Low barriers to entry — Technology neutral — Minimum regulatory risk Enduring (stable) <ul style="list-style-type: none"> — Suitable/adaptable to future challenges — Well understood change governance | |

5 Review: Legislative and State Aid Requirements

The legislative framework underpinning the CRM is provided by EU electricity market legislation and the associated State aid guidelines. In this section, we set out the requirements stemming from this framework and identify the CRM development needs arising at this time. We examine the CRM through the following lens:



5.1 EU legislation

5.1.1 Regulation (EU) 2019/943

The Clean Energy Package was introduced in 2019, which included a new framework for identifying and addressing capacity adequacy needs.

Regulation (EU) 2019/943 (the “Electricity Regulation”) provided for the development and implementation of a new standardised methodology for the calculation of the key adequacy parameters: VoLL / CoNE / RS¹. ACER’s **VoLL / CoNE / RS methodology** was implemented in SEM in 2023².

The Electricity Regulation also provided for a new and standardised methodology for adequacy assessment, the **European Resource Adequacy Assessment methodology**³. This methodology is being implemented in stages by the TSOs in SEM as of 2024⁴, while continuing to be developed at EU level.

¹https://acer.europa.eu/sites/default/files/documents/Decisions_annex/ACER%20Decision%2023-2020%20on%20VOLL%20CONE%20RS%20-%20Annex%20I.pdf

² [Calculation of a single Value of Lost Load within the SEM Information Paper SEM-23-072.pdf](#)

³ [ACER Decision 24-2020 on ERAA - Annex I](#)

⁴ [All-Island Resource Adequacy Assessment 2025-2034](#)

Alongside these two methodologies, the Electricity Regulation set out **general principles** to apply in respect of Capacity Mechanisms. The full list of these principles is given in Annex A, with the key elements summarised here:

- Capacity Mechanisms were to be implemented as a “*last resort*” and to be “*temporary*”;
- The option of Strategic Reserve is to be assessed prior to implementing an alternative type of Capacity Mechanism; and
- Capacity Mechanisms are not to be introduced where both the ERAA and the NRAA have not identified an adequacy concern.

The Electricity Regulation also set out **design principles** for Capacity Mechanisms. These are also set out in full in Annex B, with key components listed here:

- Capacity providers are to be selected by means of a transparent, non-discriminatory and competitive process;
- Remuneration must be determined through a competitive process;
- There must be incentives for capacity providers to be available at times of expected system stress;
- Appropriate penalties must be applied to capacity providers that are not available at times of system stress;
- Capacity mechanisms must be open to participation of all resources capable of providing the required performance (i.e. be technology-neutral); and
- Payments under capacity mechanisms are restricted to generation capacity that does not exceed certain specified CO₂ emissions limits.

Where the capacity mechanism is not Strategic Reserve, additional principles apply, in that such mechanisms must:

- be constructed so as to ensure that the price paid for availability automatically tends to zero when the level of capacity supplied is expected to be adequate to meet the level of capacity demanded;
- remunerate the participating resources only for their availability and ensure that the remuneration does not affect decisions of the capacity provider on whether or not to generate;
- ensure that capacity obligations are transferable between eligible capacity providers.

In addition, the Electricity Regulation mandates that capacity mechanisms shall be open to direct cross-border participation of capacity providers located in another Member State.

In 2019 the SEM Committee assessed compliance of the CRM with the Electricity Regulation⁵ and concluded that the design was already compliant in many areas. The two principal areas identified as requiring development were:

1. The imposition of the specified CO₂ emissions limits; and
2. Progression of cross-border participation in the CRM.

The CMC was subsequently modified to introduce CO₂ limits to be imposed on capacity receiving payments⁶. Cross-border CRM participation is currently being progressed⁷.

Our assessment at this time aligns with that carried out in 2019, in that the current CRM design is generally compliant with the CEP principles (taking into account the work ongoing to implement explicit cross-border participation). Given the experience of the operation of the CRM since the time of the original CEP compliance review however, we believe there is one further area that warrants consideration. This is the requirement for there to be incentives for capacity providers to be available at times of expected system stress / appropriate penalties applied to capacity providers that are not available at times of system stress. While the SEM RO in principle meets these requirements, in practice it appears to have fallen short.

The number and total duration of RO events over the period 2022-2024 is shown in Table 2 below, compared with the number and duration of amber alerts issued by the TSOs due to tight capacity margins. It is clear that tight system margins are not reflected in wholesale market pricing in a way that incentivises RO holders to be available at times of system stress. It is important to note that all system alerts over this period were jurisdictional i.e. specific to either Ireland or Northern Ireland. This means that the administered scarcity pricing mechanism will not trigger, as it requires scarcity to be present on an all-island basis rather than a jurisdictional one.

⁵ https://www.semcommittee.com/files/semcommittee/media-files/SEM-19-073%20Roadmap%20to%20Clean%20Energy%20Package%20Implementation_0.pdf

⁶ https://www.sem-o.com/rules-and-modifications/capacity-market-modifications?mod_id=cmc_05_20&title=&mod_stage=All&mod_status=All&mod_section_affected=All

⁷ [SEM-25-071 Explicit Cross-Border Participation Consultation | The Single Electricity Market Committee](#)

Table 2: Number and duration of RO events compared with number and duration of system alerts.

| Year | 2022 | 2023 | 2024 |
|---|------|------|------|
| RO events | 2 | 0 | 3 |
| Total duration of RO events / hrs | 2.5 | 0 | 4.5 |
| System alerts | 8 | 3 | 7 |
| Total duration of system alerts / hrs | 49.5 | 11.5 | 80.5 |
| RO periods as a % of system alert periods | 5% | 0% | 6% |

5.1.2 Regulation (EU) 2024/1747

In 2024, the Electricity Market Reform package was introduced, prompted by the electricity price and security of supply impacts of geopolitical tension stemming from Russia’s invasion of Ukraine. This package included Regulation (EU) 2024/1747, which amended the existing Electricity Regulation. The amendments to the Electricity Regulation changed the European Commission’s stance on capacity mechanisms, with them no longer being classified as “*temporary*” or “*last resort*” (albeit that the State aid approval is still limited to ten years).

In addition, a new chapter was introduced into the Electricity Regulation, covering “*specific investment incentives to achieve the union’s decarbonisation objectives*”. The importance of flexible capacity to decarbonisation is recognised, with specific provision for Non-fossil Flexibility Support Schemes and a requirement for Member States to carry out a Flexibility Needs Assessment (FNA), similar in principle to the ERAA, and to establish an indicative national objective for non-fossil flexibility based on that assessment. Member States that apply a capacity mechanism shall:

“consider adapting the design of these mechanisms to promote the participation of non-fossil flexibility such as demand side response and energy storage...”

While the Electricity Regulation already required that capacity mechanisms be open to participation of all resources “*including energy storage and demand side management*”, the Electricity Market Reform has strengthened this requirement and effectively encourages Member States to actively

promote these technologies in their capacity mechanisms. The provision for Non-Fossil Flexibility Support Schemes and establishment of the FNA shifts the landscape in which the CRM operates towards flexible capacity and signals the role of flexibility in ensuring adequacy, which the CRM design must be cognisant of.

5.2 State Aid Requirements

The existing State aid approval was granted under the EEAG guidelines⁸ in force at that time. The new CEEAG guidelines⁹ were introduced in 2022 and sought to align the EU's State Aid framework with the European Green Deal. CEEAG have recently been complemented by the CISAF framework¹⁰, implemented in accordance with the Electricity Market Reform, with the aim of streamlining the process of obtaining State aid approval for capacity mechanisms, provided their design aligns with a defined "Target Model".

5.2.1 CEEAG

Environmental protection

The CEEAG guidelines in respect of "aid for the security of electricity supply", place a greater emphasis on environmental protection than the EEAG. This objective generally manifests in CEEAG in the form of provisions that encourage or facilitate, rather than obligate, measures to support environmental protection:

326/7. "aid measures aimed at increasing the security of electricity supply may also be designed to support environmental protection objectives"

*345. Member States are **encouraged** to introduce additional criteria or features in their security of supply measures to promote the participation of greener technologies (or reduce the participation of polluting technologies) necessary to support the delivery of the Union's environmental protection objectives."* [emphasis added]

However, there is a *requirement* on Member States to explain, where investment in new gas-fired generation is to be incentivised by the aid, how lock-in of this generation will be avoided:

*"369. ...Member States **must** explain how a lock-in of this gas-fired energy generation will be avoided. For example, this may include binding commitments by the beneficiary to implement decarbonisation technologies such as CCS/CCU or replace natural gas with renewable or low-carbon gas or to close the plant on a timeline consistent with the Union's climate targets."* [emphasis added]

⁸ [Communication from the Commission — Guidelines on State aid for environmental protection and energy 2014-2020](#)

⁹ [2022 guidelines on State aid for climate, environmental protection and energy | EUR-Lex](#)

¹⁰ https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=OJ:C_202503602

And while the principle of technology-neutrality set out in the Electricity Regulation is explicitly echoed in CEEAG, participation limits associated with environmental protection are considered appropriate:

“343. The aid measure should be open to all beneficiaries or projects technically capable of contributing efficiently to the achievement of the security of supply objective. This includes generation, storage and demand response, as well as the aggregation of small units of these forms of capacity into larger blocks.

344. Limitations on participation in security of supply measures that aim to ensure those measures do not undermine environmental protection are deemed appropriate.”

In addition, in its assessment of the State aid application, the European Commission will take account of:

“(b) [the Member State’s] assessment of the impact of demand-side and storage participation, including a description of measures to encourage demand side management”.

Interaction of the Capacity Mechanism with the Energy Market

CEEAG also includes specific requirements related to minimising the impact of the security of supply measure on the energy market. These generally echo the principles set out in the Electricity Regulation, but of note are the following:

The recipients of aid for resource adequacy should have incentives to “contribute” to security of supply via penalties derived from the imbalance settlement price:

“The beneficiaries of security of supply measures should have efficient incentives to contribute to security of supply during the delivery period. These incentives should in general be related to the value of lost load (VOLL). For example, where a beneficiary is not available, they should face a penalty related to VOLL. Other than for network congestion measures, this penalty should in general come from electricity imbalance settlement prices to avoid distortions to market functioning.”

The costs of the security of supply measure are to be targeted at those market participants contributing to the need for the measure:

“To avoid undermining incentives for demand response and exacerbating the market failures that lead to the need for security of supply measures, and to ensure the security of supply intervention is as limited in size as possible, the costs of a security of supply measure should be borne by the market participants who contribute to the need for the measure.”

5.2.2 CISAF

CISAF sets out how Member States can design State aid measures to support their objectives under the Clean Industrial Deal. This framework complements the CEEAG.

Non-Fossil Flexibility

CISAF provides guidance on support schemes for non-fossil flexibility, following on from the Electricity Market Reform package, and on the interaction of non-fossil flexibility procurement with Capacity Mechanisms. It prescribes that capacity and non-fossil flexibility measures should be coordinated in one of three ways:

“If a capacity mechanism is implemented in the Member State concerned, the design of this capacity mechanism should be open to the participation of non-fossil flexibility such as demand response and storage in this capacity mechanism. In addition, the capacity mechanism and non-fossil flexibility measures should be coordinated in one of the following ways to avoid creating market barriers and overcompensation:

- a) capacity should be jointly procured; or*
- b) Member States may include non-fossil flexibility requirements identified in the flexibility needs assessment in their capacity mechanisms, for example requiring a minimum volume of non-fossil flexible capacity providing short term ramping services; or*
- c) resources must choose between participating in only one measure, either the non-fossil flexibility support scheme or the capacity mechanism. The target demand in each measure should be adjusted to take account of participation in the other measure.”*

Target Model

CISAF also defines for the first time, a target model for Capacity Mechanisms in the form of both strategic reserve and a market wide mechanism, Annex C. It provides for an expedited State aid approval process where the Capacity Mechanism complies with all criteria defined within the relevant target model¹¹. Where some of the target model criteria are not met, the State aid assessment “might” need to be carried out under the CEEAG. However:

“within any assessment of capacity mechanisms under the CEEAG, compatibility can be assumed for any specific aspects of a strategic reserve or central buyer market wide capacity mechanism that meet the criteria [in the applicable target model].”

This implies that compatibility of the Capacity Mechanism with the requirements of EU legislation can be assumed to the extent that the design

¹¹ And where the measure is approved for no more than 10 years, as well as complying with the more general principles of State aid compatibility under Article 107(3), Point (C) of the Treaty on the Functioning of the European Union.

aligns with that of the relevant target model. However, CISAF compliance is not a hard constraint.

As such, the CRM 2.0 design approach is not to be bound strictly to CISAF's target model – the expectation is that the requirement of the model for an adequacy need to be identified in the ERAA may not be met, meaning that the State aid assessment will need to invoke CEEAG in any case – but to use the model as a guide in aligning the design with the European Commission's intent.

An initial review of compliance of the current CRM with the CISAF target model indicates that the existing CRM meets many of the requirements as it stands. Some areas of note where the current CRM may not be aligned with the target model are set out in Table 3.

Table 3: CISAF requirements with which the current CRM may not be aligned.

| Requirement | Comment |
|--|--|
| Requirement 1: that the ERAA demonstrates the adequacy need, and that the DRFs used are those output from the ERAA (once available). | The latest (2025) ERAA does not show an adequacy need for Ireland until 2035. The current DRF methodology is separate from the ERAA. |
| Requirement 7: [...] Individual capacity providers are allowed to deviate from the default de-rating factor for the technology at issue (up to at least 15% of the standard de-rating factor of that technology). | While INCTOL/DECTOL provisions exist, only DSUs have been allowed to deviate from their default derating factor to date. |
| Requirement 8: The capacity mechanism must be open to cross-border participation. | Not currently the case, but in progress. |
| Requirement 14: Beneficiaries must be identified through a competitive bidding process with bids ranked according only to their price per de-rated unit of available capacity per year, and support paid according to the clearing price. | The locational capacity constrained zones are an exception to this. |
| Requirement 18: The delivery window must be a single fixed period of up to one year between 1 November of year Y until 31 October of year Y+1. | Offset by 1 month from current CRM design. |
| Requirement 20: Beneficiaries must face non availability penalties whenever unavailable in a delivery period or test. [...] | This is only the case where the RO triggers. |
| Requirement 22: Regarding the coordination of the procurement of flexibility and capacity. | In line with the new provisions related to flexibility in the Electricity Market Reform. |

Requirement 26: At least 90% of the capacity mechanism costs must be allocated to consumers based on their consumption during at least 1% and at most 5% of the highest price hours each year.

The current cost recovery approach targets costs at the period 07:00–23:00, Mon–Fri. (approx. 48% of hours, not price related)

5.3 Conclusion

The design of the existing CRM is compliant in many respects with the EU legislative and State aid framework.

Some areas where we consider development is needed stem from the Clean Energy Package, while other areas require examination due to more recent developments in the framework over the last few years.

Explicit cross-border participation is a requirement of the Electricity Regulation that is not currently met. This is already being progressed however, and separately to the current review.

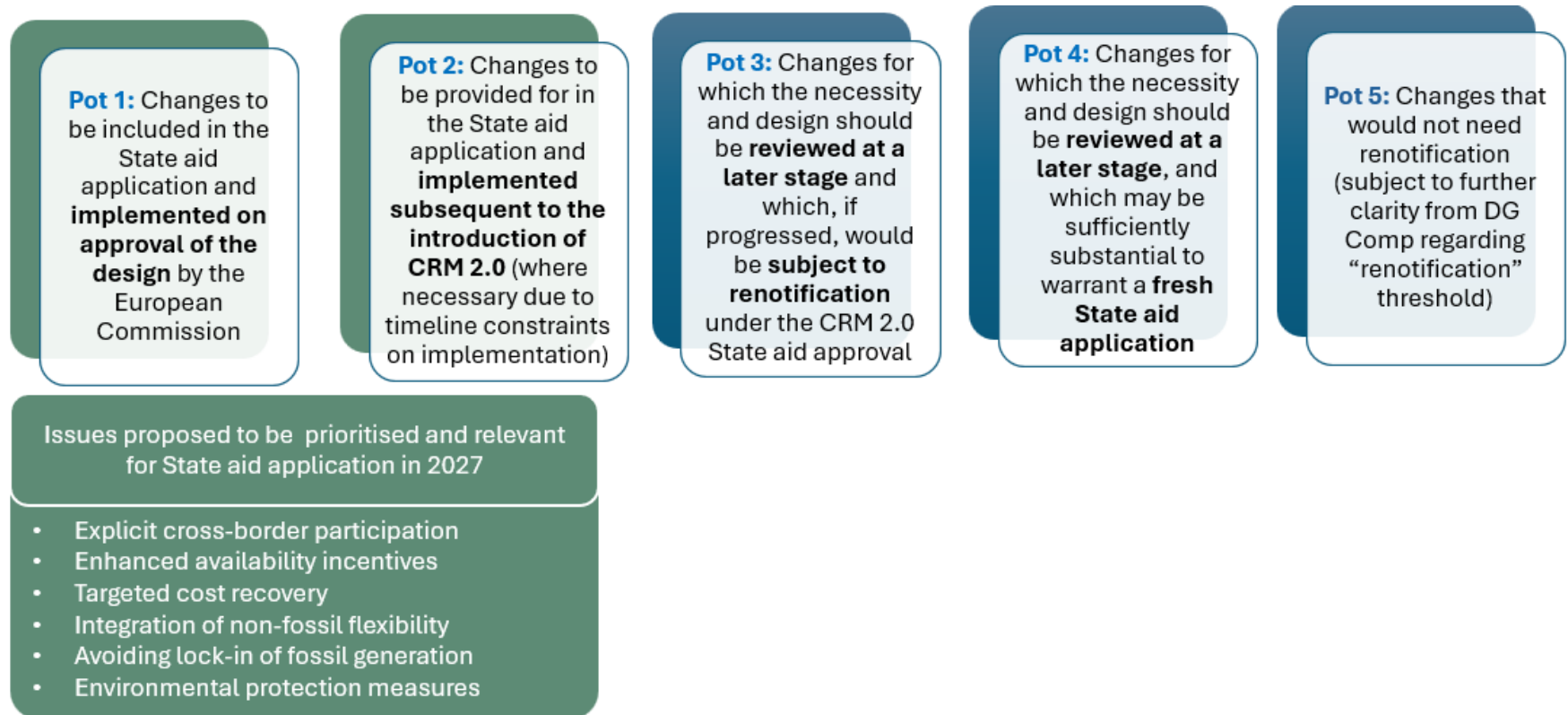
The requirement within the Electricity Regulation for there to be **incentives for capacity providers to be available** at times of expected system stress / appropriate penalties applied to capacity providers that are not available at times of system stress is in principle met by the RO in the SEM. However, we consider that in practice, the RO does not create a sufficient availability incentive, and that this is an area that warrants further examination in the development of CRM 2.0.

The requirement that the costs of the CRM be borne by the market participants who contribute to the need for the measure is met in part by targeting capacity cost recovery at the “daytime” hours. However, CISAF indicates the European Commission’s preference for more granular **temporal** targeting. In addition, we understand that DG Comp considers that while locational capacity constraints persist in the SEM CRM, they should be accompanied by **locational** cost recovery. Both elements points to more **targeted cost recovery** as being an aspect of the design to be developed in CRM 2.0.

More recent developments in the framework will require examination of the appropriate means of **integrating non-fossil flexibility** and capacity procurement. Decarbonisation measures designed to **avoid lock-in** of gas-fired generation and to promote **environmental protection** will also need to be considered.

Given that legislative compliance is a hard constraint, we classify these design elements into Pots 1 or 2 i.e. we recommend that these issues be prioritised and developed for the State aid application targeted to take place in H1 2027, Figure 5.

Figure 5: Classification of CRM development needs based on review of legislative and State aid requirements.



6 Review: Challenges with the current CRM

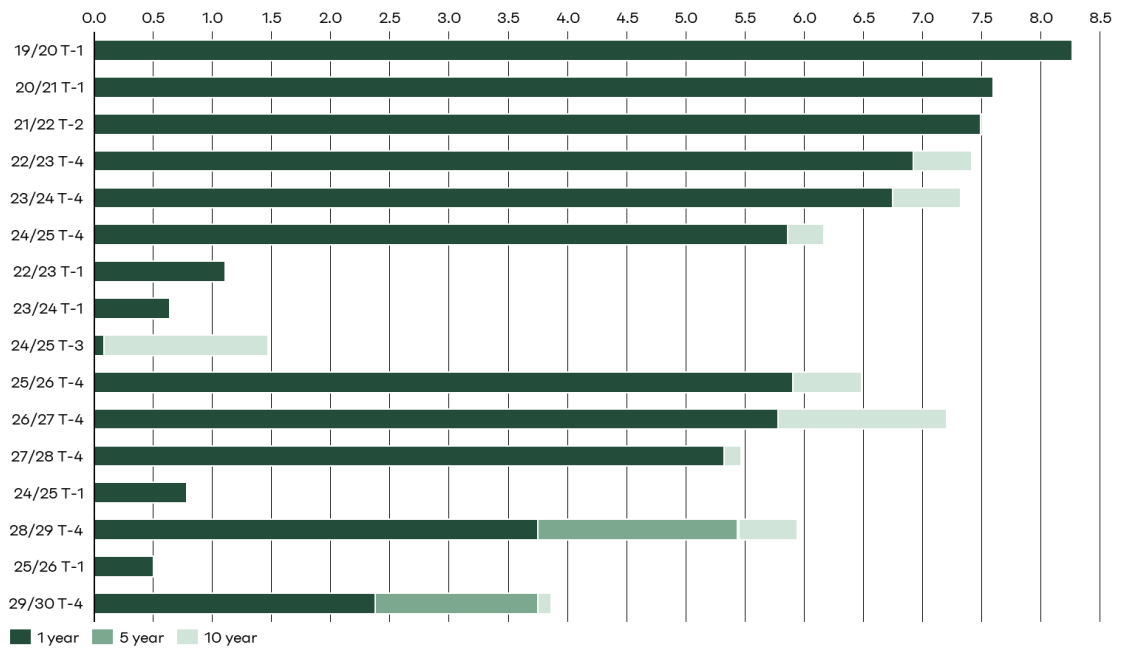
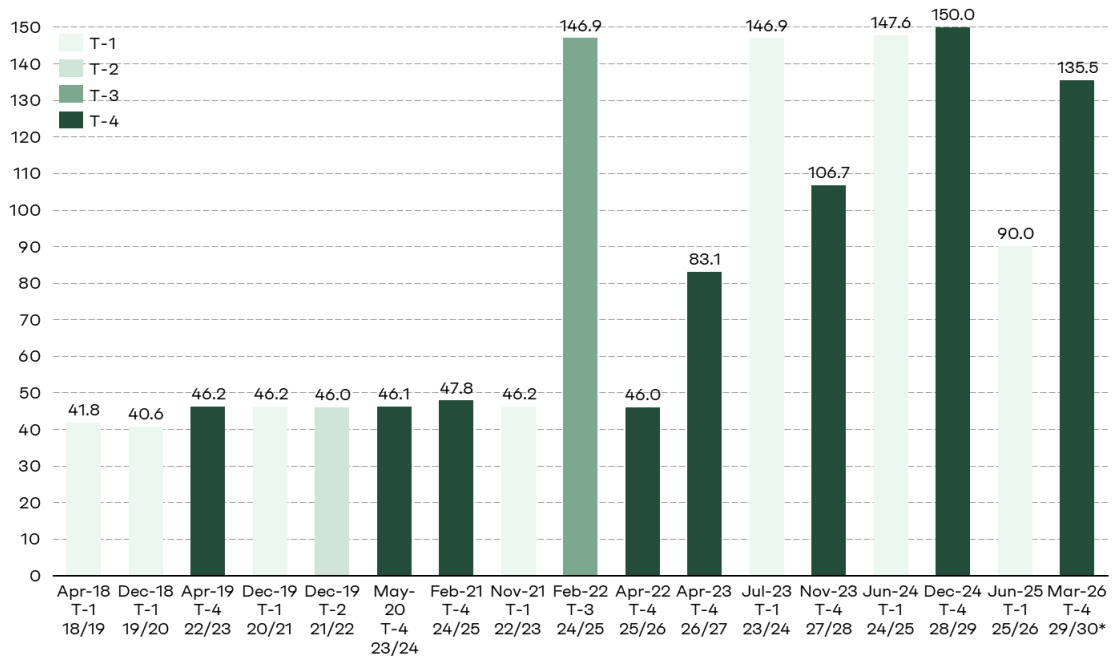
In this section, we consider what the challenges have been with the current CRM and what improvements are needed, based on an analysis of the modifications to the CRM to date, an assessment of the CRM review carried out in 2022, the material gathered from stakeholder workshops, and regular discussion with the RA CRM teams. We examine the CRM through the following lens:



The current CRM was designed over the period 2015-2017 and implemented as part of the revised SEM arrangements, which went live on 1 October 2018. The volumes of capacity procured in each auction to date are shown in Figure 6 below. The total volume of 10-year new capacity contracts awarded under the existing CRM is 5.4 GW. Of this, 2.1 GW has been granted an extension to their delivery timeframe by the SEM Committee, 1.5 GW has been terminated, and 1.5 GW has delivered to date, with the balance in the pipeline.

The clearing prices in each of the auctions are shown in Figure 7. The earlier auctions were cleared by existing capacity, with any new capacity procured as a result of the application of the locational capacity constraints and therefore paid as bid. In more recent auctions, the clearing price has increased, with auctions being cleared by existing capacity with a USPC or by new capacity at or close to the auction price cap.

The current CRM design includes a defined process for modifying the governing code, and these modifications provide useful insight into the development needs of the existing mechanism as perceived by the RAs, the TSOs and industry. In addition, a review of the performance of the CRM was carried out in 2022, which constitutes an informative perspective on the challenges with the current design. We have also gathered feedback from stakeholders at each of three workshops held with the RA teams, the TSOs and industry respectively.

Figure 6: Capacity procured under the CRM by contract length (GW, derated)

Figure 7: CRM Clearing prices to date (€/kW derated, nominal money)


**Provisional results*

6.1 Modifications implemented since I-SEM go-live

Since October 2018, over 70 modifications to the Capacity Market Code (CMC) have been introduced, Annex D. We have classified these into the categories listed in Table 4. The number of CMC modifications falling into each of these categories by year is shown in Figure 8.

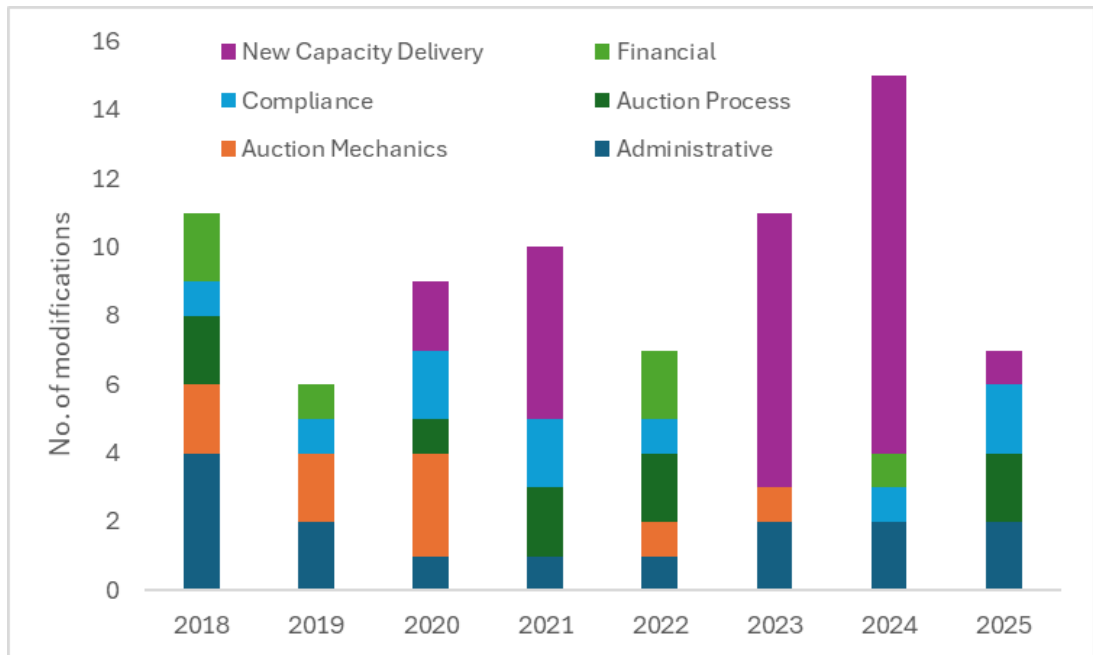
The clear trend is an increasing number of CMC modifications related to facilitating the delivery of new capacity, with this being the dominant category in 2021, 2023 and 2024. In 2023 and 2024, this category accounted for nearly three-quarters of all CMC modifications implemented.

This indicates that as CRM auctions have progressed, with new contracts awarded and a pipeline of new capacity building up, challenges related to the delivery of this new capacity have become the dominant drivers of change to the design.

Table 4: Categories of Capacity Market Code modifications

| Category | Category Definition |
|----------------------|--|
| Administrative | Administrative modifications include editorial and clerical changes, often aligning two parts of the code that were not in agreement and where clarification was required. |
| Auction Mechanics | Updates to the mechanics of the auction process. |
| Auction Process | Modifications to the process of the auction, including changing the information that must be published and auction timelines and dates to be adhered to. |
| Compliance | Modifications to align and comply with State aid guidelines, environmental requirements and transparency. |
| Delivery of Capacity | Modifications to reduce risks of non-delivery of capacity, both through incentives for early delivery, extension of longstop dates to reflect 3rd party delays and how steps to completion are assessed. |
| Finance | Modifications to remove negative impacts on the financing of new capacity, improvement of transparency and alignment with market standards. |

Figure 8: Modifications made to the CMC since 2018, classified by category (note that the data for 2025 is incomplete as some of the modifications from that year are still in progress).



6.2 EY Review

In 2022, in the context of the TSOs' forecast capacity shortfall in the most recent Generation Capacity Statement at that time¹², the RAs engaged EY to carry out a review of the CRM to establish whether the mechanism could be strengthened to "*deliver on its core objective of ensuring security of supply*"¹³.

EY's assessment produced a series of recommended potential remedies, structured around the following four questions:

1. Was sufficient capacity procured in capacity auctions?
2. Did capacity auctions attract sufficient participation?
3. Did new capacity procured in auctions get built?
4. Was the capacity procured of sufficient value?

The list of potential remedies, in order of their assessed impact, is shown in Table 5, along with AFRY's commentary on progress in each area since the time of the EY review. The full overview of the assessment outcome is replicated in Annex E.

¹² [208281-All-Island-Generation-Capacity-Statement-LR13A.pdf](#)

¹³ [SEM-22-054A Performance of the SEM CRM.pdf](#)

Table 5: Potential remedies for CRM

| Impact | Potential Remedies | Progress since EY review |
|--------|--|--|
| 5 | Greater transparency of target setting through a panel of technical experts (PTE) assessment of EirGrid recommendations, with findings published, and explanation of process by which GCS forecasts are translated to Target Volume to procure in capacity auctions. | PTE expected to be formed shortly Volumes information notes published post-auction |
| 5 | More explicit accounting of non-delivery in setting target, with two options for implementation: <ul style="list-style-type: none"> ▪ Introduce process to monitor progress reports for early indication of non-delivery; OR ▪ Apply a standardised adjustment to capacity requirement to account for likelihood of non-delivery, review inputs to adjustment % on a periodic basis. | Developer reporting introduced Non-delivery adjustments taken into account in setting auction volumes |
| 5 | Greater investment in infrastructure to enable more competitive all-island market and reducing pressure for new build to be situated in particular locations. | Through relevant price controls |
| 5 | Increase lead time to at least 4 years from announcement of auction results to start of capacity delivery year. | Consultation published ¹⁴ |
| 5 | <ul style="list-style-type: none"> ▪ Recalibrating the administrative scarcity pricing function so BM pricing better reflects market scarcity and causes a higher frequency of periods with prices above the RO strike price. ▪ Refining the principle of flagging interconnector actions from SEM BM prices to drive prices that are more likely to exceed the RO strike price and more reflective of the value of generation. ▪ Greater monitoring of technology performance in stress events to inform future de-rating factor setting. ▪ Applying administrative penalties for | Amendments to administered scarcity decided on in SEM-25-029 ¹⁵ , with implementation to come |

¹⁴ [sem-26-003-options-for-the-timings-of-upcoming-crm-auctions.pdf](#)
¹⁵ [SEM-25-029 ASP Decision Paper.pdf](#)

| | | |
|---|---|---|
| | non-delivery to plants in specific locations where an amber alert has been raised and a plant is unavailable. <ul style="list-style-type: none"> ▪ Implement additional physical checks on existing capacity providers in periods with no stress events. | |
| 4 | More permissive approach to requests for extensions from new build projects (where likelihood of delivery is high). | CMC mods introduced via SEM-23-001 ¹⁶ and SEM-23-101 ¹⁷ |
| 4 | <ul style="list-style-type: none"> ▪ Implement baseline methodology for assessing the contribution of DSUs in reducing energy demand. <ul style="list-style-type: none"> ▪ Pay DSUs for negative generation up to the RO strike price. ▪ Determine energy-only stack within balancing market and compensate generators if instructed not to run for system reasons. ▪ Set single derating factor for DSUs regardless of size. ▪ Implement provision for secondary trading for capacity providers. | Proposed decision on DSU energy payments published ¹⁸ Online secondary trading live as of April 2026 |
| 3 | Move to tighter reliability standard in line with other European markets. | Done |
| 3 | Requirement of new prospective capacity to have all necessary consents to pre-qualify for auction. This remedy is potentially redundant if remedy 3.1 is taken forward (i.e. extending auction lead times). | The latest CRU grid connection direction required planning permission; published intent to move away from directions from T-4 31/32 auction |
| 3 | Increase performance securities following the auction | Done |
| 3 | Require performance security to be lodged prior to auction. | |

¹⁶ [WP-05: Institutional Arrangements](#)

¹⁷ [SEM-23-101 Delay Mod Decision paper - for publication.pdf](#)

¹⁸ [Demand Side Units: A Revised Phase 1 Solution for Energy Payments and Other Issues, Proposed Decision Paper \(SEM-26-017\) | The Single Electricity Market Committee](#)

| | | |
|---|--|--|
| 3 | <ul style="list-style-type: none"> ▪ Allow 15-year contracts for the most capital-intensive new build (i.e. CCGTs, long duration storage). ▪ Making ancillary service contracts more accessible to new build by creating ancillary service contracts with a longer lead-time and duration in line with the CRM and by procuring the products in a single integrated auction process. | |
|---|--|--|

At a high level, in addition to the importance of network infrastructure build and of setting a tighter reliability standard, EY’s potential remedies relate to three key elements of the Capacity Market design and processes:

- Greater transparency and expert input to the **volume setting process**;
- Mitigating and accounting for **capacity delivery risk**; and
- Ensuring adequate incentives for capacity (including DSUs explicitly) to be **reliable once operational**.

For completeness, we have also assessed the content of the McCarthy Review to determine whether it is relevant for the purposes of this present review. However, the focus of the McCarthy Review is the broader Security of Supply Crisis in Ireland, which emerged in 2021, and not the design of the SEM CRM. The author defers consideration of the CRM design to the EY Review, which was also ongoing at that time:

“In view of the detailed analysis and consultation on the operation of the CRM which is underway [the EY Review], and the technical character of the issues involved in determining the appropriate features of the auction process, I consider that it is beyond the scope of my review to determine whether particular aspects of the market design gave rise to these difficulties.”

For this reason, we do not consider the content of the McCarthy Review further in this report.

6.3 RA view on CRM development needs

Alongside regular engagement with the RA CRM teams, a dedicated workshop was held with these teams in February 2026. The CRM development needs which were discussed covered a wide range of issues – from operational aspects of the mechanism to broader policy and longer-term strategic considerations. These are classified into specific areas of the CRM design in the sections that follow.

6.3.1 Compliance and penalty arrangements

Elements of the operation of the **Reliability Option** were raised – in particular, concerns regarding its effectiveness as an incentive for capacity units to be available when needed by the system, given the limited number of occurrences of “RO events”, during which the RO is triggered. The interaction of the RO with the energy price was also raised, with the observation made that prices in the ex-ante and balancing markets do not usually exceed the strike price of the RO when set based on participants’ bids, implying that the existence of the RO influences bidding behaviour. It was observed that changes shortly to be implemented to the operation of the Administered Scarcity Pricing mechanism¹⁹ may have the effect of increasing the frequency of RO events, though this may not on its own be sufficient to appropriately sharpen the incentive.

The broader penalty regime, was discussed, associated with “**deficiency**” in the form of:

- Operational non-availability when needed by the system (as related to the operation of the RO, discussed above);
- Non-delivery (or late delivery) of awarded new capacity;
- Non-compliance with expenditure thresholds linked to ILCs; and
- Non-compliance with the CO2 emissions threshold imposed by the Electricity Regulation.

The role of auditing and ex-post checking of spend and emissions was considered, along with the concept of a clawback mechanism where instances of non-compliance are identified. The appropriateness of the performance security requirements was discussed, alongside their role in mitigating non-delivery. We understand this topic of deficiency to be a particular concern for SEMC also.

6.3.2 Practical considerations

The approach to State aid approval for CRM 2.0 was discussed and the value of obtaining a “dynamic” approval, which will allow SEMC flexibility to adapt the market design over time, was recognised. The question was raised as to the “renotification threshold” above which modifications to the CRM rules should be notified to the European Commission. It was observed that

¹⁹ [SEM-25-029 ASP Decision Paper.pdf](#)

establishing a process for identifying these modifications would be beneficial. Similarly, the idea was discussed of establishing a process for screening out modifications that have previously been raised in another form and rejected.

Overall, there was the view that the CRM processes would benefit from streamlining and simplification. The time taken for IT system implementation of changes to the rules was identified as a recurring constraint on the development of the market design. The potential for further transparency in the setting of volumes for the auction capacity requirements was also noted, including in relation to the link between the outputs of the TSOs' AIRAA and those of the ISAC 2 adequacy calculator currently used to determine the basic capacity requirements for the purpose of the CRM.

6.3.3 Delivery of new capacity

A number of points were raised in relation to the delivery of new capacity. These included the delivery timeframe associated with the main (T-4) auction and whether this is the appropriate timeframe, given challenges with delivery to date. The value of post-auction monitoring of delivery of new capacity was also discussed, alongside the importance of providing up-to-date information to the wider market regarding extensions granted and terminations effected. The question was raised as to the appropriate remedial action to be taken in the case of delays.

6.3.4 Cost-efficiency

The affordability pressures on consumers across the SEM were discussed and questions raised regarding the cost of capacity in SEM compared with other markets. The approach to recovering the costs of capacity from consumers was also raised and considered in light of State aid requirements related to targeting cost recovery at those consumers driving the need for capacity.

The potential to reduce costs through multi-year forecasting and procurement was considered, alongside the possibility of segmenting procurement by creating separate pots for new and existing capacity, or for decarbonised or flexible capacity.

Finally, the question of indexation of capacity payments was raised and considered in terms of where the risk of inflation best sits.

6.3.5 Market abuse

Opportunities for gaming or instances of market power were raised. These included matters related to the locational capacity constrained areas and concerns about market power within them. The opportunity for gaming more generally was discussed in the form of termination of one contract in order to enter a subsequent auction expected to be more lucrative. It was observed that this is not prohibited under the current rules.

6.3.6 Derating factors

The need to review the DRF methodology was discussed. This included the question of whether DRFs should be unit-specific and the role of the INCTOL

and DECTOL parameters in that context. The question was also debated as to whether DRFs should be set on a multi-year basis.

The appropriateness of the existing methodology for energy-limited capacity in particular was considered. The question was raised as to whether the fundamental marginal approach to derating taken in the SEM CRM remains appropriate going forward.

On a related note, the impact of annual run hour limits on the CRM and on the TSOs' operational decision-making was highlighted.

6.3.7 State aid requirements

Several diverse topics associated with the requirements of State aid were noted. These comprised:

- The persistence of **locational constraints** in the CRM auctions and the question of locational cost recovery;
- The position with regard to **DSU energy payments**;
- The integration of **flexibility** into the CRM, including the role of **interconnection** and cross-border participation, and the interaction of the developing LDES scheme with the CRM;
- Measures to **decarbonise** the CRM;
- **Technology inclusivity** and the appropriateness of the CRM design for all technologies, including DSUs; and
- The question of whether a **strategic reserve** would be sufficient to meet the adequacy need in the SEM.

6.3.8 Strategic

A number of more strategic items were discussed, including:

- The role of the CRM in the SEM in the longer-term and how this will evolve as the nature of adequacy concerns changes and as the technology mix on the system is driven towards decarbonisation and non-fossil flexibility;
- The interaction of the CRM with other long-term service procurements that might be introduced in future (e.g. for Hydrogen generation or CCS) and the role of the CRM in supporting these other services; and
- The interaction with LEU connection policy in Ireland, given the substantial contribution of data centres to forecast demand growth.

6.4 TSO initial view on CRM development needs

An informal workshop was held with the TSOs on the 10 March 2026. The TSOs noted at the start of this meeting that their input should not be considered the formal position of EirGrid/SONI, but that the teams were participating on an informal working level basis.

The TSOs’ thoughts on the CRM development needs, as gathered at this workshop, were similarly wide-ranging to those of the RAs. General commentary included the observation that the current CRM design is already compliant with many or most of the underlying principles of Capacity Mechanism design that stem from the Clean Energy Package. The importance of maintaining focus on the consumer interest during the development of CRM 2.0 was also noted.

The specific topics raised ranged from practical operational ones to forward-looking policy and strategic considerations.

6.5 Industry view on CRM development needs

An industry workshop was held in Dundalk on 24 March 2026. There were 61 registered attendees, representing a range of industry interests, as shown in Table 6:

Table 6: Attendee statistics for Industry Workshop

| Participant Category | No. of Participants |
|--------------------------------|---------------------|
| Generators | 21 |
| System Operators | 15 |
| Consultant / Advisor | 8 |
| Developer / Investor / Finance | 5 |
| Trader / Market Participant | 8 |
| Regulator / Government | 2 |
| Industry Associations | 2 |

The title of the workshop was: “*CRM Development Programme – Stakeholder Workshop*”. Attendees were asked for their input during two working sessions – the first of these sought industry views on the development needs of the current CRM and the second focussed on forward looking development needs for the longer term. An overview of the feedback received during each session is provided below.

6.5.1 Industry view on the development needs of the current CRM

A number of general observations were made in respect of the current CRM and its development going forward. These included the fact that the CRM has fostered healthier new entry than its predecessor (the pre-2018 Capacity Payment Mechanism, which was a price-based instrument). It was also

emphasised that simplicity should be a design goal going forward and that the objectives of CRM 2.0 should not lose focus on (in particular) reliability, affordability for consumers, and investability. The more specific areas raised are described in the sections that follow.

1. Transparency and Access to Information

Some attendees considered that CRM-related information generally is currently too dispersed, with no single consolidated source, making it difficult for participants to obtain a holistic understanding of how the mechanism works. It was noted that the Capacity Market Code alone does not provide a full picture of how the mechanism operates in practice.

A number of other areas were identified as needing greater transparency, specifically:

- The setting of **capacity requirements** and **demand curves** for the auctions – how they are calculated and what assumptions underpin them;
- The granting of **extensions** and **terminations**. Some attendees considered that there was insufficient visibility provided in regards to the timelines for these in particular;
- The **DRF methodology**, how it works in detail and what the underlying assumptions are. The implication was that it was difficult for industry to predict how DRFs would evolve over time, given the limited visibility they have of the methodology; and
- The assumptions underlying the **Best New Entrant calculation** and the plan for updating the cost of new entry.

Finally, the CMC modifications process was viewed positively, as providing openness and engagement, with some caution expressed regarding the potential for unintended consequences of modifications, particularly as might impact newer technologies.

2. Deliverability and Auction Timelines

Current auction lead times are seen as misaligned with realistic project **delivery** timelines, particularly given the time taken to obtain planning and grid / gas connections. The point was made that participants are required to undertake significant pre-auction investment and development work 6–7 years in advance, creating substantial exposure and bankability risk.

Some concerns were also raised that there is insufficient time for the resolution of disputes related to the qualification process. Overall, there was a view on auction **timelines** that greater alignment is needed between the processes that developers must follow related to planning and network connections, the lead time of the CRM auction, and the timelines of the auction processes themselves (e.g. qualification, reaching delivery milestones).

3. Derating Factors (DRFs)

DRFs were one of the most consistently raised issues at this workshop. Multiple aspects of the current methodology were highlighted as requiring change:

- The use of **historical data** for setting DRFs was seen as not being reflective of future system needs. Relatedly, current DRFs were considered by some attendees to not adequately reflect the characteristics of newer technologies in particular, for which there is no reliable historical data;
- Some attendees considered that **unit-specific** DRFs should be introduced;
- There can be a **jurisdictional** difference in unit reliability that should be reflected in the setting of DRFs; and
- The point was made that DRFs for both gas turbines and batteries in the SEM are **outliers** compared to other markets.

As described above, attendees considered that greater transparency and detail should be provided in relation to the calculation of DRFs. Some contended that materially different DRFs have been set for similar units without sufficient explanation.

4. Secondary Trading

Attendees raised the question of secondary trading and observed that it is not yet fully implemented, despite having been envisaged in the original market design. Enhanced secondary trading was viewed as critical to improving deliverability, reducing risk and supporting technically complex projects.

5. Bankability and Risk Exposure

Some attendees raised concerns regarding project bankability, which they associated with multiple factors:

- Inadequate revenues from the CRM (presumably associated with the price caps, as described in the section that follows);
- Risk exposure during long project development periods, combined with uncertainty as to the granting of extensions;
- Lack of clarity regarding delivery incentives and penalties once operational;
- The lack of indexation of capacity payments, especially for multi-year contracts, to reflect inflation and supply chain cost increases; and
- Contract length, with an extended contract length of up to 15 years proposed as a measure to support bankability.

6. Price Caps

The point was made that the multiplier applied to the Auction Price Cap has been increased over time, which was viewed as indicative of issues with the

underlying BNE calculation. The BNE methodology was described by some as outdated at this point and not being reflective of recent cost escalation. Reviews of the price caps were considered necessary going forward.

Some attendees also considered that the viability of advanced and emerging technologies is undermined by the fact that these technologies are subject to the same price caps as existing technologies.

7. Technology Neutrality

Attendees were of the view that the current CRM is designed primarily for the characteristics of **conventional generation**, with limitations therefore for other technologies, such as DSUs, Long-Duration Energy Storage (LDES) and other technically complex or emerging technologies. The qualification rigour is seen by some as being **unequal across technologies**, disadvantaging certain participants, and DSUs in particular. The point was also raised that capacity awarded Intermediate Length Contracts (ILCs) can “crowd out” technically challenging projects.

Overall, attendees asked for greater flexibility in order to properly accommodate non-conventional capacity in the CRM design, with the idea of facilitated entry routes for difficult-to-deliver, but system-beneficial technologies, also proposed.

8. Demand Growth

Linked to comments regarding transparency, attendees highlighted significant uncertainty around the future demand growth that is expected to be driven primarily by data centres. The question was raised as to whether the CRM has provided sufficient supply-side investment signals in response to this forecast demand growth.

Some attendees expressed doubts as to whether current demand-side participation meaningfully mitigates long-term adequacy risk.

Finally, the question was raised as to how the forecast change in demand *profile* would be accounted for in forecasting.

6.5.2 Industry view on longer term CRM development needs

General observations from attendees looking towards the longer term included recognition that the capacity supply curve will materially change as RES penetration increases from ~40% to ~80%, as well as the idea that providing flexibility to participants rather than being overly rigid would help to reflect the practical and commercial realities of delivering projects across the SEM. The view was also expressed that early delivery incentives and greater notice periods in respect of the timing of capacity auctions could materially support investment. One group proposed that greater tolerance for project failure, where justified, would allow space for more innovative projects.

The further specific areas raised are described in the sections that follow.

1. System Evolution and Long-Term Planning

- Attendees highlighted the need for longer-term forecasting of system adequacy and reliability needs, in terms of both capacity and system services;
- Some attendees expressed concern about designing the future CRM without guaranteed availability of potentially highly influential technologies, such as carbon capture;
- The importance of representing SEM-specific characteristics at European level in the future development of relevant EU frameworks was also raised.

2. Constraints

It was noted that various constraints are expected to persist, or develop, and should be reflected in the design of CRM 2.0. These will include locational constraints, as currently, but may also be related to fuel supply (e.g. HVO) for example.

3. Decarbonisation

There was a desire for clearer carbon signals within the CRM, including through the facilitation of DSUs and of transition pathways for gas plants to renewables.

The importance of verifying carbon neutrality claims was raised, as well as questions regarding the definition of “non-fossil” technologies and whether the CRM is in fact an appropriate mechanism to incentivise decarbonisation.

Finally, there were calls to better accommodate repowering of existing sites, hydrogen readiness and both residential and aggregated demand response.

4. Questions on the Evolution of the Market Design

Some fundamental questions were posed by attendees regarding the evolution of the CRM design as the system transitions to net zero:

- Should the CRM remain technology-neutral?
- Should capacity costs be recovered on a MW or MWh basis?
- How will the CRM, system services, and future flexibility markets interact? Will revenue stacking be permitted?

6.6 Conclusion

Common themes emerge across the different sources used to inform this review. From the analysis of CMC modifications, the EY review and each of the three workshops, it is clear that delivery has been a key challenge for the current CRM and that the **delivery timeframe** should be reviewed.

The EY review and each of the workshops with the RAs and the TSOs highlight reliability of capacity once operational and/or the operation of the RO as a key challenge also. This relates to **availability incentives** for capacity market units.

The **derating methodology** is a theme that was raised strongly in each of the three workshops and that has become evident recently in the modifications process.

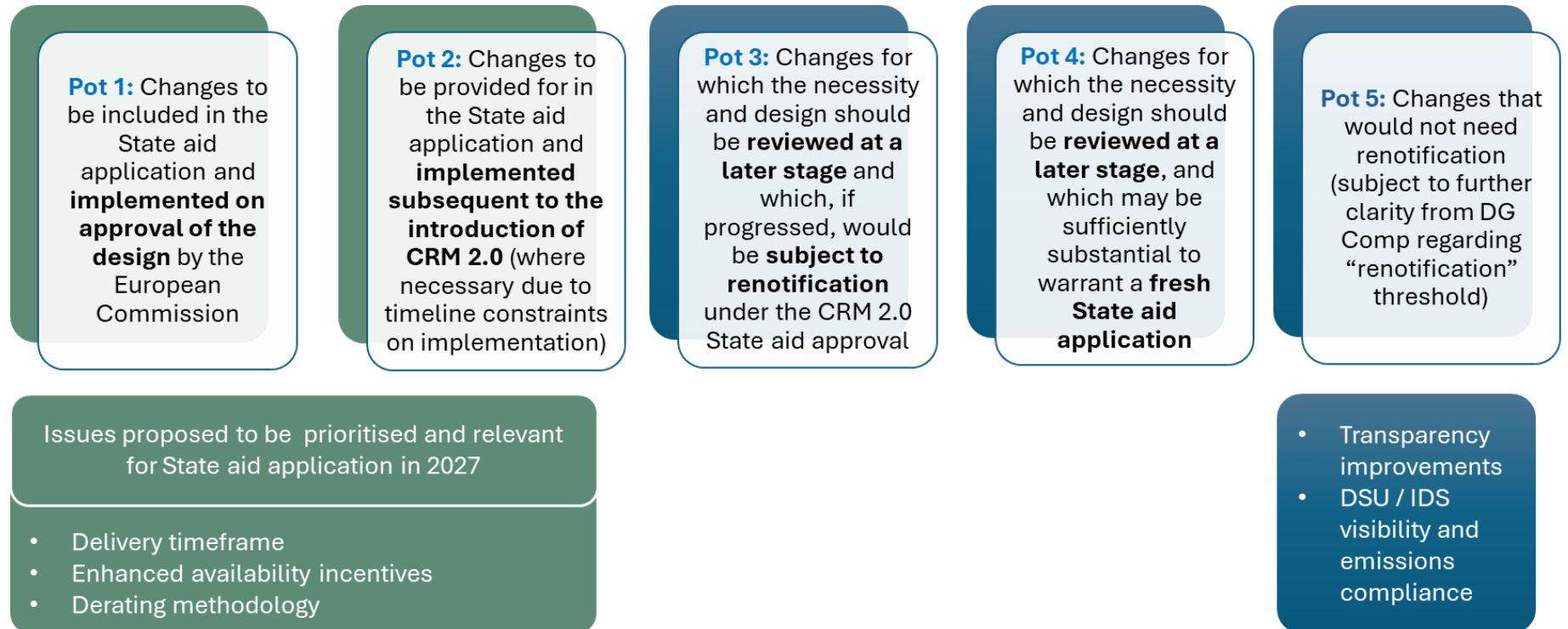
A range of issues related to **DSUs** as they interact with the design of the current CRM have been raised across the different sources, including the suitability of auction processes and timelines for the demand side, the incentives on DSUs to be available, and visibility of the composition of DSUs and the extent to which the IDss comply with emissions limits.

Finally, **transparency**, particularly as it relates to the volume setting process and to the publication of information on extensions and terminations is also a prominent theme.

We have classified these design elements into Pots 1-5 in Figure 9. The elements placed in Pots 1-2 are those that are considered most impactful, and that will need to feature in the State aid approval. The changes we have placed in Pot 5 are those that we consider will not need to feature in the State aid process, but that can be progressed by the RAs independent of the constraints of the State aid timeline.

The issues related to DSUs are diffuse and as such are captured via multiple elements – the suitability of the delivery timeframe for DSUs will form part of the consideration of the delivery timeframe more generally, while the review of the derating methodology will include the DRFs applied to DSUs. Visibility of DSU IDS composition and compliance with emissions limits sits in Pot 5.

Figure 9: Classification of CRM development needs based on assessment of challenges with the current CRM.

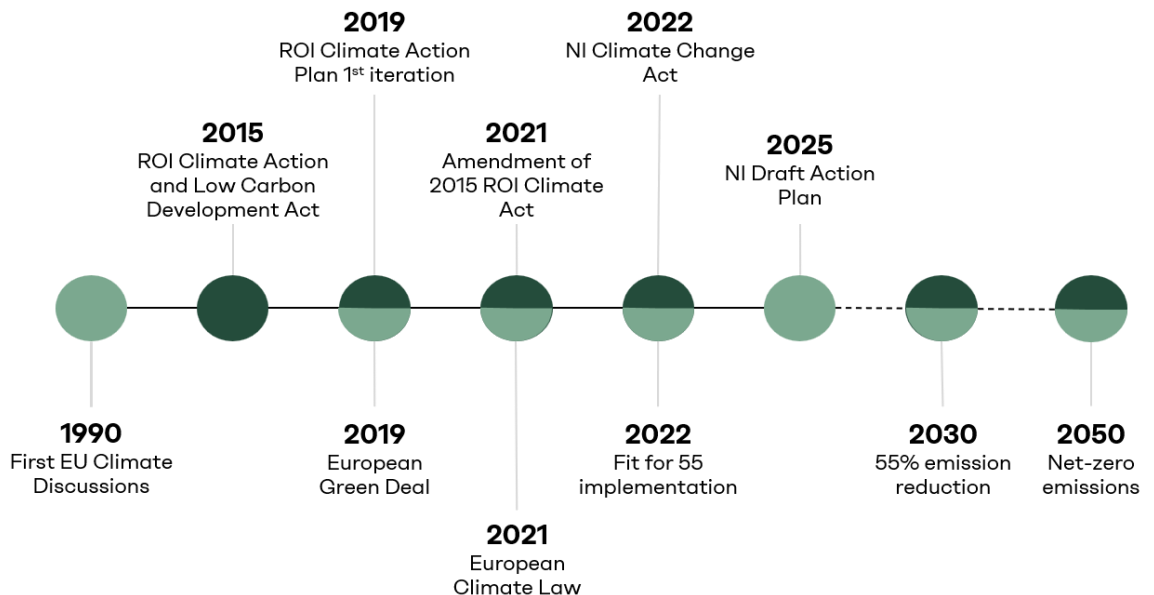


7 Review: Future Capacity Mix

In order to understand the future that CRM 2.0 will be expected to operate in, and help to deliver, this section contains an overview of the electricity policy landscape in Ireland and Northern Ireland and an outline of the expected evolution of the capacity mix in the SEM based on the TSOs' published adequacy assessment for the period 2026-2035 and longer-term scenario forecasting out to 2050.

7.1 Policy Landscape

EU and Irish/Northern Irish climate policy has evolved and continues to track a shared path to climate neutrality by 2050. The transition to net zero dominates the policy context across the SEM.



7.1.1 Ireland

In Ireland, the government is addressing the climate challenge through a range of policy, strategies, and actions. Their current commitment is reflected in:

- The annually updated Climate Action Plan (CAP), which sets out the specific targets and actions by sector to achieve climate commitments; and
- Carbon budgets, which are legally binding for each of the periods 2021-2025 and 2026-2030.

The Climate Action and Low Carbon Development (Amendment) Act 2021 set Ireland on a legally binding path to achieve climate neutrality by 2050. It introduced five-year carbon budgets and sectoral emissions ceilings. The Act holds Ministers accountable for progress in their sectors and requires local

authorities to develop Climate Action Plans every five years. Public bodies must align with climate goals, and planning laws now integrate climate considerations. Overall, the Act embeds climate governance into Ireland's legal system, supporting national and EU climate targets.

The CAP is the Irish roadmap to reduce GHG emissions by 51% by 2030 and thereby to be on a path to net zero by 2050. The renewables penetration target of up to 80% by 2030 is in part backed by the government by means of their Renewable Electricity Support Scheme (RESS).

Alongside the development of renewable electricity, security of electricity supply has featured prominently in national policy so far this decade, including the implementation of a Security of Supply programme of actions, which included the installation of up to 650 MW of Temporary Emergency Generation (TEG) at various sites across the country.

7.1.2 Northern Ireland

In Northern Ireland, energy strategy is also dominated by the objective of achieving net zero. The Northern Irish energy strategy – the Path to Net Zero Energy – was published in 2021 and set a target of 70% of electricity consumption from renewables by 2030. The Climate Change Act (Northern Ireland) 2022 increased this ambition to a target of at least 80% electricity consumption from renewable sources by 2030 and established a legally binding net zero target for 2050.

The Act also provided for the setting of carbon budgets, defining the maximum total emissions allowed over five-year periods. These are to be accompanied by five-year climate action plans setting out the policies that Northern Ireland departments will implement to meet the corresponding budget as well as to achieve the emissions reduction targets.

Furthermore, the Act required the establishment of an independent office known as the "Northern Ireland Climate Commissioner", the function of which is to oversee and report on the operations of the Act.

7.2 TSOs' Adequacy Assessment

The SEM TSOs carry out an adequacy assessment each year for the next ten-year period. In their assessment for the 2025-2034 period, the TSOs began the implementation of the new resource adequacy assessment methodology, developed by ENTSO-E pursuant to the Electricity Regulation. Their latest assessment – the AIRAA 2026-2035²⁰ – is the basis for the outline set out in this section.

The AIRAA 2026-2035 illustrates how the TSOs forecast the electricity system will evolve over the next ten years, reflecting current commitments, including awarded capacity contracts, demand connection offers, and national policy targets, as well as forecasts of economic growth etc.

²⁰ [All-Island Resource Adequacy Assessment](#)

The development of the system is characterised in terms of demand, generation and the overall adequacy position.

7.2.1 Demand

Demand across the island of Ireland is expected to grow substantially over the next ten years, driven by electrification of heat and transport and the connection of data centres and new technology loads.

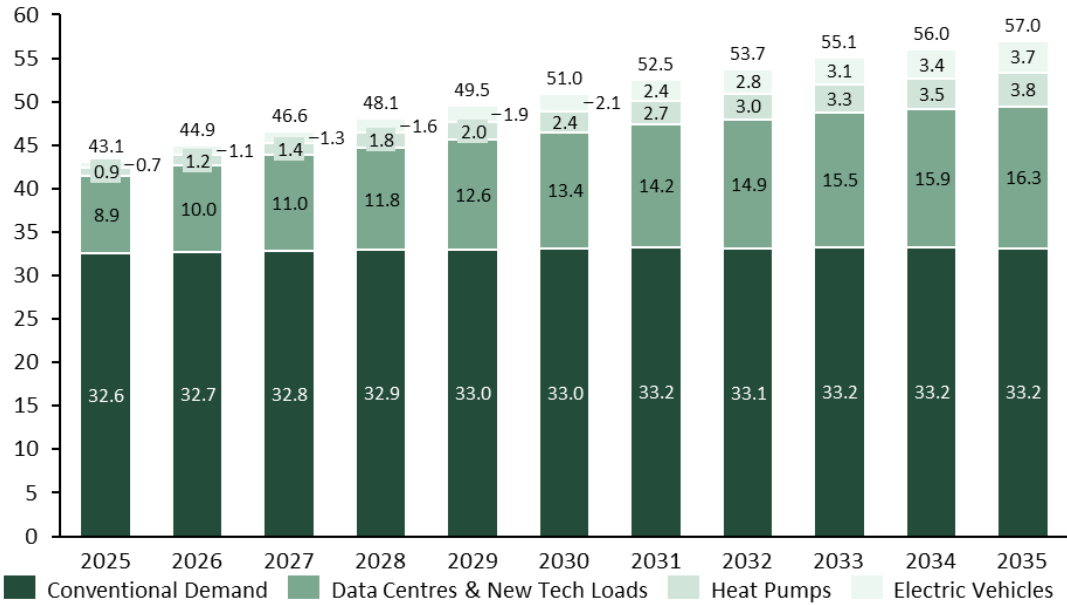
In Ireland, the principal driver of demand growth is data centres and new technology loads, with electrification becoming a more significant factor later in the decade. In the TSOs' median scenario, electricity demand in Ireland is forecast to increase 40% by 2035 from 2024 levels, with data centres and new technology loads forecast to account for 32% of all electricity demand by 2030.

In Northern Ireland, electrification is the main driver of demand growth, with a smaller contribution forecast from data centres and new technology loads. In the TSOs' median scenario, electricity demand in Northern Ireland is forecast to increase 31% by 2035 from 2024 levels.

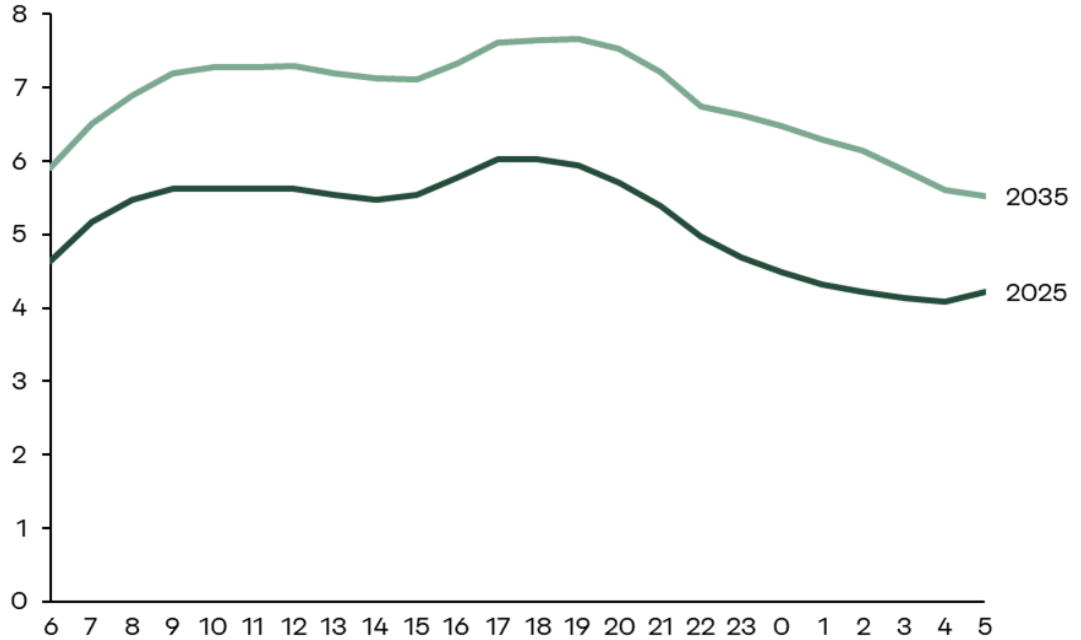
Figure 10 shows the forecast growth in all-island demand out to 2035, based on the TSOs' median scenarios and broken down by demand type.

Peak demand is also expected to increase, with EirGrid forecasting an increase of 21% in peak demand in Ireland by 2035 from 2024 levels and SONI forecasting an increase of 25% by 2035 from 2024 levels.

As demand increasingly becomes associated with new types of consumption i.e. data centres, heat pumps, electric vehicles, the typical demand profile across the system begins to change, Figure 11. This is because, unlike the residential profile which features peaks in the morning and evening time, data centres for example have a flat demand profile across the day, and smart charging of electric vehicles introduces a peak during the nighttime hours when conventional demand is usually low.

Figure 10: All-Island yearly demand breakdown by usage (TWh)


Source: AIRAA 2026-2035

Figure 11: All-Island hourly demand for 2025 & 2035 (GW)


Source: ENTSO-E Demand Forecasting Tool, AIRAA 2026-2035

7.2.2 Generation

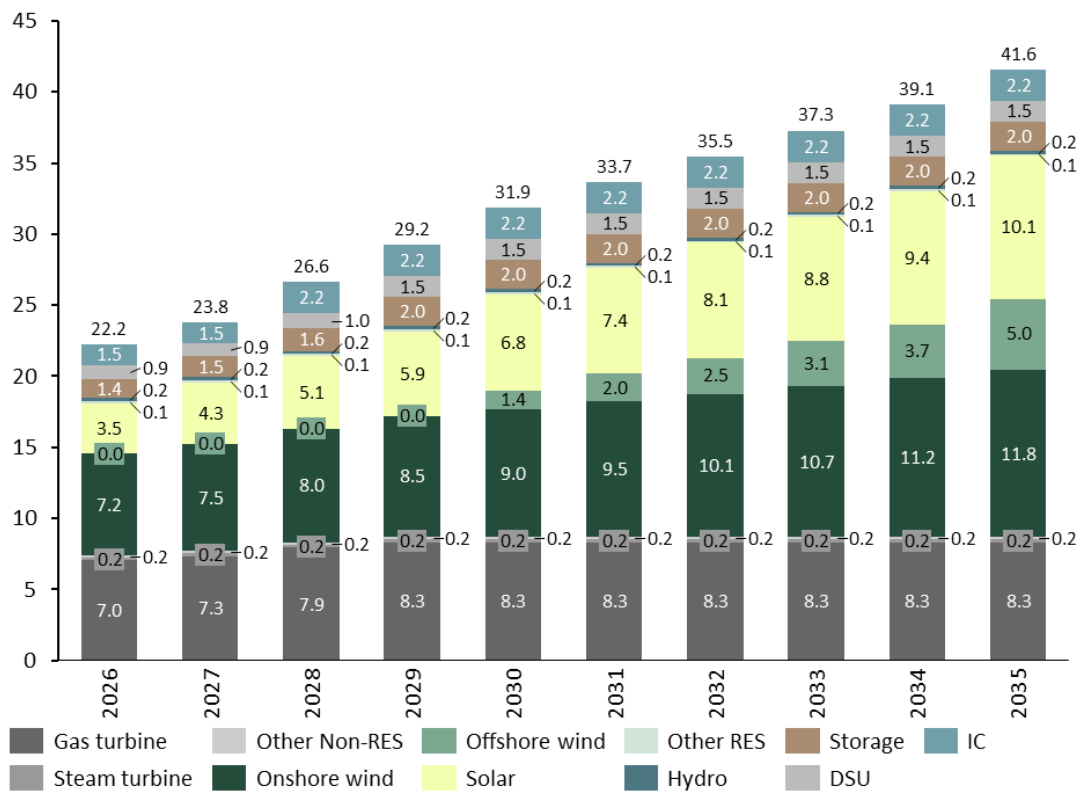
To meet increasing demand, and advance the decarbonisation objective, installed generation capacity is forecast to increase by close to 50% out to 2035.

As seen in Figure 12, renewable capacity, and most notably solar and offshore wind, is forecast to continue to increase across the island, by about 18% out to 2035 (at a rate of 1.9% per annum).

However, the system is expected to continue to need existing and new thermal (gas) capacity for the next decade (and beyond) despite the decarbonisation trajectory defined through policy in both jurisdictions.

Storage (mainly BESS) capacity also grows sharply, by 43% over the ten-year period (at a rate of 4% per annum). In addition to its position as a provider of flexibility and system services, storage will also have a role to play in system adequacy.

Figure 12: All-Island Capacity (GW)



Source: AIRAA 2026-2035

7.2.3 Adequacy

AIRAA

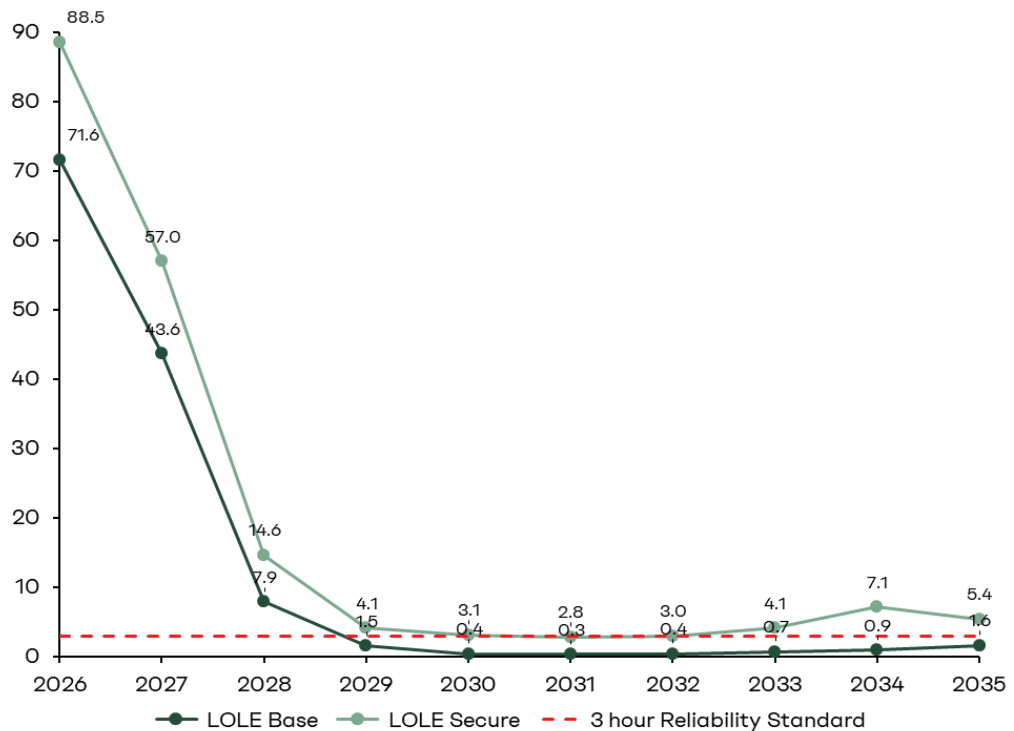
EirGrid’s assessment of the adequacy position in Ireland shows the Reliability Standard being exceeded in the short term in both their Base and Secure scenarios. In their Secure scenario, the Loss of Load Expectation also exceeds the standard by a small amount in most years within the study horizon out to 2035, Figure 13.

This adequacy position translates into a capacity deficit for Ireland in the secure scenario of 1,420MW in 2026, which falls to a minimum of 0MW in 2031, before increasing again to 420MW in 2035.

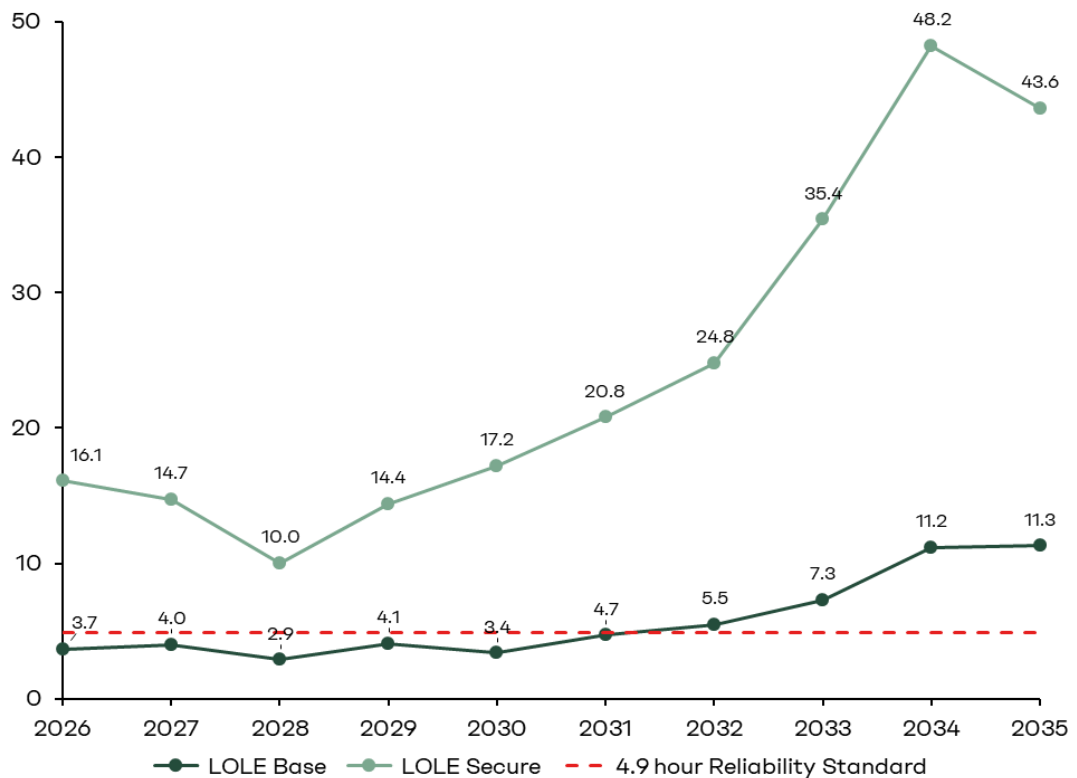
SONI’s assessment of the adequacy position in Northern Ireland shows the Reliability Standard being exceeded in the longer term (from 2032-2035) in the Base scenario. In their Secure scenario, the standard is exceeded from 2026 onwards, Figure 14.

This adequacy position translates into a capacity deficit for Northern Ireland in the secure scenario of 210MW in 2026, which falls to a minimum of 80MW in 2028, before increasing again to 320MW in 2035.

Figure 13: Base and Secure Loss of Load Expectation Results for Ireland



Source: AIRAA 2026-2035

Figure 14: Base and Secure Loss of Load Expectation Results for Northern Ireland


Source: AIRAA 2026-2035

ERAA

The 2025 European Resource Adequacy Assessment (ERAA)²¹ does not identify an adequacy issue in Ireland or Northern Ireland in 2028 or 2030. In 2033, the ERAA finds that the Loss of Load Expectation in Ireland increases, but remains “within range of risk”, while that in Northern Ireland is within standard. In 2035, The reliability standard in Ireland is exceeded, while the LoLE in Northern Ireland increases to “within range of risk”.

In summary therefore, as seen in Table 7, the latest version of the ERAA finds that there is no adequacy need across the island in the short term, while an issue begins to emerge in 2033-2035.

²¹ <https://www.entsoe.eu/eraa/2025/>

Table 7: Results of 2025 ERAA for Ireland and Northern Ireland, LOLE (h/year).

| Study year | Ireland | Northern Ireland |
|------------|---------|------------------|
| 2028 | 2 | <1 |
| 2030 | 2-3 | 1-2 |
| 2033 | 3-5 | 1-2 |
| 2035 | 4-6 | 3-5 |

7.2.4 Missing money

AIRAA 2026-2035 introduced a partial Economic Viability Assessment (EVA) as a new element, in compliance with the requirements of the Electricity Regulation. This assessment examined the forecast amount of capacity that would be commissioned or decommissioned in the absence of a Capacity Mechanism, under a range of assumptions. It did not go so far as to determine the impact of the EVA outcomes on the adequacy position. The full EVA is to be included in next year's iteration of the AIRAA and will include the assessment of the adequacy impact.

The EVA assesses whether generation units can recover their operating costs in an energy-only electricity market. If generators are unable to cover their operating costs, they may exit the market, potentially leading to adequacy concerns. This means that the EVA can inform consideration of the future need for additional measures such as the CRM. The 2026 assessment focused on establishing and testing the EVA process across five different scenarios reflecting assumptions on scarcity rent, revenue stacking and technology costs. The following sections detail the scenario assumptions, the results and the conclusions from the EVA.

Scenarios

The EVA scenarios explore generator viability under differing assumptions on scarcity pricing, revenue stacking and technology costs. Together they test whether an energy-only market can sustain existing capacity across realistic and conservative market conditions. The results highlight the sensitivity of resource adequacy to pricing design, the availability of ancillary services revenues and technology cost uncertainty.

Five counterfactual scenarios were considered under the EVA to demonstrate the impact of different revenue and cost input assumptions:

- 1. With scarcity pricing:** In this scenario, the price cap in the economic dispatch was fixed to the values used in ERAA 2024. The intention was to assess economic viability under a price cap assumption aligned with ERAA 2024.
- 2. Without scarcity pricing:** In this scenario, electricity prices in the economic dispatch were capped at €500/MWh. The rationale for this assumption was based on consultation feedback highlighting that SEM prices have rarely exceeded €500/MWh.
- 3. Energy-only revenue:** Under this scenario, generators earned only energy market revenues and not ancillary services revenues. This

scenario was included based on consultation feedback that stressed the uncertainty associated with revenues from ancillary services.

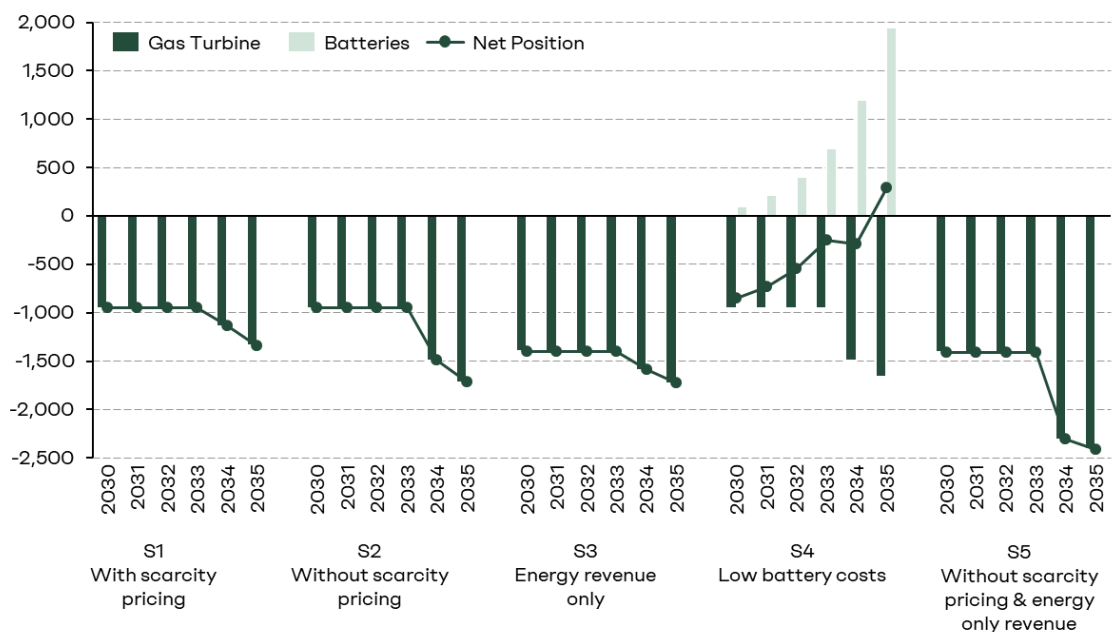
4. **Low battery costs:** This scenario was designed to assess the impact of lower storage costs and to test whether the EVA framework can add additional new technologies when costs are sufficiently low. Battery capital and operating costs were assumed to be 30% lower than in the base scenario, and the assumed economic lifetime of batteries was increased from 10 to 20 years.
5. **Without scarcity pricing and energy-only revenue:** This scenario combined elements of consultation feedback received, particularly those reflected in Scenarios 2 and 3. Energy prices were capped at €500/MWh, no system services revenues were included, and the highest-revenue Monte Carlo sample from each weather scenario was excluded.

Results

The key results from this first iteration of the EVA, are shown in Figure 15.

1. Across all scenarios there was a substantial amount of capacity which was determined to be unviable. The order in which units went offline was based on their position in the merit order curve, with those running least in the energy market being the first to show a negative Net Present Value and be taken offline.
2. There were limited new units brought online in any of the scenarios modelled. Only in Scenario 4 (low battery costs) was new battery capacity forecast to come online, while no gas units were brought online in any scenario.

Figure 15: EVA 2026-2035 results, showing rated MW capacity changes by year across the five scenarios modelled.



Source: EirGrid & SONI

Conclusions

Although the 2026-2035 EVA represented only a partial implementation of the full methodology, it clearly indicates that without a capacity mechanism, a significant amount of gas capacity would decommission, while no new capacity would come online except where favourable cost assumptions make new battery capacity viable. The next iteration of the EVA is expected to provide greater insight into the types of plants that are unviable in the absence of a Capacity Mechanism, as well as the resulting impact on the adequacy position.

7.3 TSOs' Scenario Planning

The latest published scenario planning exercise from the SEM TSOs is Tomorrow's Energy Scenarios (TES) 2023²². The publication is intended to "Support Government and Regulatory Authorities in the development of energy policy and market design development required to decarbonise the power system."

TES 2023 considers four distinct energy scenarios for enabling the transition to a decarbonised power system over the period 2030-2050. Each scenario places a different emphasis on key elements of the electricity system, such as interconnection and offshore, as well as the development of new technologies. The study outlines possible future pathways for the electricity system out to 2050 and reflects energy policy positions to consider how electricity demand may change over this period, and how electricity supply will need to respond while meeting decarbonisation objectives.

The four TES 2023 scenarios are as follows:

Self-Sustaining: this "follows a fast-paced transition away from fossil fuels to electrification in all sectors. This scenario is focused on meeting Ireland's and Northern Ireland's domestic electricity needs, increasingly through renewable generation supported by other technologies such as battery storage and carbon capture and storage. Self-Sustaining shows a net zero power system from 2040."

Offshore Opportunity: this "also follows a fast-paced transition to a decarbonised power system. This scenario sees a faster and larger development of offshore wind and results in the power system becoming a significant net electricity exporter through interconnection. Offshore Opportunity also shows a net zero power system from 2040".

Gas Evolution: this "follows a steadier pace of energy transition with electrification supported by increasing demand for green hydrogen in some sectors. The scenario includes significant renewable generation capacity to produce both electricity and power electrolysis plant to produce green hydrogen. Gas Evolution shows a net zero power system from 2045".

Constrained Growth: this "is the slowest of the four scenarios to decarbonise. This speed in development relates to both the rate of electrification of demand and the development of decarbonised generation capacity. With slower development of renewable generating capacity, it shows greater reliance on electricity imports when domestic supplies are not sufficient to meet demand. Constrained Growth shows a net zero power system from 2050."

The technologies considered in the TES 2023 are as follows:

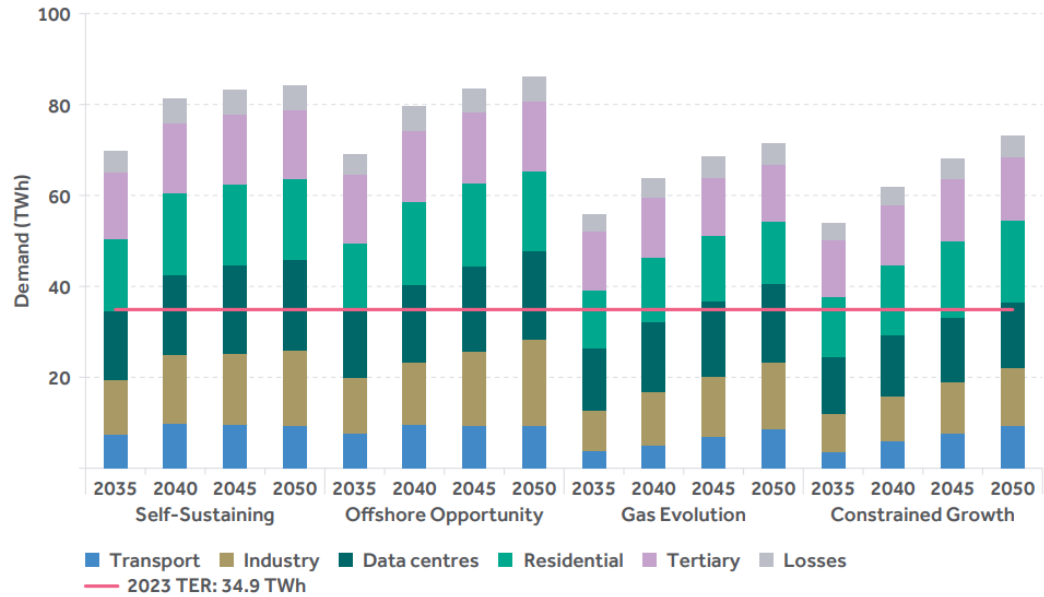
- Renewables such as solar, onshore and offshore wind.

²² <https://cms.eirgrid.ie/sites/default/files/publications/TES-2023-Final-Full-Report.pdf>

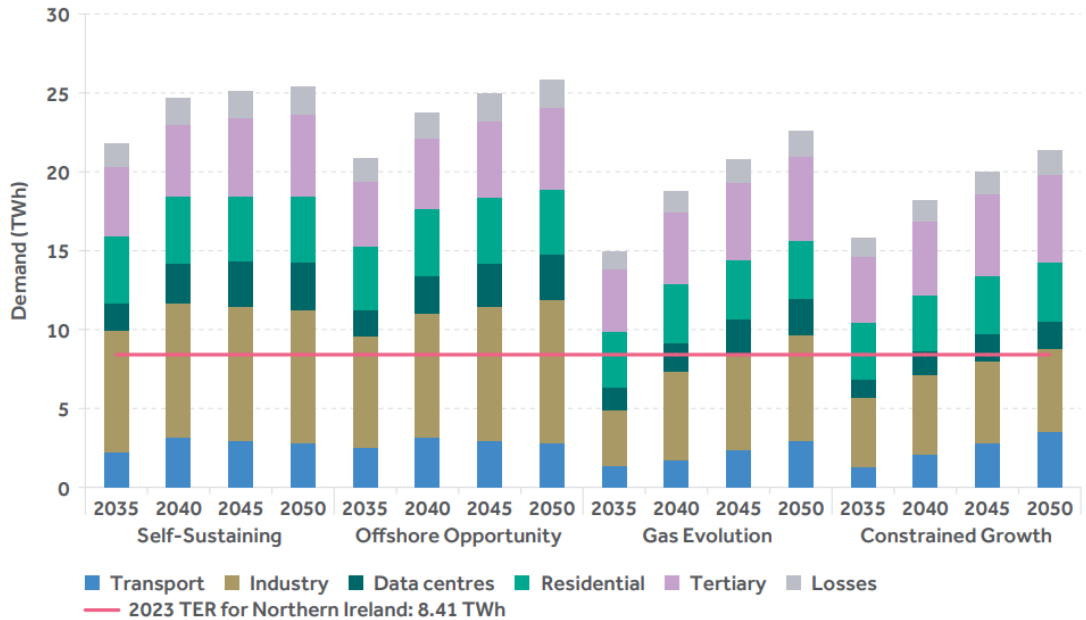
- Energy storage through pumped hydro, short-medium duration batteries and long-duration energy storage (LDES).
- Flexible thermal generation technology such as natural gas, hydrogen and biomass.
- Carbon capture and storage.
- Electricity interconnection between Ireland and Northern Ireland with Great Britain and continental Europe.

7.3.1 Demand

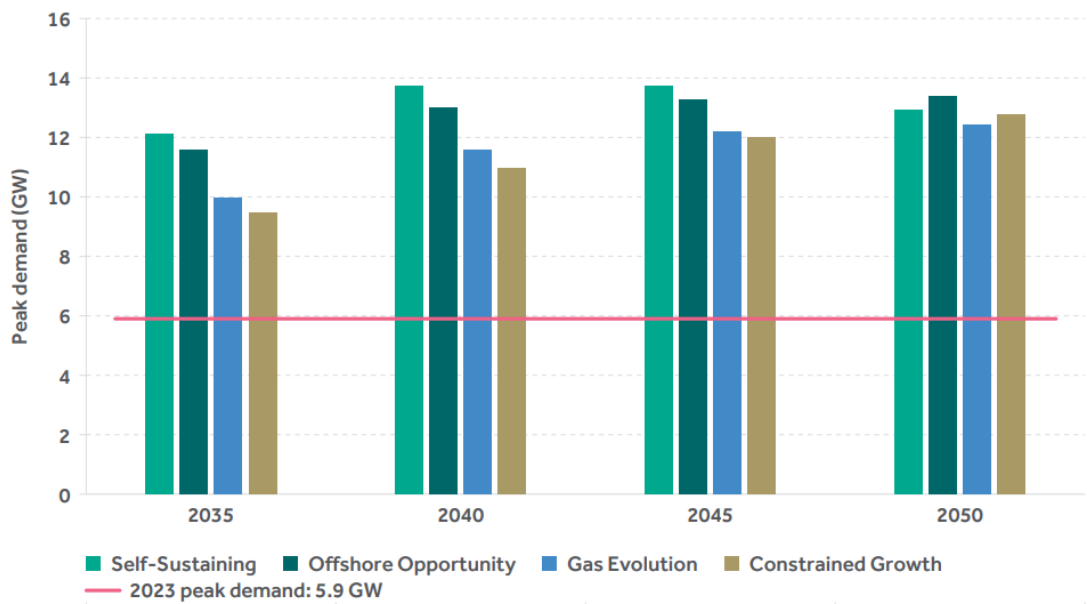
TES 2023 analysis shows electricity demand more than doubling by 2050, from 2023 levels, due to population growth and increasing electrification in all sectors, Figures 16 and 17. Despite an expected increase in energy efficiency, meeting the increased demand is expected to require significant development of the power system. This will include a key role for **demand flexibility**, with demand needing to be sufficiently flexible to adapt to fluctuations in variable renewable generation. Improvements in energy efficiency and demand flexibility will be key to helping manage peak loads on the system. The expected evolution of peak demand in Ireland and Northern Ireland is shown in Figures 18 and 19, which illustrate the substantial growth in peak demand that is expected in both jurisdictions.

Figure 16: Evolution of the Annual Total Electricity Requirement in Ireland across the four TES 2023 scenarios


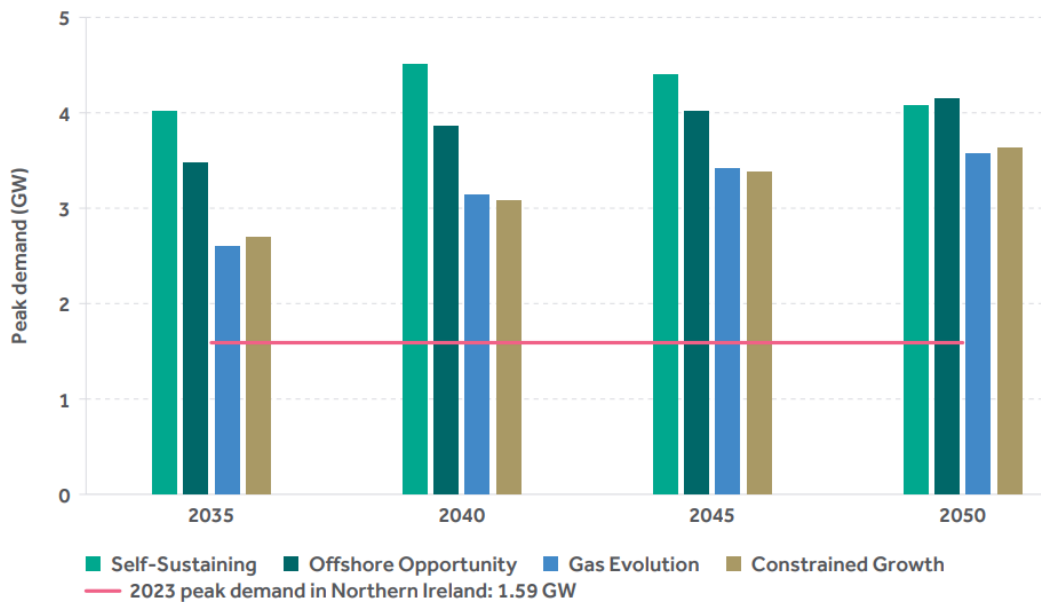
Source: EirGrid & SONI

Figure 17: Evolution of the Annual Total Electricity Requirement in Northern Ireland across the four TES 2023 scenarios


Source: EirGrid & SONI

Figure 18: Evolution of peak demand in Ireland across the four TES 2023 scenarios


Source: EirGrid & SONI

Figure 19: Evolution of peak demand in Northern Ireland across the four TES 2023 scenarios


Source: EirGrid & SONI

7.3.2 Generation

Ireland

Substantial renewable build is expected in all four scenarios, with installed capacities in 2050 ranging from 8-17 GW of solar, 9-37 GW of offshore wind, and 7-12 GW of onshore wind across the scenarios.

Storage is also expected to contribute significantly, with 38-140 GWh installed in 2050, depending on the role of long duration energy storage and vehicle to grid / demand side storage envisaged in each of the scenarios.

In all scenarios, with the exception of the "Gas Evolution" scenario, thermal gas plant continues to play a role on the power system out to 2050, with almost 6 GW remaining on the system at that time, Figure 20. In the "Gas Evolution scenario", it is assumed that gas units are converted to, or replaced by, hydrogen units by 2045.

The capacity factor of these gas generators is expected to decline to much lower levels over time as there will be increasing periods in which demand can be met by a combination of renewables, storage and interconnection. However, gas fired generation will still be needed in order to provide security of supply. The Self-Sustaining and Offshore Opportunity scenarios also see a role for hydrogen generation, but not one that leads to the displacement of thermal gas capacity.

While it is expected that biomethane will play a role in decarbonising the gas mix in both Ireland and Northern Ireland, indigenous supply is expected to be limited, and bioenergy is therefore expected to play a minor role in all scenarios.

Northern Ireland

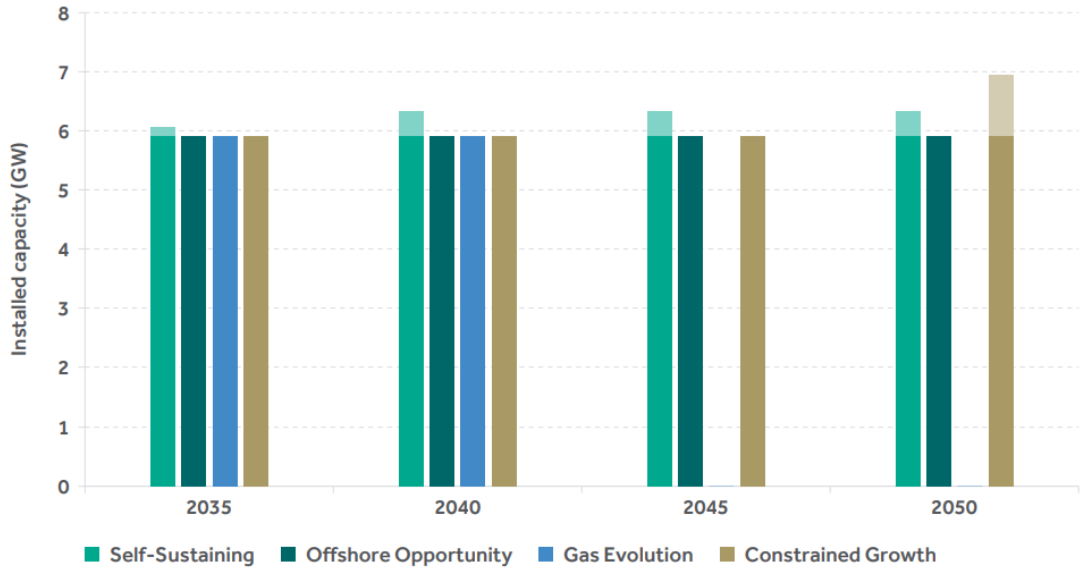
Substantial renewable build is also expected in Northern Ireland in all four scenarios, with installed capacities in 2050 ranging from 1-3 GW of solar, 2-4 GW of offshore wind, and 2-3 GW of onshore wind across the scenarios.

Storage will play a role, with 6-46 GWh installed in 2050, depending on the development of long duration energy storage and of vehicle to grid / demand side storage.

Similar to the Irish case, in all scenarios, with the exception of the "Gas Evolution" scenario, thermal gas plant continues to play a role on the Northern Irish power system out to 2050, with over 2 GW remaining on the system at that time, Figure 21. In the "Gas Evolution scenario", it is assumed that gas units are converted to, or replaced by, hydrogen units by 2045.

The capacity factor of these gas generators is expected to decline to much lower levels over time, but the capacity will still be needed in order to provide security of supply. The Self-Sustaining and Offshore Opportunity scenarios also see a role for hydrogen generation, but not one that leads to the displacement of thermal gas capacity.

Figure 20: Installed gas thermal generation capacities in Ireland (lighter colour denotes plants equipped with CCS).



Source: EirGrid & SONI

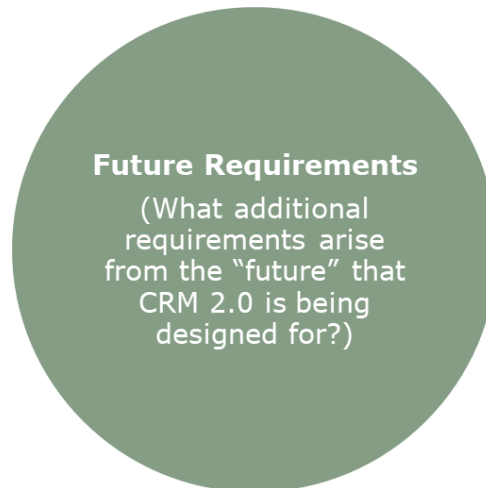
Figure 21: Installed gas thermal generation capacities in Northern Ireland (lighter colour denotes plants equipped with CCS).



Source: EirGrid & SONI

8 Review: Future Requirements

In Section 7, we have given an overview of electricity policy in Ireland and Northern Ireland, and of how the TSOs forecast that the electricity systems in both jurisdictions will evolve out to 2050. In this section, we now assess the development needs of the CRM taking into account this view of the future that the mechanism is being designed for. We examine the CRM through the following lens:



8.1 Current development needs

It is clear that the development of the future electricity system across the island of Ireland is dominated by the drive to decarbonise. There are dedicated instruments in place to secure investment in renewable generation capacity, in the form of the Irish and Northern Irish RESS schemes, while Carbon pricing provides a broader incentive to lower carbon emissions from power generation. And while the overriding objective of the CRM is not to drive decarbonisation, but to ensure security of supply, the development of the design should not be carried out in ignorance of this central policy aim. In developing CRM 2.0, opportunities to support **decarbonisation** should be sought.

Also in support of the drive towards net zero, the increasing role of **flexible capacity** as a complement to variable renewable generation is key. Once more, the CRM is not now, or expected to be in the near term, the primary means of ensuring sufficient flexibility, but the mechanism should be developed in alignment with this aim where possible. This relates particularly to non-fossil flexibility including explicit demand response, or DSUs, as well as storage.

These views regarding the development needs of the CRM from a forward-looking perspective, align with the outputs from the workshops held with each of the RAs, the TSOs and industry (see Sections 6.3, 6.4 and 6.5). In these workshops the forward-looking strategic topics raised included, prominently, both decarbonisation and the role of the CRM in supporting it,

as well as the suitability of the design for non-fossil flexibility (DSUs and batteries) going forward.

Relatedly, the changing nature of demand as a result of increased electrification and increased opportunities for demand side participation, means that implicit demand response is also an area that comes into focus when a forward-looking view is taken of the development needs of the CRM. The **mechanism for recovering the costs** of the CRM provides a tool to support implicit demand response and thereby facilitate the implicit flexibility needed to enable decarbonisation.

On this basis, we consider that, assessing the CRM through the “Future Requirements” lens, the priority areas that require development relate to decarbonisation, flexibility integration, and the cost recovery mechanism.

8.2 Potential future development needs

If we also take a step back and set aside the timeframe constraints of the State aid process, as well as the current technological limitations on the types of capacity available to participate in the CRM, we can consider the development needs of the market from a longer term and more strategic perspective.

Any market design is a compromise to meet the needs of buyers and sellers, and the details of the scheme will need to adapt over time to the characteristics and preferences of future energy users and future service providers.

The next iteration of the SEM Capacity Mechanism must continue to support a system which relies substantially on thermal generation capacity for security of supply. The design philosophy for CRM 2.0 is ‘evolution not revolution’, while allowing space for adaptation through future State aid approval to permit ongoing development within the framework of the approved scheme. This is consistent with the forward-looking views of the energy system, in which thermal (gas) capacity will play a dominant role in meeting the derated capacity adequacy needs for at least the next decade, with a still modest role for storage²³.

Looking further forward however, still within the effective window of CRM 2.0 (assuming 10-year contracts are available, with delivery able to commence as late as the early 2040s) there are many potential developments which could affect the fundamental design of the scheme, such as:

- Technology mix of the future system, which is substantially driven by the policy environment: including RES share (particularly offshore wind and solar), possible roles for hydrogen, biomethane or (subject to development of the legal underpinning) nuclear generation, Carbon Capture, Use and Storage (CCUS) and Bioenergy with Carbon Capture

²³ The AIRAA shows a modest growth in thermal capacity (~2% PA) to 2035, and a faster growth in installed battery capacity (~4% PA) before consideration of any changes in derating factors.

- and Storage (BECCS), and various forms of storage as well as additional interconnection;
- Developing needs for other types of system service including flexibility and stability, which may be available from the technologies that provide adequacy or which may need to be procured from other technologies;
 - Level, nature and timing of future demand growth, including electrification of domestic heating and transport as well as development of new electricity-dependent industries (data centres included);
 - Geographical and network deliverability constraints, including location-specific adequacy/flexibility needs and the risk that system needs become more spatially differentiated over time (and hence more difficult to address through a single procurement product);
 - Scale of demand flexibility – technical and societal – and the extent to which demand flexibility will contribute to adequacy through explicit (sale of a service) rather than implicit (autonomous, responding to price incentives) mechanisms;
 - Divergent needs for reliability for different types of load with different degrees of flexibility and commercial value (e.g. urgent data processing vs non-time sensitive EV charging);
 - (Consequent on the previous two) changes in the patterns of net demand (demand minus renewable generation); which are likely to lead to longer duration scarcity events at extended periods of low wind and/or solar radiation²⁴;
 - This in turn will lead to changes in the future marginal contribution of different technologies (currently recognised through derating factors which are set before the auction for the duration of the contract period) as the system evolves.

The underlying need for a capacity mechanism is to mitigate investor risk on the understanding that revenue volatility (price risk and volume risk) in an energy-only market is unmanageable. If more flexible demand-side resources are added to the system, and as smart metering and data-enabled demand response become more widespread, then customers may be able to mitigate much of the underlying volume risk – and perhaps even adequacy

²⁴ AFRY analysis in 2022 for NESO of the GB power system showed that the mean duration of a scarcity event increased from 5 hours in 2025 to between 21 and 58 hours in 2035 (dependent on scenario). The mean duration of lost load events increased from 4 hours (2025) to 6-9 hours (2035), with some events lasting a continuous 30-50 hours. The GB system has similar characteristics to Ireland, with wind generation becoming the dominant form of generation. <https://www.neso.energy/document/273781/download>, slide 32 and 33.

risk – through their own actions, using local storage (EVs and domestic batteries). The base assumption for a Capacity Mechanism – of shared reliability and a common value of lost load – may become increasingly invalid within the lifetime of CRM 2.0.

Against this background, some of the potential longer-term developments in the design of the SEM CRM are described below. These will not be part of CRM 2.0 but may merit a ‘watching brief’ (and perhaps a timetabled review at a future date) over the course of its lifetime.

8.2.1 Multi-year analysis

Technologies vary in their expected delivery time (and in their uncertainty of delivery time) and their expected economic life; and future technologies will diverge further. The system may become dependent on retrofits to decarbonise existing capacity. For new build contracts, the current CRM is centred on a T-4 contract with a duration of up to ten years for new capacity, with all analysis of economic value based on the first year. ILCs can be awarded for up to 5 years. On top of these, there are early delivery incentives, but these are not specifically tied to system need in particular years.

A more sophisticated approach would be to allow the bidders to offer a range of contract windows, with variation in the start year and contract duration. The auction would need to consider a range of years for the contracted delivery of the service, assigning higher economic value to the years with greater need. This would need to use a set of forward scenarios, going beyond the ten-year horizon of the ERAA / AIRAA. The auction would not seek to meet peak demand for every future year, but would need to place some value on precontracting demand for future years. The future values would need to make some assumptions of the cost of securing this capacity in later auctions, and could also be used to reflect uncertainty in future demand forecasts. If implemented well, this would allow the auction mechanism to trade off between early lock-in and deferral of procurement to meet uncertain future demand growth.

A lesser version of this would be to focus only on the earlier years for the start of contract delivery, but still to prioritise projects which could be delivered earlier if these are years with greater need.

A related development would be the use of forward-looking derating factors. We would expect derating factors to change over time as the system changes, especially resources with energy or other limitations on their availability (storage, capacity with environmental or other operating limits, and also some types of demand side resource). Fuel availability or systemic failure might become a relevant factor in future, e.g. for biomethane or even natural gas. If derating factors are the primary mechanism to allow different technologies to compete equally for long term contracts, it would be desirable to look at how these derating factors would evolve for the entirety of the contract delivery window, rather than just for the first delivery year. The auction process and the payments could then reflect this forward view (again taking account of alternative scenarios of system development). An alternative approach would be to reset the derating factor against which the

capacity is paid in each delivery year, but the risk imposed on investors would probably make this inadvisable.

8.2.2 Co-procurement covering other system needs

If two products (e.g. “capacity” and “flexibility”) are procured through separate, unlinked auctions, bidders that require both revenue streams will include a risk premium in their bids into the first auction to reflect the uncertainty of clearing the second auction; consumers ultimately pay for that risk premium. If the project subsequently receives revenue from the second auction, there may be some over-recovery, and failure to clear in the second auction might result in a risk that the project fails to proceed. This can be seen as a “two-auction misalignment risk”.

In the near term, EU market design reforms place increased emphasis on Flexibility Needs Assessments (FNAs) as a planning tool to identify future flexibility requirements and (where justified) to inform indicative national objectives for non-fossil flexibility and the potential use of Non-Fossil Flexibility Support Schemes. When the FNAs are available for Ireland and Northern Ireland, they will provide an evidence base for decisions on whether (and how) any Non-Fossil Flexibility Support Scheme should be progressed. There is a strong interaction between the provision of flexibility and capacity.

Over time, it is plausible that FNA approaches converge with the methodologies used to diagnose resource adequacy, including the European Resource Adequacy Assessment (ERAA), given the explicit conceptual linkage between flexibility needs assessment and adequacy assessment in EU-level framing.

If flexibility and adequacy diagnostics become more aligned, some Member States may explore more integrated forward procurement of “flexibility” and “adequacy” attributes, particularly where investment decisions increasingly rely on stacking multiple revenue streams rather than treating operability services as incidental.

We consider that the SEM should be a monitor / fast follower of such developments rather than a first mover, given the complexity of redesign and the need to preserve delivery confidence under CRM 2.0 implementation constraints.

Similar “stacking and alignment” issues could also arise in relation to system services procurement under FASS as technologies increasingly co-produce adequacy, flexibility and stability attributes. FASS is centred on daily procurement (DASSA), complemented by a Layered Procurement Framework for longer-term contracting (up to 12 months) and (where required) separate fixed-term procurement frameworks during transition or for specific capabilities. Multi-year fixed-term contracting could be considered for specific services if justified by system needs and investment requirements. Any move toward combined procurement that explicitly integrates capacity and system services requirements would represent a more fundamental market design evolution beyond the current FASS decisions and beyond CRM 2.0 as presently envisaged.

Aligning procurement with the outputs of the FNA and ERAA/AIRAA²⁵ could be achieved through combined forward co-procurement of flexibility and adequacy (“integrated reliability procurement”). A single forward process could procure an optimised bundle of adequacy and flexibility attributes. This would represent a material change in governance and market design (product definitions, qualification, settlement, and obligation/penalty treatment across attributes) and would cut across existing institutional roles and code frameworks.

8.2.3 Accommodation of more radical technologies

Under some of the TSOs’ future scenarios for Ireland and Northern Ireland, the reliance on existing thermal (gas) capacity for adequacy is superseded by hydrogen plant. Other ultra-low carbon technologies could become important in meeting energy and capacity needs in the longer term depending on policy and technological development – nuclear, long duration energy storage, BECCS, etc.

We consider that for each of these technologies, a Capacity Mechanism is unlikely to be a suitable instrument on its own to underpin investment decisions. For some (biomethane, hydrogen, BECCS), the technologies would naturally sit far out in the merit order and they would need support for production as well as capacity (e.g. UK power CCUS: Dispatchable Power Agreement (DPA)).

In the longer term there could potentially be a more holistic procurement of a set of technologies with centrally-determined volumes, but this would be a much more centrally planned investment regime than anything currently implied for Ireland or Northern Ireland.

For small scale nuclear, the overall capital cost is likely to require a more fundamental mechanism for state support (as in the UK and other countries). Given the long lead times, development and construction risk and overall project life, a ten-year capacity contract would only underwrite a very small part of the overall project capital cost, and we do not consider that any form of CRM would be suitable.

As noted above, in respect of the “two-auction misalignment risk”, it is not efficient for projects requiring significant investment to participate in two separate (uncoordinated) auction schemes which are essential to their investment decision.

We consider that for technologies relying on separate long-term support schemes, the cleanest coordination rule may be exclusion from the Capacity Mechanism (or mandatory exit), avoiding double remuneration and the mispricing that arises when investment cases depend on uncertain revenue stacking across unlinked instruments; GB excludes otherwise supported generation (e.g. RO or CfD/FiT supported generation) from the Capacity Mechanism.

²⁵ This could conceptually apply to any future long-term procurement of other system services.

The nature of demand side flexibility will evolve with electrification and ongoing digitalisation. Today's capabilities and challenges for real time demand monitoring and control will likely be antiquated in the coming decade. It is very likely that whatever future-proofing is put in place for CRM 2.0 for demand side participation, it will be ripe for substantial reform before the end of the scheme.

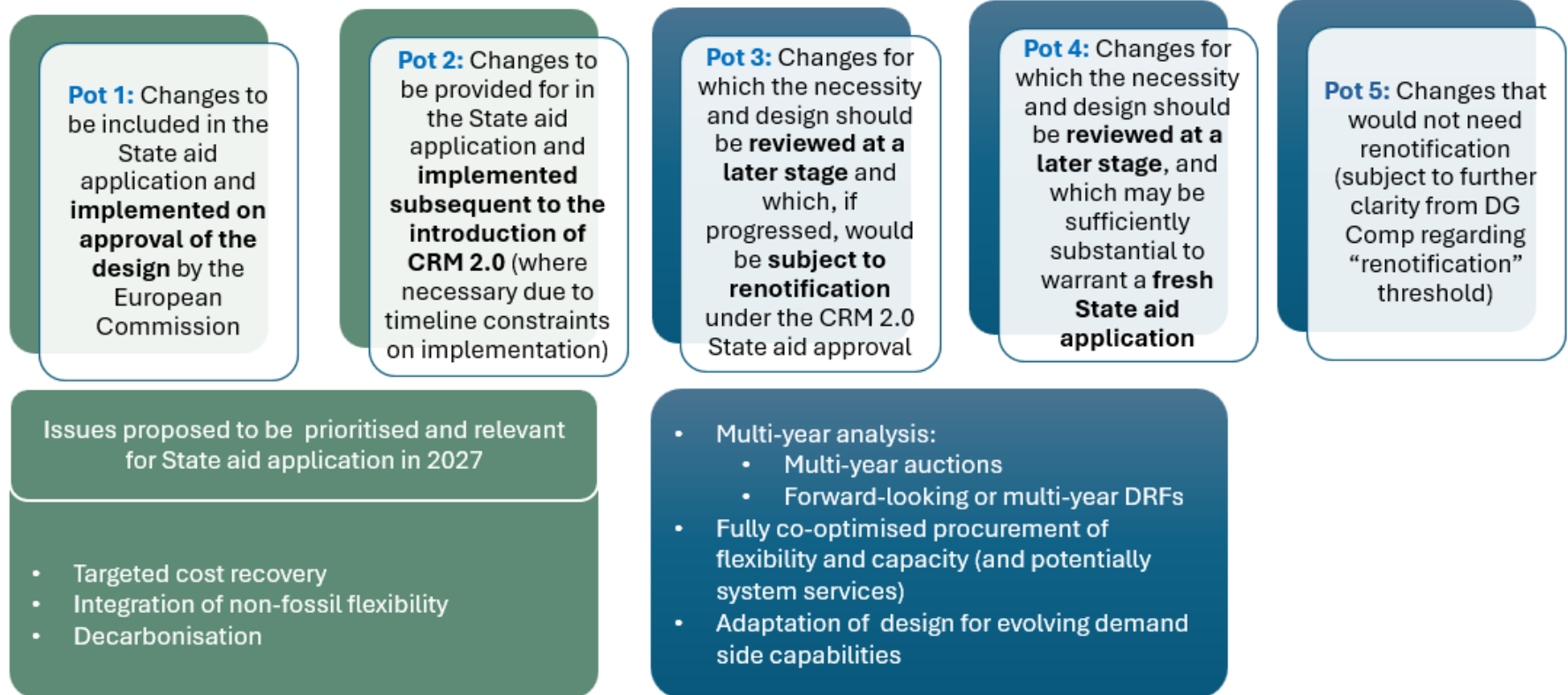
For State aid approval of a market-wide Capacity Mechanism, there is a requirement to demonstrate that strategic reserve would not resolve the adequacy problem. We have explored whether there is a longer-term future using a Non-Fossil Flexibility Support Scheme to bring on new investment in zero carbon capacity complemented by a strategic reserve to maintain a tail of thermal fossil capacity, without a market-wide payment. Although this was a useful thought experiment, the nature of strategic reserve is that it must be excluded from the market, and at times when it is needed the (imbalance) price is intended to rise to VOLL. In practice it is hard to envisage circumstances in which residual thermal capacity is needed so infrequently as for that to be an acceptable outcome.

8.3 Conclusion

When assessing what development needs arise from the future that CRM 2.0 is being designed for, the key areas we identify align with some of those that stem from the requirements of legislation and State aid i.e. decarbonisation, integration of non-fossil flexibility and targeted cost recovery. These fall in Pots 1-2, Figure 22.

In addition, however, when we consider the further potential evolution of the electricity system and market over time, including over the lifetime of CRM 2.0, there are other potential changes that could be beneficial or necessary, and that should be kept in mind. These include multiyear analysis in the context of both auction volumes and derating factors, co-procurement of capacity and other services or products, and further adaptation to accommodate the evolving capabilities of the demand side. These potential development areas sit in Pots 3-4.

Figure 22: Classification of CRM development needs based on assessment of requirements of the future electricity system across the SEM.



9 Review: Areas where Change is recommended

In this section, we summarise the areas of the CRM design in which we recommend progressing changes. These areas have been identified bearing in mind the practical constraints imposed by the timeframe for the new State aid application (to take place in H1 2027) and the design philosophy set out in Section 3 of this report i.e.:

1. **“Evolution, not revolution”**: CRM 2.0 should be an evolution of the current CRM, rather than a radically changed mechanism.
2. A **dynamic approach to State aid approval** should be taken, allowing continued evolution of the CRM over the lifetime of the next State aid approval by:
 - a. building flexibility into the State aid approval where possible and useful, and
 - b. planning for development of the CRM during the 10-year period even where State aid renotification is required.

We have prioritised those areas relevant for compliance with the requirements of the EU legislative framework and thereby facilitating a smooth State aid approval process. We note however that many of these changes driven by compliance requirements correspond to the development areas we have also identified from the perspective of the future development of the power systems within the SEM. This reflects the fact that the direction in which the EU framework is driving CRM design aligns in many respects with the direction of Northern Irish and Irish energy policy.

In addition to these changes required for compliance purposes, we also prioritise two further changes driven primarily by key challenges that have been evident in the operation of the CRM to date.

This suite of prioritised changes is classified into Pots 1 and 2 i.e. constitutes the proposed scope of the design work to be progressed in time for inclusion in the State aid application in H1 2027.

Separate to these areas in Pots 1 and 2, we also set out changes that could be considered over the lifetime of CRM 2.0, which would likely require re-engagement with the State aid authorities, either through a “renotification” process or a fresh notification (to the extent that these differ). These are areas where we expect the case for change may become stronger over time and/or where the magnitude of the change makes design development within the State aid approval timeframe unfeasible.

Finally, in Pot 5, we identify a number of areas which have been highlighted in our review as important for development, but in which we believe change could be progressed without requiring engagement with the European Commission. For this reason, these changes have not been included within the scope of the design work to be progressed in time for the State aid application.

The recommended areas for development across the five pots are summarised in Figure 23, with each one explained in what follows of this section, along with the rationale for their classification into the given pot.

9.1 Pots 1 and 2

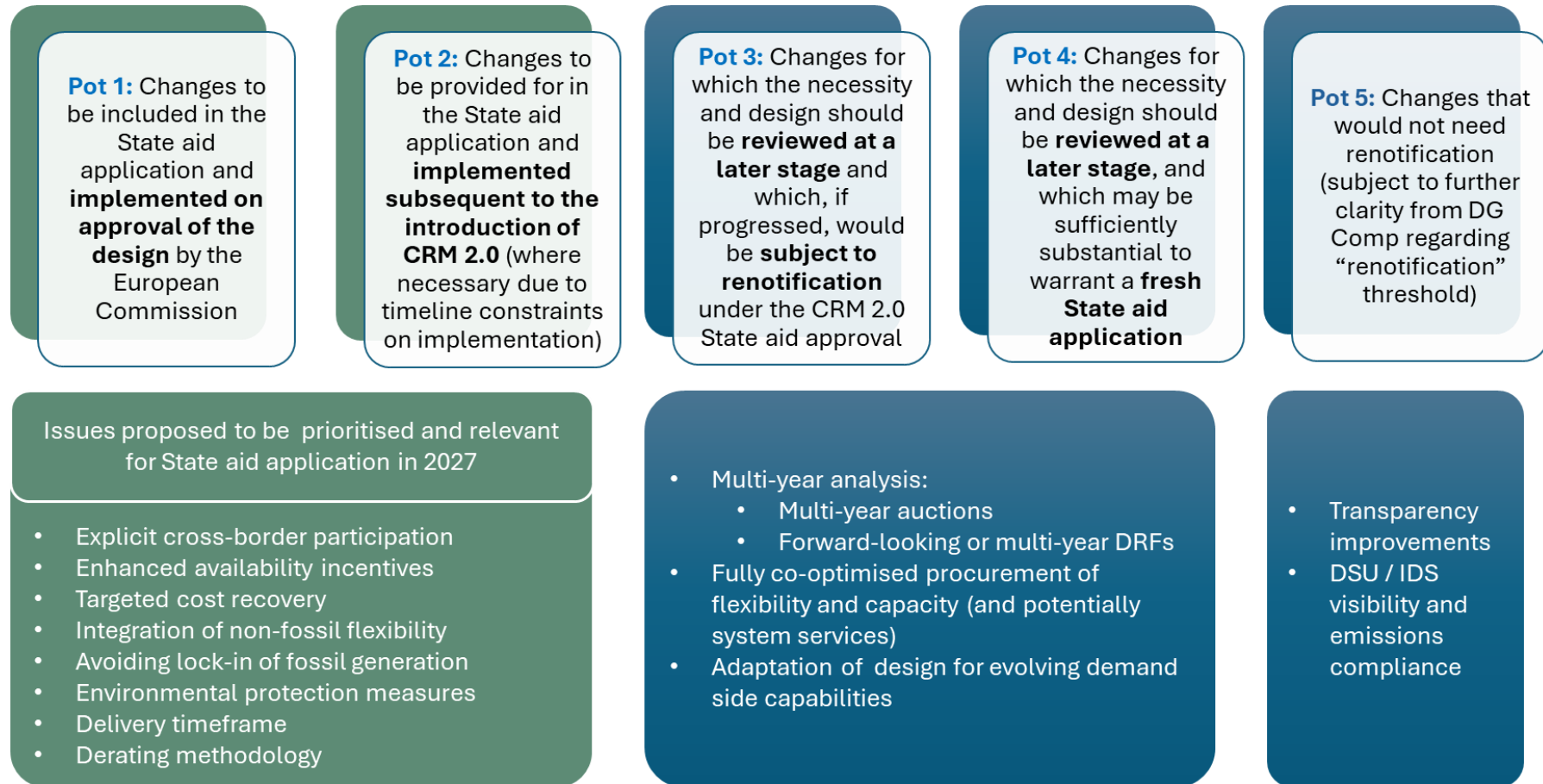
Pots 1 and 2 comprise those areas recommended to be developed in time for the State aid application in H1 2027. We do not distinguish between the two pots (i.e. between changes that would be implemented immediately on approval by the EC and those that would be implemented subsequently) at this time, as that distinction will ultimately need to be informed by an assessment of the required implementation time once the design is developed.

Explicit cross-border participation is a clear requirement of EU legislation and one on which we understand the RA teams have been engaging with the EC in the context of the existing CRM. The work to implement this is well underway²⁶ already, separate to the scope of our work. As such, for completeness we have included this as a compliance requirement, but we do not consider it further in this review.

The need to develop **enhanced availability incentives** is driven by a combination of the requirements of EU legislation and our assessment that in practice, the RO in the SEM CRM has not to date constituted a sufficient incentive. Changes to the existing incentive framework for capacity providers to be available would include sharpening the RO and/or supplementing it with additional measures to incentivise availability, or penalise non-availability, at times of system stress.

A more **targeted cost recovery** mechanism would bring the SEM CRM into closer alignment with the intent of EU legislation. It would also adapt the CRM for a future in which implicit demand response is expected to play a crucial role in the provision of flexibility. There are two ways in which we consider the cost recovery mechanism could be further targeted. Firstly, it could be targeted at particular times when the system margin is tight i.e. “temporal” targeting. This is what is envisaged in CISAF (though recognising that CISAF is not a hard constraint). Secondly, it could be targeted at the locational capacity constrained areas in proportion to the cost associated with those areas i.e. “locational” targeting.

²⁶ [SEM-25-071 Explicit Cross-Border Participation Consultation | The Single Electricity Market Committee](#)

Figure 23: Development needs of the CRM identified in this review.


The **integration of non-fossil flexibility** (including demand response and storage) into the CRM is a requirement of EU legislation, which has become stronger and more explicit as the legal framework has developed. It is also an important consideration from the point of view of the future system the CRM is to help deliver on the path to net zero. Here, we envisage that this specific item would involve:

1. Allowing for the capacity contribution of flexibility procured through other existing, or to be developed, mechanisms, when determining the capacity requirement for the CRM auctions; and
2. Providing for a minimum flexible volume constraint, aligned with the outcome of the FNA(s), to apply in the CRM auctions.

In addition, however, non-fossil flexibility can also be accommodated, or encouraged, less directly through a number of other development areas that we prioritise here. These are, specifically, the choice of a top up auction timeframe adapted to non-fossil flexibility project delivery timelines, and the development of the DRF methodology as required to appropriately reflect the adequacy contribution of energy limited units (included non-fossil flexibility). These two items are described more fully later in this section.

Avoiding the lock-in of fossil generation and introducing **environmental protection measures** are both driven by the requirements of the State aid framework, while also aligning with the intended future development of the electricity system. The introduction of ILCs by the SEM Committee²⁷ went some way towards mitigating the risk of lock-in, while SEM-25-070²⁸ consulted on options to explicitly decarbonise the CRM and thereby support environmental protection. The main decarbonisation options considered were the Green Scalar and the Green Bonus, with the Green Scalar broadly preferred by respondents. This would be a multiplier applied to the Capacity Payment Price based on a unit's carbon emissions intensity, thereby incentivising lower-carbon technologies.

The challenge to decarbonising the CRM currently is the absence of fully decarbonised technologies that can participate at scale and substantially satisfy the capacity requirement, while measures to encourage small scale environmental benefits run the risk of overcompensation. However, this is a key item from the point of view of both national policy and EU legislation, and we recommend it is progressed within the Pot 1 and 2 scope, recognising the potential to make provision for a decarbonisation measure that can then be activated later in the lifetime of CRM 2.0 as appropriate in light of technology, and broader, developments.

Finally, the overlap between non-fossil flexibility integration and environmental protection measures is worth noting, in that increased participation from non-fossil flexibility will have a decarbonising effect.

²⁷ [SEM-24-035 Intermediate Length Contract Decision Paper | The Single Electricity Market Committee](#)

²⁸ [SEM-25-070 Consultation Decarbonisation of Existing CRM v300 For Publication 0.pdf](#)

A review of the **delivery timeframe** is driven by the assessment of the challenges with the CRM to date. While not a compliance requirement, we nonetheless consider it to be a priority for inclusion in the State aid application in H1 2027. This would follow on from the work on auction timeframes already commenced by the SEM Committee²⁹ and would include an assessment of the optimum timeframe for the main auctions (T-5 or T-6 effectively) as well as the optimum timeframe for the top up auction, taking into account the delivery timeframes of different technologies.

The final item proposed to be included in the scope of the design development for the State aid application is a review of the **Derating methodology**, particularly in terms of its suitability for non-fossil flexibility and its alignment with the ERAA. The need to align the DRF methodology with the ERAA stems from CISAF, and as such is linked to compliance requirements. However, broader questions about the methodology in terms of its suitability for DSUs and storage in particular arise from both a review of challenges with the CRM to date (as reflected by recent modifications raised) and a forward looking assessment of the types of technology that the CRM will increasingly need to accommodate as the system transitions to net zero. We understand that the TSOs have commenced work on the development of a new tool for calculating DRFs, as there are limitations within the existing ISAC tool when applied to energy limited units, amongst other things. We also understand that they are investigating options for unit-specific DRFs, in follow on to commitments made by the SEM Committee in their decision on related code modifications previously raised by industry.

9.2 Pots 3 and 4

Pots 3 and 4 contain possible changes that could be considered over the lifetime of CRM 2.0, which would likely require re-engagement with the State aid authorities. These are in areas where we expect the case for change may become stronger over time and/or where the magnitude of the change makes design development within the State aid approval timeframe unfeasible. It is possible, as development work progresses on the areas contained in Pots 1 and 2, that some of these areas may move into Pots 3 and 4.

The first item that we see value in reviewing the need for at a later stage is **multi-year analysis**. This would encompass two aspects:

1. **Multi-year auctions** would allow bidders to offer a range of contract windows, with variation in the start year and contract duration. The auction would need to consider a range of years for the contracted delivery of the service, assigning higher economic value to the years with greater need. If implemented well, this would allow the auction mechanism to trade off between early lock-in and deferral of procurement to meet uncertain future demand growth. This could

²⁹ [Options for the timings of upcoming CRM auctions \(SEM-26-003\) | The Single Electricity Market Committee](#)

improve the cost efficiency of the mechanism and help to mitigate the risk of non-delivery.

2. A **forward-looking multi-year DRF methodology** would allow the evolution of DRFs over the full term of a multi-year contract to be accounted for. Alternatively, the derating factor could be reset for each year of a multi-year contract, though this would impose considerable additional risk on investors. The variation in DRFs over a multi-year contract term is likely to increase going forward, particularly for energy-limited units, which are associated with cannibalisation and saturation effects in terms of their capacity contribution.

The second item we see a likely need to review during the lifetime of CRM 2.0 is a more integrated approach to the procurement of flexibility and capacity. In Pots 1 and 2, we have included the potential provision of a minimum volume requirement for flexible capacity in the CRM. This could in principle evolve into a fully **co-optimised procurement of capacity and flexibility** in time, as the FNA and the holistic approach to meeting the needs identified in it become established. This could even be developed further into the concept of co-optimised procurement of capacity, flexibility, and long-term system services (where the intent is to incentivise *new* investment in system services, and to the extent that flexibility and system services are treated as discrete).

Finally, we see a need to keep the design under review in terms of its **suitability for demand side participation**. The capability of the demand side to provide flexibility, and potentially contribute to the adequacy needs of the system, is expected to evolve significantly with electrification and ongoing digitalisation.

9.3 Pot 5

In Pot 5, we identify areas highlighted in our review as important for development, but in which we believe change could be progressed independent of the State aid process. For this reason, these changes have not been included within the scope of the design work to be progressed in time for the State aid application (i.e. Pots 1 or 2).

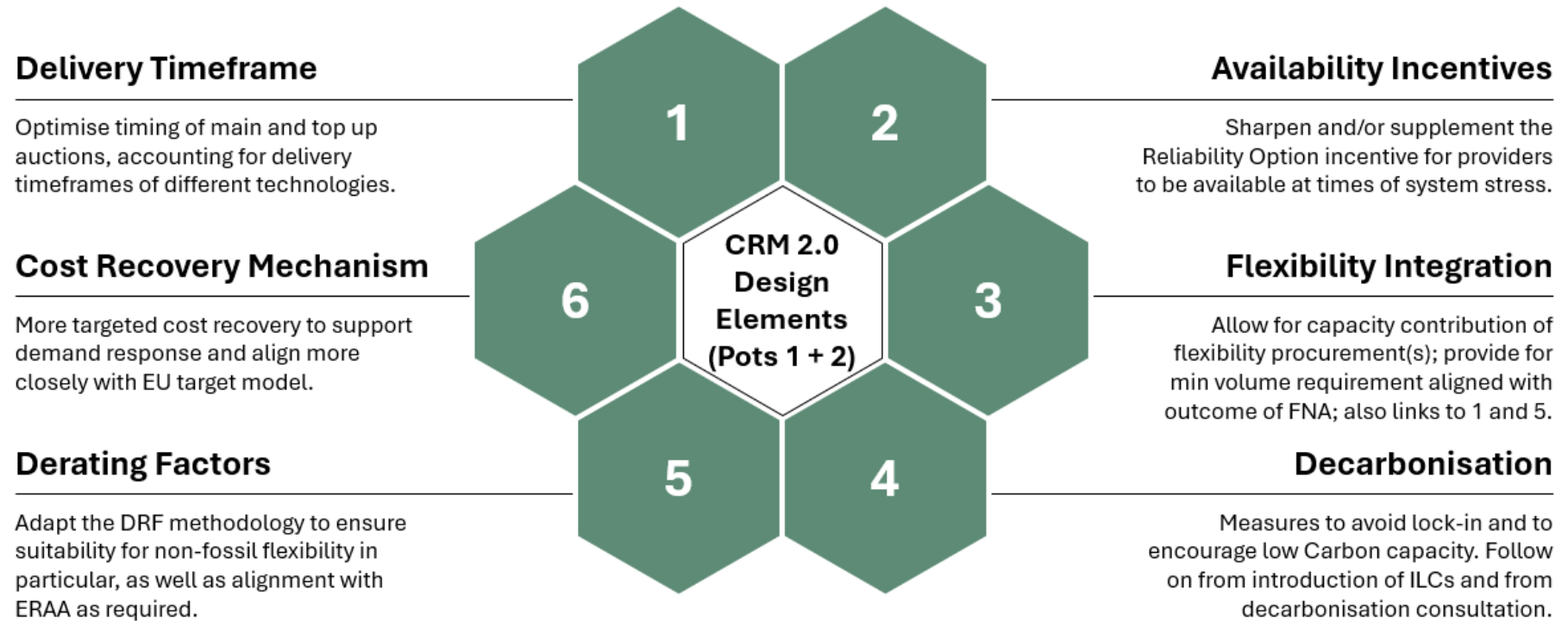
Based on the review of challenges with the current CRM, increased **transparency** is an area that may benefit from development, particularly as related to the volume setting process and to the publication of information on extensions and terminations.

Secondly, a range of issues related to **DSUs** as they interact with the current CRM design have been highlighted. Some of these are proposed for progression in Pots 1 and 2 insofar as they align with measures to integrate non-fossil flexibility. Others however, interact with ongoing work on DSU energy payments, which is a parallel workstream. Further issues relate to visibility of the composition of DSUs. We consider that these can be addressed through the development of the CRM reporting and monitoring processes, independent of the State aid approval.

9.4 Conclusion

From the items contained in Pots 1 and 2 (i.e. those relevant for the State aid application in H1 2027), we have consolidated six proposed design elements, leaving aside explicit cross-border participation which is being progressed separately, and combining environmental protection measures with the need to avoid lock-in of fossil generation under the heading “decarbonisation”.

The development needs of the CRM identified through each of the lenses assessed in this review are therefore summarised in the form of the six design elements shown in Figure 24. It is proposed that the design in these six areas be developed for inclusion in the State aid application in H1 2027.

Figure 24: Proposed elements of the design phase of CRM 2.0.


10 Design: Delivery Timeframe

10.1 Responses to SEM-26-003

The SEM Committee’s consultation³⁰ and decision³¹ on “Options for the timings of upcoming CRM auctions” focused on the remaining auctions within the lifetime of the existing CRM. The consultation did however also request respondents’ views on a move towards T-5 auctions in the context of the CRM Development Programme and the new State aid approval.

Most respondents supported a move to T-5 auctions in the longer-term, considering this timeframe to be more aligned than T-4 with the timeframe for planning and grid connection across the SEM.

10.2 Overview of timelines in other countries

While the development timeframe of different technologies will vary to some extent from country to country, it is nonetheless instructive to consider as context the capacity auction timeframes across other European markets. An overview of these timeframes is given in Table 8.

| Market | Auction Timeframe |
|---------|-------------------|
| France | T-4 |
| | T-1 |
| Belgium | T-4 |
| | T-2 |
| | T-1 |
| Italy | T-4 |
| | T-1 |
| GB | T-4 |
| | T-1 |
| Poland | T-5 |
| | T-1 |

Table 8: Capacity auction timeframes in other European markets.

The timing of the main auction is predominantly T-4, although in Poland T-5 auctions are held. All markets that we assessed include a T-1 top up auction. We note that in

³⁰ [Options for the timings of upcoming CRM auctions \(SEM-26-003\) | The Single Electricity Market Committee](#)

³¹ <https://www.semcommittee.com/publications/options-timings-upcoming-crm-auctions-decision-paper-sem-26-024>

Belgium, a T-2 auction has been introduced to accommodate battery storage in particular.

10.3 Analysis of capacity delivery to date

We have carried out an analysis of the delivery progress of new capacity awarded to date under the SEM CRM. For this purpose, we have only considered the delivery years up to and including the 2025/26 capacity year as capacity awarded for subsequent years is not yet due for delivery.

Figure 25 shows the proportion of awarded new capacity for each auction timeframe that has either been delivered, extended or terminated. The data is further broken down by technology into Gas Turbine/DSU/Other Storage as the optimal delivery timeframes will differ, to a greater or lesser extent, across these different technology types.

If we consider the main auction to begin with, T-3 appears to be too short a timeframe for Gas Turbine capacity to deliver going forward, with over 75% of the capacity awarded to these units having now been either terminated or extended. Interestingly, a similar proportion of DSU capacity awarded at this timeframe has also been either extended or terminated. However, the total amount of DSU capacity awarded at T-3 is very small (41 MW) and may not be representative, therefore. Just over 20% of Other Storage capacity awarded at this timeframe has been terminated.

At T-4, 55% of the Gas Turbine capacity awarded has terminated, while ~25% of DSU capacity and ~30% of Other Storage capacity has also terminated. This supports the view that, going forward, a T-4 is also too short a timeframe for delivery of gas projects in the SEM. We consider that this, in combination with the views expressed by respondents to SEM-26-003 and taking into account the international precedent of the main auction being held at T-4 or T-5, supports the move to T-5 as standard for CRM 2.0. We note that CISAF requires the main auction to take place 4-6 years ahead of the delivery window, and that a T-5 auction is therefore in line with this framework.

Considering next the timing of the top-up auction, some gas capacity was awarded at the T-1 timeframe and delivered. However, the circumstances of this capacity were exceptional in that these projects were already very well advanced at the time they participated in the relevant auction. It is a safe assumption that more generally, T-1 is not a timeframe in which thermal capacity can deliver. For DSUs, almost the same amount of new capacity has been awarded at the T-1 timeframe as at the T-4 timeframe. However, the termination rate for DSU capacity awarded at T-4 is five times as high as that at T-1. Across all auction timeframes, the highest delivered proportion of DSU capacity occurs in the case of the T-1. This suggests that T-1 is the optimal timeframe for DSU capacity to contract with their constituent Individual Demand Sites (IDS).

For Other Storage, the picture is less clear. Unlike DSUs, storage projects require grid connection and are therefore tied to the timelines for the connection process, as well as their own construction timelines. They also require planning permission. However, unlike thermal plant, they do not require gas connection, their consenting processes are less onerous, and their planning processes may be less subject to appeal for example. The data shows the highest termination rate at T-4, and the lowest termination rate at T-1, but the range is relatively narrow, at 20-30% across all auction timeframes (ignoring T-2 given the very low volume of new storage capacity awarded at this timeframe) and the amount of new storage capacity awarded at T-1 is relatively low (up to the 2025/26 year).

On the basis of the data currently available, we consider that a main auction at T-5 and a top up auction at T-1 should accommodate battery storage, but we recommend keeping the optimal timeframe for batteries under review as more data becomes available on the termination, extension and delivery rates for these units.

10.4 Other considerations

State aid

The T-5 and T-1 timeframes are consistent with the CISAF framework, which includes a requirement for market-wide capacity mechanisms that:

"One main competitive bidding process for 75%-90%³² of the estimated target demand for the delivery window should take place 4-6 years ahead of the delivery window. Adjustment competitive bidding processes can be organised closer to delivery, taking into account the lead time for developing demand response and storage."

Forecasting

A move to a longer timeframe main auction will necessarily mean less certainty in forecasting capacity requirements as assumptions on demand level, amongst other things, will be made further out in time. However, the lower risk of capacity termination due to the longer delivery timeframe should have a countervailing effect in that it will reduce the uncertainty regarding delivery of pipeline capacity.

The T-1 will need to cover upward variation in the forecast capacity requirement for a given year, while also providing an opportunity for DSUs to participate at a timeframe that is optimal for them, particularly as a T-5 main auction may be more challenging for DSUs than a T-4.

Volume split across auctions

In terms of the volume to reserve from the main auction for the T-1 timeframe, with the intent of facilitating non-fossil flexibility in particular, the CISAF requirement above effectively means that this reserved volume should be in the range 10%-25%. The range chosen should allow an appropriate balance to be struck between ensuring security of supply and facilitating non-fossil flexibility (in particular demand response), as well as making allowance for uncertainty in the forecast capacity requirement at the time of the main auction.

We note the requirement that where cross-border capacity is not eligible to participate in the main auction, the maximum entry capacity calculated for the purpose of cross-border participation must be reserved, in addition to at least 10% of the estimated required volume. We also observe that the same amount of DSU capacity was awarded at T-4 as at T-1 for the auctions represented in **Figure 25**, albeit that there was a higher termination rate at T-4. This means that T-1 is not the exclusive route to a capacity contract for DSUs, despite appearing to be the optimal timeframe.

³² If cross border capacity is not eligible to participate in the main auctions, at least 10% of the estimated volume required for the delivery window plus the maximum entry capacity must be demanded in the adjustment auctions.

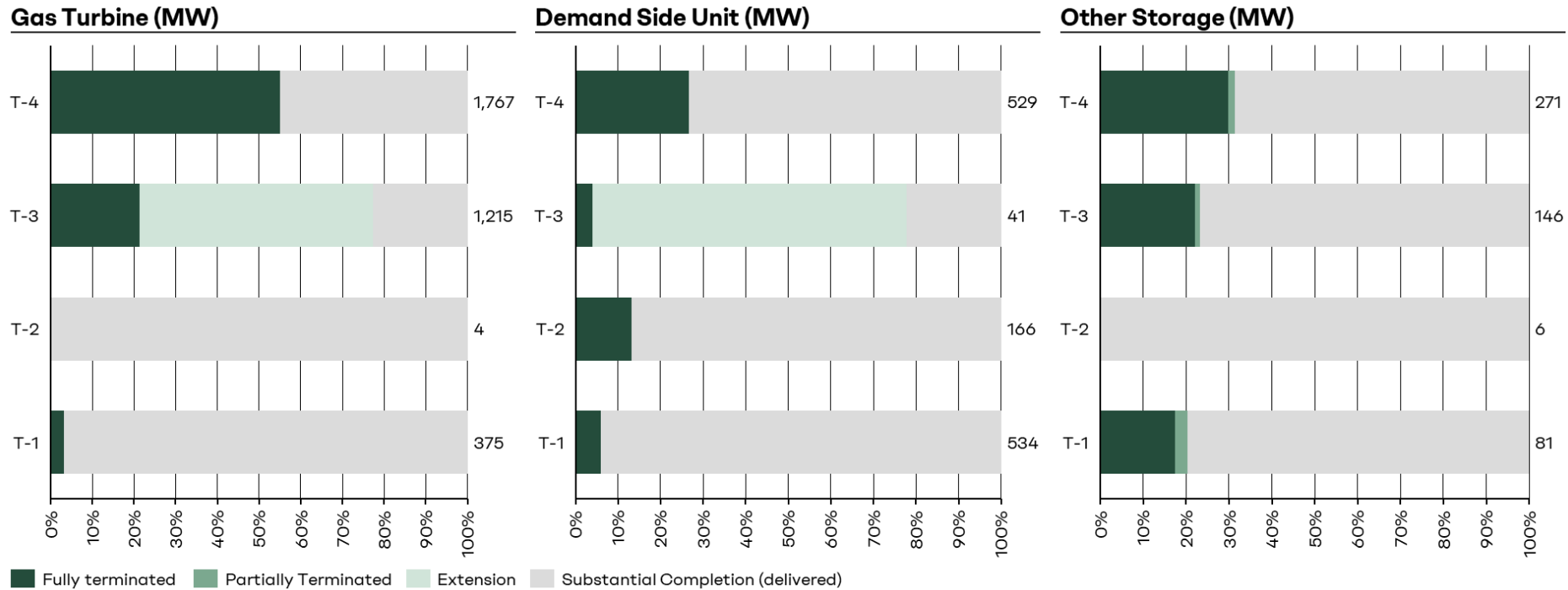
Given these considerations, we believe that it may be appropriate for a lower minimum bound than 10% to be applied to this range of reserved volume, while targeting a range, rather than specifying a single %, would allow the SEM Committee some room to judge the appropriate MW amount of reserved capacity given the context of a given auction.

10.5 Recommendations

On the basis of the above, our recommendation is to move to a T-5 timeframe as standard for the main auctions under the CRM 2.0 State aid approval. The top up auction should remain a T-1 as standard, with volumes to be reserved for this auction in a range of up to 25% of the T-5 capacity requirement.

However, we also advise that the optimal timeframe for delivery of battery storage should be kept under review in case an intermediate timeframe may be better suited to this technology type. If another timeframe were to be introduced, then consideration would need to be given to how to distribute the reserved volume from the main auction across multiple top up auctions.

Finally, the terms of the State aid approval should ideally allow the flexibility to hold other timeframe auctions if this becomes appropriate over the lifetime of CRM 2.0, be that for the purpose of facilitating battery storage based on the review referred to above, or for other reasons that may arise.



Note: Auctions for future delivery periods have not been considered.

Figure 25: Proportion of new capacity delivered, extended and terminated for gas plant, DSUs and battery storage.

11 Design: Enhanced Availability Incentives

11.1 Sharpening the RO

We have considered the option of sharpening the existing availability incentive framework by amending the operation of the Reliability Option (RO) and Administered Scarcity Pricing (ASP). However, the SEM Committee has recently examined the operation of ASP and modified the mechanism³³, with the implementation currently in progress. For this reason, we do not propose any further amendments to the existing framework.

We do note however the potential remedy identified by EY in their 2022 review in relation to interconnector actions:

"Refining the principle of flagging interconnector actions from SEM BM prices to drive prices that are more likely to exceed the RO strike price are and more reflective of the value of generation."

While this is outside the scope of the CRM Development Programme itself, relating instead to price formation in the energy market, we do support the idea of allowing interconnector trades to feed into pricing, as they are representative of the value of energy at the given time.

11.2 Supplementing the RO

As an alternative to amending the existing availability incentive framework constituted by the RO and ASP, we have considered the possibility of a supplementary mechanism that would broaden the reach of availability incentives beyond the periods of most extreme system conditions in which the RO will trigger. The exposure of capacity providers to unavailability charges during these periods should be correspondingly lower than their exposure under the RO during more extreme periods.

11.2.1 Availability monitoring and charging regime

If we think about enhancing incentives for availability, we need to determine which periods are relevant and to be targeted. When are capacity market units (CMUs) needed on the system and when should there be an obligation on them to be available at these times?

The answer to this is not simple. It is accepted that CMUs will not be available at 100% of their nameplate capacity throughout the year, due both to planned and unplanned outages, and to run-time constraints for energy-limited units. Derating Factors (DRFs) are applied in capacity mechanisms to reflect these limitations on the availability of participating units, but these are calculated probabilistically and will not relate to the contribution of any actual CMU in any year.

³³ [SEM-25-029 ASP Decision Paper.pdf](#)

The DRF methodology in the SEM CRM is based on the sum of the reduction in Loss of Load Probability (LoLP) in each period that arises due to the addition of a MW of a given technology to the system. The assumed adequacy “value” of each technology therefore takes into account the contribution of that technology over all periods. This could be taken to imply that CMUs are expected to be available in all periods. However, the LoLP is not equal in all periods, but depends on the capacity margin of available generation over demand (or the margin of firm capacity over net demand)³⁴. The LoLP value rises exponentially as the margin falls to zero, Figure 26.

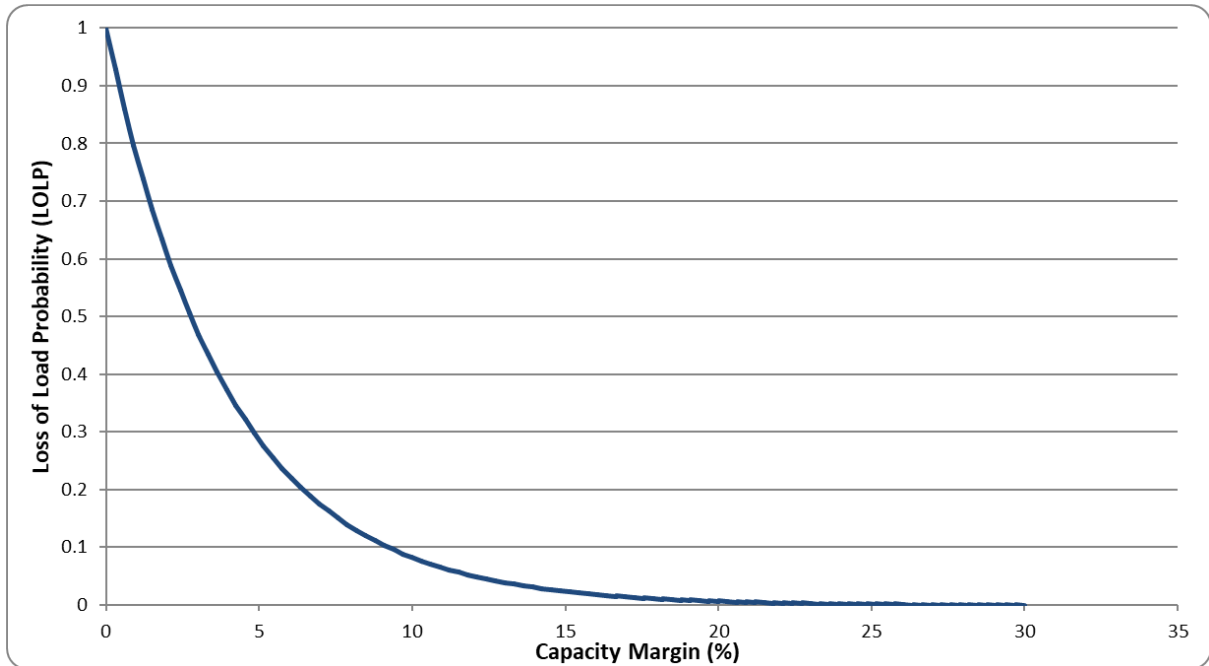


Figure 26: Illustrative example of variation in LoLP as a function of the capacity margin expressed as a %.

The economics of scarcity mean that there are some periods in which it is more important than others that a CMU is available to the system. In effect, these are the periods in which the system is “scarce” and the LoLP is high. These are also therefore the periods in which the availability incentives within the CRM should be targeted. There are different ways to identify these scarce periods. In principle, the price in the energy market should reflect the scarcity of capacity – rising beyond marginal cost levels as the LoLP rises, to the point where the price of energy reaches the maximum level that consumers are willing to pay before they reduce their demand i.e. the Value of Lost Load, or VoLL.

In practise, this degree of scarcity pricing is not seen in some energy markets, including the SEM, and the fact that the price does not rise to these levels leads to a situation where there is insufficient revenue available from the energy market to allow the continued operation of units on the system and to underpin new

³⁴ Price-based capacity mechanisms (such as in the predecessor SEM) attempt to assign a capacity value to each settlement period based on estimates of scarcity in that period; but under the present quantity-based design, the delivery period for CMUs is the contract year (beginning 1st October), with no natural subdivision.

investment when needed. This “missing money” is the basis for the implementation of a Capacity Mechanism, the principal purpose of which is to fill this revenue gap.

However, the price in the energy market will to some extent relate to capacity scarcity, with more expensive units being dispatched as the capacity margin decreases, and participants also potentially choosing to reflect some degree of scarcity in their bids. This is the basis for the operation of the RO in the SEM, where the strike price is set at a level corresponding effectively to the (estimated) maximum marginal cost of a CMU. At market prices above this level, CMUs must pay back any revenue they earn (or would have earned if running) in respect of their obligated capacity. Essentially, they give back to consumers the value of scarcity reflected in the energy market, in return for the capacity payments they receive. Where the CMU is available and providing energy to the system, they will earn the revenue needed from the energy market to “cover” the difference payments they must make under the RO. Where they are not available during these periods however, they are exposed to “uncovered” difference payments, which they must make without having earned the corresponding revenue from the energy market.

The operation of the RO thus creates an incentive for CMUs to be available during periods when the energy price reflects scarcity. The indicator of scarcity in this case is the energy price. However, price formation relies on the bidding behaviour of market participants, many of whom have CMUs subject to the RO and some of whom have multiple CMUs within a portfolio with varying degrees of availability. For CMUs subject to the RO, there is little incentive to bid above the RO strike price, as the additional revenue can only be retained in respect of any capacity above the level of the RO obligated capacity. Bidding above the RO strike price also runs the risk of exposing other units within a given portfolio to uncovered difference payments, especially in the event of unexpected plant failure.

ASP was designed into the SEM CRM as a means of helping to ensure that scarcity is reflected in the energy price, where this does not happen organically through the market. ASP is an administered price that supersedes the price calculated based on unit bidding where the available margin falls below a specified threshold, and where the value of ASP exceeds the price based on unit bidding. So while the RO itself is linked to the energy price as an indicator of scarcity, ASP is linked directly to the capacity margin.

However, ASP has not triggered in the SEM since it was implemented in 2018. As mentioned above, the operation of ASP has recently been examined by the SEM Committee, and a change made to the design of the trigger mechanism. As this has not yet been implemented however, the impact of the change is not certain.

Based on the operation of the RO, and of ASP, to date, the periods in which there has been an active incentive for CMUs to be available (i.e. when the RO has triggered) are characterised as shown in **Table 9**. The possibility that the RO *may* trigger also in principle creates a more “passive” incentive in other periods where market participants judge that the conditions may produce an RO event. However, the strength of this more passive incentive is debatable, given how little the RO has triggered in practise.

| Year | 2018 ³⁵ | 2019 | 2020 | 2021 ³⁶ | 2022 | 2023 | 2024 |
|-----------------------------|--------------------|-------|-------|--------------------|-------|------|-------|
| Duration of RO events / hrs | 2.5 | 2.0 | 1.0 | 18 | 2.5 | 0 | 4.5 |
| % of hours in the year | 0.1% | 0.02% | 0.01% | 0.21% | 0.03% | 0% | 0.05% |

Table 9: Occurrence of RO events per year.

If we consider from the perspective of consumers the question of how to determine the periods in which it is appropriate for availability incentives to apply to CMUs, we can also examine the approach to cost recovery. As considered further in Section 13, the CEEAG guidelines require that:

“The costs of a security of supply measure should be borne by the market participants who contribute to the need for the measure”.

The CISAF capacity market target model prescribes that:

“At least 90% of the capacity mechanism costs must be allocated to consumers based on their consumption during at least 1% and at most 5% of the highest price hours each year.”

The implicit assumption behind this requirement is that the periods of scarcity which determine the need for the capacity mechanism correspond to between 1% and 5% of hours in the year, and that price is a good proxy for the scarcity.

The range 1-5% is significantly higher than the share of hours in which the RO (whether triggered by the market, or by ASP) has triggered to date – this being in the range 0-0.21% of hours, with a median value of 0.03% of hours.

In designing a mechanism to supplement the RO, we consider that it would be appropriate to target that mechanism such that the relevant periods of system stress in which availability incentives apply correspond to 1-5% of hours in the year – the proportion of hours in which consumers are to be treated as contributing to the need for the Capacity Mechanism under the CISAF framework.

Given that the cost recovery is intended to reflect the hours in which there is the greatest need for the capacity measure, we propose that an indicator of scarcity for the targeting of availability incentives should be chosen such that the proportion of impacted periods would be similar. While the RO itself may account for some of this time, we propose that a supplementary measure should be applied for the remainder.

We have considered the approaches taken to incentivising availability in both Belgium and France as these countries have similar CRMs to the SEM, which have recently been implemented or granted State aid approval respectively.

³⁵ 2018 was a part year as the RO was only operational for Q4 of that year. This is why the % is relatively higher than for 2022 although the duration of RO events shown is the same.

³⁶ Part of the explanation for the increased incidence of RO events in 2021 may have been the rapidly rising gas prices at that time leading to the strike price lagging the marginal cost of gas plants.

Belgium

The Belgian CRM includes both an RO and a distinct availability obligation.

The availability obligation functions on the basis of an Availability Monitoring Trigger Price (AMT Price), set annually. The DAM price serves as the reference price. The AMT price represents the threshold above which there is considered to be an increased risk to adequacy and is defined based on modelling of the Belgian energy market. When the DAM price exceeds this threshold AMT Price, capacity market units are expected to be available.

The expected availability of energy-limited and non-energy-limited plant is calculated differently. For non-energy-limited plant, the capacity they must make available when the AMT Price is exceeded is equal to their contracted capacity. For energy-limited units, the maximum time that the unit must be available for, out of the total time that the AMT Price is exceeded in any one day, is equal to the run time of that unit. This maximum time is also constrained to run time that only requires one activation of the unit per day.

Where the AMT Price is exceeded, and the available capacity of a unit falls short of its obligated capacity, the "missing capacity" is subject to a financial penalty. The level of the penalty depends on:

1. The time of year, with missing capacity during winter subject to greater penalties than missing capacity during the summer; and
2. Whether prior notice of an outage has been given, with "unannounced missing capacity" subject to greater penalties than "announced missing capacity".

There is a yearly penalty cap applied, as well as a monthly cap, which is equal to 20% of the yearly cap. Under certain circumstances, where substantial missing capacity has occurred multiple times, the level of monthly capacity remuneration can be reduced.

France

The design of the new French mechanism was approved in Oct 2025. It includes an availability monitoring and penalty regime.

Certain peak period (PP) days are defined and communicated to the market, with at least a day's notice. During these PP days, the availability of capacity market units will be measured during a pre-defined timeframe. The intention is that there will be 15–25 PP days per capacity delivery period and that the timeframe for measuring availability will initially be 07:00-10:00 and 17:00-20:00. However, these are parameters that will be reviewed during the lifetime of the mechanism with the intention that they should be amended to reflect the evolving security of supply landscape.

The average available capacity of each capacity market unit is calculated during these PP days. A penalty is then applied in respect of any shortfall. The rate at which the penalty applies is specific to each unit, being a function of the price at which it is remunerated for its capacity.

Proposed Design

We view the RO as providing an availability incentive during extreme periods of system stress, with the potential financial exposure created for unavailable capacity

market units being very high (currently up to 25% VoLL minus the strike price), though subject to stop-loss limits.

The role of the supplementary availability monitoring and charging regime we are proposing is to establish an availability incentive for broader periods of system stress. Such periods will be associated with a lower level of risk to system security, and we consider that it is therefore appropriate for the incentive structure to create a lower level of financial risk to capacity providers.

Trigger

The trigger for the supplementary availability incentive could be based on the energy price. This would be clearly defined, transparent and in principle identify the correct periods of scarcity. This is the approach taken in the Belgian market. On the other hand, the RO strike price already links the operation of the CRM and that of the energy market, and creating an additional linkage could introduce unnecessary complexity and run the risk of influencing bidding behaviour.

An alternative is to base the trigger on a measure of margin, with a lower threshold set than in the case of the margin calculation for the purpose of ASP so as to capture the band of scarcity targeted. The RO would have primacy, in the sense that if the RO triggers in the same period as the supplementary availability incentive, then the supplementary incentive would not apply. The TSOs could give notice of imminent periods of expected scarcity that would breach the margin threshold.

Charging structure

For any CMUs unavailable during periods when the supplementary availability incentive is triggered, a charge would apply. This could be calculated as a % of each unit's monthly CRM payment, subject to stop-loss limits. It would also be possible for an additional incentive to be created by providing additional compensation to units available above the level of their awarded capacity.

11.2.2 Unit-specific DRFs

The concept of unit-specific DRFs is dealt with separately in Section 12, but we note it here because of the availability incentive that unit-specific DRFs would create. While the supplementary availability incentive described in this section could co-exist with a unit-specific DRF methodology, it would be important to consider whether unavailability was being double-counted through both charges for non-availability and being factored into the setting of a unit-specific DRF.

11.3 Recommendations

We propose that the availability incentives for CMUs in the SEM be strengthened through the establishment of a supplementary mechanism to the RO. This would be targeted at the tightest margin periods not covered by the RO, and associated with a lower financial exposure for CMUs than the RO.

The trigger would either be the price in the energy market, set at a lower level than the RO strike price, or a measure of margin, set at a lower threshold than in the case of ASP.

Aligned with the CISAF approach to identifying the customers contributing to the need for the CRM (i.e. those consuming during the 1-5% of highest priced hours),

we consider that the trigger threshold should be set to target this proportion of hours.

Finally, we highlight the interaction between this proposed mechanism and the unit-specific DRF methodology described in Section 12, and the importance of ensuring that the two are in alignment with one another.

12 Design: Derating Factors

12.1 Suitability for non-fossil flexibility

Modelling tool

In traditional electricity systems, capacity Derating Factors (DRFs) were calculated in order to reflect the non-availability of dispatchable units as a result of planned and forced outages, as well as the influence of unit size. As we transition towards a net zero system, non-fossil flexibility, such as demand response and storage, will have a key role to play in meeting adequacy needs as well as flexibility needs. The contribution of these resources to adequacy is determined not only by unit outages and size, but also by limitations on their running due to the fact that DSUs have a finite shutdown time and storage has a finite duration.

These limitations on the “energy” that DSUs and storage can provide to the system mean that the calculation of DRFs for these types of units has more dimensions to it than in the case of conventional units. This is also because, in order for these types of flexibility to support the system at certain times, they must add to demand at other times e.g. storage units need to charge, and some DSUs may need to shift their demand. An extra MW of storage for example may decrease the LoLP in one period, while increasing it in another, and the overall contribution of that unit to adequacy will reflect the net effect on the LoLP over all periods. We understand that the ISAC tool currently used by the TSOs for calculating DRFs is to be replaced by a more advanced tool, which will, in particular, be better able to capture the adequacy impact of energy-limited units, such as storage and demand response.

Unit-specific DRFs

In addition to the new tool, the SEM Committee is currently investigating the impact of a potential move towards unit-specific DRFs. We have examined the outturn availability data for the 2024/25 Capacity Year to assess the extent to which the DRF technology classes are available at the level of their awarded capacity across the year, and during scarce periods (defined here as the 5% of highest price periods), Figure 27 and Figure 28. As explained above, the contribution to adequacy of energy-limited units such as demand response and storage is not only a function of their availability, so an average availability that exceeds the awarded capacity (as is the case for “Other Storage”) does not necessarily indicate that the DRF is too low.

However, from the point of view of unit-specific DRFs it is instructive to examine the spread of availability across a given technology class. The error bars in Figure 27 and Figure 28 represent the spread of the data set for each technology, from the minimum to the maximum value. On an annual average basis, the range of availability of DSUs and Other Storage relative to their awarded capacity is considerable, and higher than that of the thermal units. This spread is similar when we examine only the periods with the highest 5% of prices, as a proxy for the periods with tightest capacity margin. On this basis, we consider that a move to unit-specific DRFs would be appropriate in the context of non-fossil flexibility in particular, though the spread in availability for conventional units could also justify such a move. This makes sense intuitively in the case of DSUs in particular, as there is greater variance in the characteristics of this technology class – depending as they do on the IDS composition of the unit – than is typically the case for other classes.

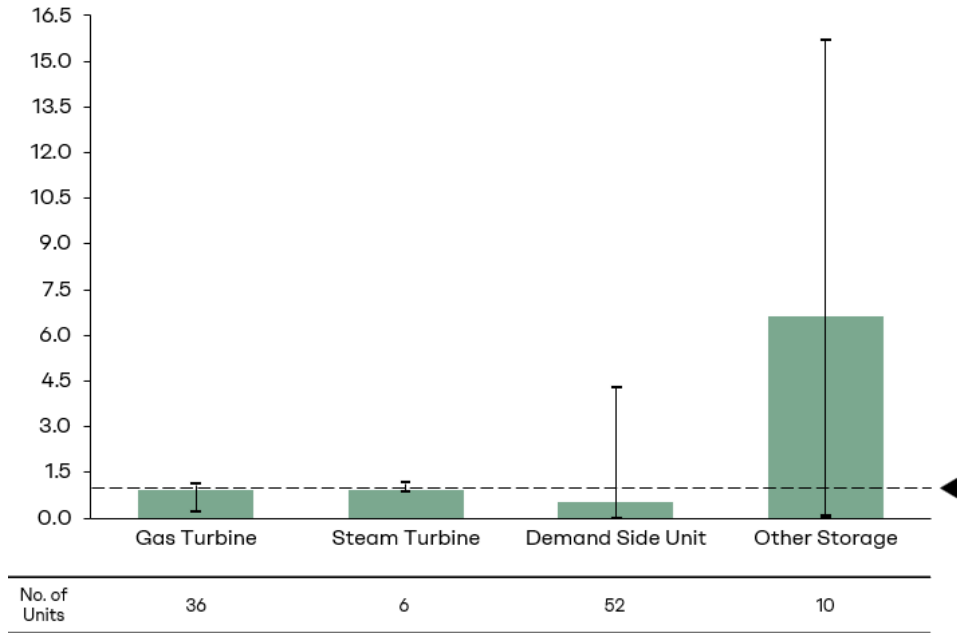


Figure 27: Average annual availability relative to awarded capacity for the 2024/25 Capacity Year. Error bars represent the min and max values. Dashed line is at a value of 1, where the average availability corresponds to the awarded capacity.

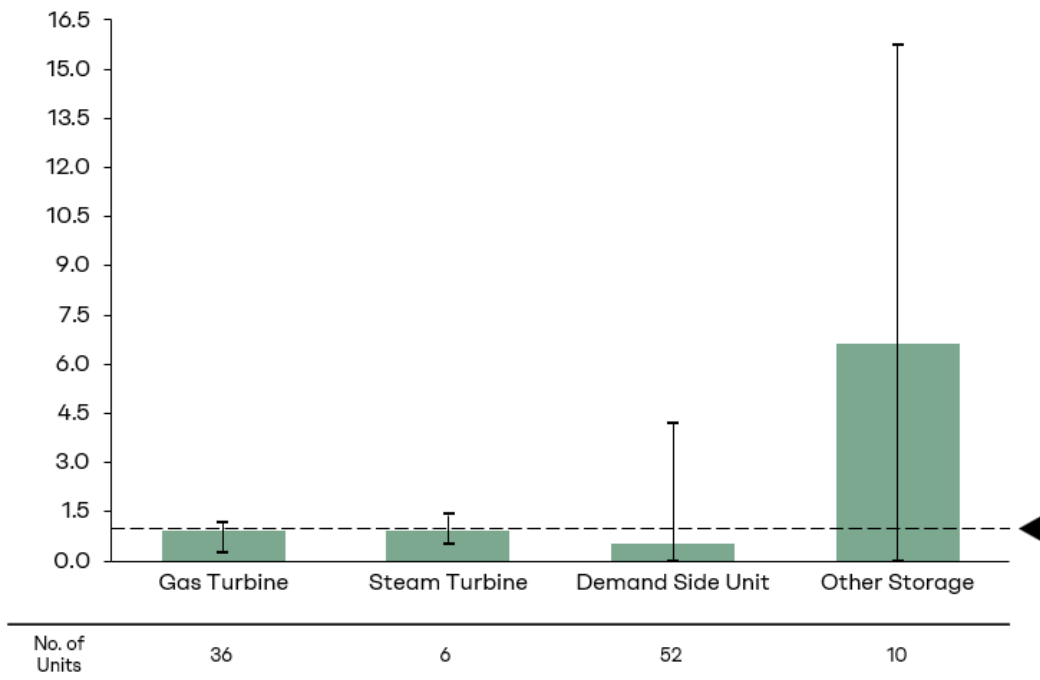


Figure 28: Average availability over the 5% highest price periods relative to awarded capacity for the 2024/25 Capacity Year. Error bars represent the min and max values. Dashed line is at a value of 1, where the average availability corresponds to the awarded capacity.

We also highlight the interaction between unit-specific DRFs and the enhanced availability incentives discussed in Section 11. This is due to the fact that unit-specific DRFs in themselves create an incentive for each individual unit to maximise its availability. This incentive is much stronger where DRFs are calculated on a unit-basis than on a technology class average basis. It may be possible to split out a unit-specific DRF into the component linked to the composition of the wider system and common to all units within a technology class, and a unit-specific multiplier reflecting the actual performance of each individual unit. This could allow for the availability incentive to apply even within a multiyear contract as the DRF could be fixed at the time of contract award, while the unit-specific multiplier would vary year on year through the contract term depending on the performance of the unit.

The CISAF requirement in respect of DRFs includes the following:

“Individual capacity providers are allowed to deviate from the default de-rating factor for the technology at issue (up to at least 15% of the standard de-rating factor of that technology). In this case, capacity providers must face the risk of penalties related to their custom de-rating factor.”

While, as mentioned previously, the CISAF requirements are not necessarily hard constraints, it is useful to note that a unit-specific derating methodology would appear to be in line with this element of the framework.

CISAF additionally requires that:

“All parameters calculated to assess availability, such as any de-rating factors, must be in line with the ERAA assumptions and results... The de-rating factors used should be those published by ACER/ENTSO-E as an output of the European Resource Adequacy Assessment for the relevant bidding zone, once available.”

We note however that there is the possibility to opt out of the calculation of DRFs via the ERAA, on the basis of justified national differences to the common ERAA methodology.

12.2 Key elements of unit-specific DRF design

In collaboration with the TSOs, we have considered at a high level the key policy elements of the design of a unit-specific DRF methodology. These are:

Should the unit-specific methodology apply to all technologies?

From the analysis presented in Figures 27 and 28, it is clear that there is greater variation in availability within some technology classes than others, and that there is perhaps on this basis a stronger case for moving to unit-specific DRFs for these technology classes. However, there is variation across all technology classes, and the incentive effect created by a unit-specific methodology would be beneficial even to those technology classes where the range of performance is narrowest.

Furthermore, applying the same methodology to all technologies would bring the benefit of consistency, while also maintaining equal treatment of all CRM participants. Finally, we note once more the CISAF requirement that individual capacity providers be permitted to deviate from the default DRF, which we interpret to be in reference to all providers and not specific technology classes.

Should the unit-specific DRFs be split into one component that is common to all units within a given technology class and a second component that is unit specific?

Instead of applying a single DRF to each unit, an alternative approach would be to apply both a technology class DRF and a unit-specific scalar.

The technology class DRF would capture the average adequacy contribution of a given type of technology, while the unit-specific scalar would reflect the individual performance of each unit. For new units, the unit-specific scalar could be set to 1, with each year of actual performance data fed into the scalar on a weighted basis.

We can see 2 principal benefits to this approach. Firstly, it would provide greater transparency, as variation in DRF values from one year to another could be more clearly attributed to either the evolving dynamics of the wider system or to the performance of the individual unit. This would be valuable in the case of energy-limited units in particular, for which the DRF is more dependent on the wider system than non-energy-limited units. The second benefit we identify relates to the case of multi-year contracts, where the DRF is fixed at the time of contract award. If the performance element was a separate scalar, then this could vary over the course of the contract term to reflect the actual performance of the unit and thereby allow the performance incentive to apply throughout.

How should availability be calculated on a unit basis?

There are different components to this:

- What should the timeframe of the historical data used to assess availability be e.g. the previous 5 years?
- How would this apply to new units for which there is no historical data available? This could be addressed by applying a technology class average for the first year, with each year of actual performance data then being fed into the DRF calculation on a weighted basis.
- Should availability over the full year be considered, or only during certain defined periods of scarcity?

These questions will need to be considered further as the work on the unit-specific DRF methodology and the new DRF tool progresses.

12.3 Recommendations

We consider that a unit-specific DRF methodology applied to all technology types would have benefits in terms of the availability incentive it creates, as well as being in line with the EU's CISAF target model for market wide Capacity Mechanisms. We also consider that this type of methodology is particularly appropriate for non-fossil flexibility because the variation in availability across units in a given technology class is greatest in the case of demand response and storage. We reiterate however that this approach would interact with the supplementary availability incentive described in Section 11. While these mechanisms could co-exist, it would be important to consider whether unavailability was being double-counted through both charges for non-availability and being factored into the setting of a unit-specific DRF.

The impact of a move to a unit-specific methodology would need to be assessed in detail in terms of both DRF values and the capacity requirement, and we understand that preliminary work on this is underway currently. We also understand however that the methodology cannot be fully optimised, tested or implemented until the TSOs' new tool for calculating DRFs has been developed.

Both the key elements of the high-level design of this methodology discussed above, and the detailed design, will need to be considered further as the initial impact assessment and the new DRF tool are developed. We suggest that a dedicated

consultation may be appropriate, allowing this element of the CRM Development Programme to progress to a separate timeline to the other elements.

Finally, we observe that the full detail of the DRF methodology (e.g. the detail of how the availability of each unit is calculated) may not need to be fully bottomed out for the State aid application or approval, though it would need to be in place for the commencement of the first auction cycle.

13 Design: Cost Recovery Mechanism

The EU framework for Capacity Mechanisms embeds the principle that the costs of these mechanisms should be borne by the consumers driving the need for them. This means that capacity charges should be levied at times when the system is scarce and the LoLP is highest. The CISAF framework requires specifically that:

"At least 90% of the capacity mechanism costs must be allocated to consumers based on their consumption during at least 1% and at most 5% of the highest price hours (or market time units) each year (or each delivery window)..."

The economic rationale for this is that targeting these costs at these periods will lead consumers to reduce or shift their demand to lower cost periods, thereby reducing the total amount of capacity required on the system and the associated cost of supporting it through the capacity mechanism.

In view of the critical role of active customers in the future decarbonised energy system, there is also a consumer empowerment element to the cost recovery mechanism. The more cost that is fixed, or fixed for large portions of the day, the less consumers are empowered to minimise their own costs and to support the system by doing so.

However, granular charging will only be effective in empowering consumers and producing demand response to the extent that consumers can "see" and understand the varying charge, and that their consumption can be metered and settled with matching granularity. Moving to a charging window of 1% of hours in the year would ideally require smart metering to be in place across the SEM, as standard or day/night meters will not capture consumption with the requisite resolution at the level of the individual consumer. This move would also require the retail offerings available to consumers to transmit the incentive created by the Supplier Capacity Charge. This latter requirement could be expected to be addressed by suppliers³⁷. The roll-out of smart meters is well advanced in Ireland, and A Design Plan for the Roll-out of Smart Meters³⁸ in Northern Ireland has recently been published. However, the full roll out of smart meters will take time to complete, with the first installations in Northern Ireland expected to take place in early 2028 and the installation programme expected to last up to 3 years.

13.1 Overview of approaches in other countries

The examples of approaches to targeted capacity cost recovery taken elsewhere, given in Table 10, illustrate different ways in which the capacity cost can be used to drive demand response during tight periods.

³⁷ Where wholesale settlement in the SEM reflects consumption with sufficient granularity.

³⁸ <https://www.economy-ni.gov.uk/publications/design-plan-roll-out-smart-electricity-meters>

| Country | Approach |
|---------------|---|
| France | <p>EDF in France offer a "tempo" tariff, which applies significantly higher rates during a limited number of "red days" – these being the 22 days of highest system stress.</p> <p>A 'red day' rate exceeds €200 per MWh and applies to consumption over 16 hours (totalling 352 hours (~4%) annually).</p> <p>There are 300 'blue days' during which the tariff is low, and 43 'white days' during which the tariff is slightly higher than on the blue days.</p> <p>From 11 o'clock on a given day, consumers can check the 'colour' of the following day to understand whether they need to plan to reduce their consumption or not.</p> |
| Italy | <p>A 'short-peak' charge is applied, which is 37 times higher than the off-peak charge.</p> <p>It applies to consumption during the 500 hours in a year (~6%) with the lowest surplus of supply over demand.</p> <p>Importantly, consumers in Italy are informed in advance about peak hours for the upcoming year.</p> |
| Poland | <p>Currently, household, and other small customers, pay a flat rate levy.</p> <p>All other customers are charged the capacity levy at a rate that depends on the difference between their consumption during peak demand hours and the remaining hours of the day.</p> <p>The flatter the demand profile, the lower the Capacity Levy that these customers pay.</p> <p>From 2028, this approach to the application of the Capacity Levy will be extended to all customers, including households.</p> |

Table 10: Examples of approaches to targeted capacity cost recovery in other countries.

13.2 Impact on charge rate

The costs of the CRM are recovered through the Supplier Capacity Charge, which currently applies at a flat per MWh rate from 07:00–23:00 on weekdays. This corresponds to approximately 48% of the hours in the year.

We have assessed the impact of concentrating the capacity cost recovery in the SEM wholly into a smaller number of hours³⁹. For the 2024/25 Capacity Year, the total capacity cost was €603 million⁴⁰. The per MWh Supplier Capacity Charge Price is shown in Table 11 for a number of different scenarios, compared with the status quo. While the price varies by scenario, the same total cost is recovered in all scenarios.

| Scenario | Supplier Capacity Charge Price (€ / MWh) |
|-----------------------------|--|
| Status quo (48% of hours) | 26.25 ⁴¹ |
| 25% of highest priced hours | 49.60 |
| 5% of highest priced hours | 227.31 |
| 1% of highest priced hours | 1059.68 |

Table 11: Supplier Capacity Charge in different cost recovery scenarios

However, the distribution of this total cost will vary depending on the consumption pattern of different consumer types. Those customers that consume more during the higher priced hours will also be subject to higher capacity costs. In this sense, the capacity price would reinforce the signal from the energy price. The objective would be for this to lead to a reduction in demand during the highest priced hours and a reduced need for capacity as a result. If we make the simplified assumption that a 1% reduction in demand during the highest priced hours translates into a 1% reduction in the capacity requirement, then this would indicatively represent a €6 million saving for consumers based on the capacity cost for the 2024/25 capacity year.

13.3 Recommendations

We consider that a more targeted cost recovery window than is currently in place would be beneficial from an economic perspective, as well as being more forward-looking in terms of encouraging consumers to engage with their electricity consumption. It is also likely to be an important aspect of the State aid application and an area of focus for the European Commission.

We propose two alternative options. Firstly, the costs could be targeted at the upper end of the range specified in CISAF i.e. at 5% of the highest priced periods. Alternatively, in light of the current status of the smart metering roll-out across the SEM, a glide path could be followed, beginning with a move to 25% of the highest priced hours. These could be set as 8 hours per day Mon-Fri, spread over the morning and evening peaks. Once smart metering is more fully rolled out, the cost recovery window would be narrowed further in line with the CISAF requirement.

Finally, we note also the possibility of applying different charge rates to different consumer categories e.g. Domestic and Non-Domestic of different sizes.

³⁹ In this case we have concentrated 100% of the costs into the specified hours.

⁴⁰ https://www.semcommittee.com/files/semcommittee/2024-09/SEM-24-056%20SEM%20Tariffs%20and%20Charges%20for%20TY2024-25_0.pdf

⁴¹ Note that this differs from the published 2024/25 tariff due to the use of slightly different demand datasets. The same dataset was used for all scenarios in Table 11, so the figures in this table are internally consistent.

14 Design: Flexibility Integration

14.1 Context

The question of how to integrate flexibility procurement with capacity procurement is a **forward-looking** one. It is also a key area of the design that must be addressed for State aid purposes.

The Flexibility Needs Assessments (FNA's) are currently in development in Ireland and Northern Ireland, with the expectation that the first iterations will be published in Q3 2026^{42,43}. These will serve, amongst other things, to inform the setting of national objectives for non-fossil flexibility and to signal priority areas for investment.

EU legislation provides for the establishment of Non-Fossil Flexibility Support Schemes for new capacity, aligned with the needs identified through the FNA. In time, and in principle, it is therefore possible that such schemes could be established at a national level. And while the FNAs are currently carried out on a jurisdictional basis, our view is that procurement of new investment on an all-island basis could become the optimal approach for certain "system-level" flexibility needs in the future. However, the development of flexibility procurement is at a relatively early stage at this point, so it is not yet known how exactly it will be achieved.

In this context, and in line with the design philosophy set out in our Review of taking a "dynamic approach to State aid approval", our proposal is to design CRM 2.0 so as to accommodate the potential ways in which flexibility procurement may play out across Northern Ireland, Ireland and the SEM. Our aim is to future-proof the high-level design without constraining it to a specific detailed design that may or may not be appropriate in future, depending on how the approach to flexibility procurement develops. Specifically, we propose accommodating 2 approaches prescribed in the CISAF framework as follows:

1. "Resources must choose between **participating in only one measure**, either the non-fossil flexibility support scheme or the capacity mechanism. The target demand in each measure should be adjusted to take account of participation in the other measure"; and
2. "MSs may **include non-fossil flexibility requirements** identified in the flexibility needs assessment (in line with Article 19e(2)(c) of the Electricity Regulation) in their capacity mechanisms, for example requiring a minimum volume of non-fossil flexible capacity providing short term ramping services".

14.2 Participation in only one measure

In the case where one or more jurisdictional NFFSS's are implemented during the lifetime of CRM 2.0, CISAF requires participation to be limited to either the NFFSS or the Capacity Mechanism. As previously mentioned, the CISAF requirements are not hard obligations, but have been set out as a "target model" for capacity market design and are therefore useful as an indication of the EC's thinking.

⁴² [Northern Ireland's First Flexibility Needs Assessment Information Paper.pdf](#)

⁴³ [Flexibility Needs Assessment | CRU.ie](#)

The rationale that we see for this is that allowing dual participation creates the risk of both overcompensation of the beneficiaries and of projects failing to deliver. If we take the case where a unit is awarded a long-term contract in a NFFSS procurement that takes place in advance of a CRM auction, the scenarios shown in **Table 12** could result. And while it is possible that a project will deliver in an efficient way (Scenarios 2 and 3) when dual participation is allowed, there is also a reasonable likelihood that it will be overcompensated (Scenario 1) or terminated (Scenario 4).

| Scenario | Bid assumption in NFFSS | Result of CRM auction | Consequence |
|----------|--|-----------------------|--|
| 1. | Failure in CRM auction – NFFSS revenue sufficient for project viability | Project succeeds | Project delivers, with overcompensation – CRM revenue represents a windfall |
| 2. | | Project fails | Project delivers |
| 3. | Success in CRM auction – NFFSS revenue alone insufficient for project viability | Project succeeds | Project delivers |
| 4. | | Project fails | Project termination – Shortfall in flexibility procured |

Table 12: Scenarios that may arise where participation in a NFFSS and a CRM is possible.

As a general principle, it is not efficient for an investment to rely on success in multiple uncoordinated long-term contract procurements because of these risks. However, it is worth noting that revenue stacking between a single long-term contract and the spot markets is a different prospect because:

1. It is beneficial for the recipient to be exposed to the operational signals from the spot markets (including ancillary services); and
2. Certainty on spot market revenue is not essential/possible in advance of a Final Investment Decision and so should not have a binary impact on commercial decision-making.

Even in the case of multiple long-term contract procurements, there are some nuances to the argument that mutual exclusivity is the optimal approach. The general expectation is that where services are complementary, operators of resources can stack services and revenues, and for services that are mutually exclusive, the operator may choose which services to offer (within the constraints of any existing contracts).

The contracting framework should not unduly constrain the operation of the asset e.g. if it holds a capacity contract, it should not generally be excluded from offering (complementary) services. Indeed, it is beneficial from a system perspective for the asset to be incentivised to provide the range of services that it can provide and that the system needs.

In addition, there may be ways of mitigating the risk of overcompensation that arise from allowing dual participation. For example, dual participation could be permitted where beneficial, but with the revenue from the second auction clawed back from the participant. This could work for example where the objective was for an asset

supported under a NFFSS to be exposed to the contractual availability obligation framework under the CRM.

Finally, preventing dual participation may effectively lead to cross-subsidisation as the costs of the capacity contribution of “flexibility” procured through a NFFSS are recovered from the consumers of the flexibility service rather than the capacity “service”. The cost is not correctly attributed. This would matter more or less depending on the mechanism for cost recovery and the complementary mechanisms to incentivise availability of the capacity and flexibility services at times when the services are actually needed.

Our proposal therefore is that if one or more jurisdictional NFFSS’s⁴⁴ are implemented during the lifetime of CRM 2.0, then successful participants in those schemes should not in general be allowed to participate in the CRM. The capacity contribution of the flexible resources procured via a NFFSS should be taken into account in setting the capacity requirement for the CRM auctions i.e. the capacity requirement should be reduced to reflect the contribution of the flexible resources. This is in line with the relevant approach described in CISAF. However, some flexibility should be retained to consider the approach on a case-by-case basis as there could be circumstances, depending on the nature of the NFFSS, where it made sense to allow dual participation (e.g. where the services are complementary, or where it made for a fairer cost allocation) and the risk of overcompensation and project termination could be mitigated (e.g. through a claw-back mechanism). As the exact nature of any future NFFSS is not known at this time, it is important to keep this option open.

14.3 Flexibility requirements included in CRM 2.0

The approach to flexibility integration described in Section 14.2 deals with the case where jurisdictional flexibility support schemes are established. Alongside this, we consider now the case where certain aligned needs are identified in Northern Ireland and Ireland, and decisions are taken to secure new investment to meet these needs on an all-island basis. In this case, the second CISAF approach described above, could be implemented. This approach is to include non-fossil flexibility requirements in the CRM, by for example requiring a minimum volume of non-fossil flexible capacity providing specified flexibility services.

In this context, we have examined the recent State aid decision on the French Capacity Mechanism – this decision having been issued since the Electricity Market Reform introduced the concepts of the FNA and NFFSS. The intention is for the French Capacity Mechanism to be used to satisfy the national objective for non-fossil flexibility. If the flexibility needs identified have not been satisfied at T-4, then a constraint will be applied to the T-1 auction to ensure that the remaining required volume of non-fossil flexibility is procured at that stage. They will define a quantity, V_{flex} , corresponding to the volume of non-fossil flexibility needed to meet the indicative national objective, net of the volume of non-fossil flexibility already contracted at T-4. If V_{flex} is secured at the T-1 stage without the application of the constraint, then all capacity is remunerated at the clearing price of the auction. If however, the constraint binds, then all non-fossil flexible capacity will be remunerated at the price of the last unit of capacity required to meet V_{flex} , while the

⁴⁴ Assuming these to award long-term contracts to investors in new flexibility resources.

other technologies will be remunerated at the clearing price of the unconstrained auction.

This approach is similar in some respects to the way in which the locational capacity constraints operate in the current SEM CRM (though the capacity procured as a result of the application of the locational constraints in the SEM is paid as bid).

We propose that provision be made in the design of CRM 2.0 for the application of a similar constraint to the auctions in future, in the case where flexibility needs have been identified on an all-island basis that must be met through new investment. Given that the timeframe for the development of non-fossil flexibility in the form of DSUs and storage is typically shorter than that of thermal generation, we consider it appropriate that the constraint should be applied in the top up auction only, rather than in the main auction.

However, given the uncertainty at this point as to how the identification of flexibility needs may play out on an all-island basis, we believe that it would be best to avoid being overly prescriptive in the State aid application so as to allow the granular design to be optimised if and when the details of the kind of flexibility to be procured through the CRM become known.

14.4 Recommendations

As a means of future-proofing CRM 2.0 for potential developments in the framework for procurement of non-fossil flexibility, we recommend including the following two provisions in the State aid application:

1. Where a separate NFFSS is established in future, capacity contracted under that NFFSS will in general not be allowed to participate in CRM 2.0. The capacity requirement in the CRM auctions will be adjusted to reflect the capacity contribution of the flexible resources procured through the NFFSS. However, some flexibility should be retained to consider the approach on a case-by-case basis as there could be circumstances, depending on the nature of the NFFSS, where it may make sense to allow dual participation, provided the risks of overcompensation and project termination are avoided.
2. Where non-fossil flexibility needs are identified on an all-island basis that require new investment not incentivised through a dedicated NFFSS, a constraint can be applied to the CRM auctions to ensure that the capacity procured also satisfies those flexibility needs.

For completeness, we also address the third and final approach proposed in CISAF to the integration of flexibility and capacity procurement. This is a fully co-optimised procurement. While this would represent an efficient approach to the procurement of the two products, we do not consider it feasible to develop or provide for within the timeframe of the next State aid application. As explained in further detail in our Review, we have therefore placed this option in the pot of changes that could be considered over the lifetime of CRM 2.0 and that would likely require re-engagement with the State aid authorities.

Finally, we reiterate the idea of taking a dynamic approach to State aid approval, which in this case we view as:

1. Making these provisions related to flexibility procurement as it may develop in the future;
2. Retaining the flexibility to allow dual participation where beneficial and the risks are appropriately mitigated; and

3. Avoiding being overly prescriptive in how the non-fossil flexibility constraint would operate, given the lack of detail at this stage on the nature of the flexibility needs that may in future be identified on an all-island basis.

15 Design: Decarbonisation

15.1 Consultation responses

In our previous report “Options for Decarbonisation of the Existing SEM CRM Design”⁴⁵, we assessed decarbonisation options in the context of the existing CRM. The recommended options were consulted upon by the SEM Committee⁴⁶ and these, along with a response summary are published alongside this document. The broad preference of respondents was for the introduction of a Green Scalar, although it was noted by many that further detail would be required for full evaluation of the measure and that these changes would be better considered in the context of the next State aid application, given the limited remaining lifetime of the existing CRM.

15.2 Green Scalar

Informed by the consultation responses, we have considered further the concept of the Green Scalar from a longer-term perspective. There are different types of technology that could in principle benefit from such an incentive:

1. Fossil plants could be incentivised to improve their efficiency – however, we do not see that the Green Scalar would create a clear additional incentive effect for such plants, beyond the incentive created by the Intermediate Length Contracts available for refurbishing existing units, and the standalone commercial incentive to invest in higher efficiency thermal plant.
2. Non-fossil flexibility – however, there are separate mechanisms that we consider elsewhere to facilitate non-fossil flexibility⁴⁷ and there may ultimately be dedicated mechanisms for the procurement of non-fossil flexibility⁴⁸ pursuant to the Flexibility Needs Assessments that are in train currently. In addition, storage and DSUs are already competing, and winning, in CRM auctions. For both of these reasons, we consider that applying a Green Scalar to these units runs the risk of overcompensation.
3. Decarbonised dispatchable capacity (e.g. CCS/H₂/ammonia/biomethane) – while such plants are technologically viable, the policy framework, and in some cases, infrastructure, are not yet there for them to be deployed at scale. These plants would likely need broader support than the CRM i.e. in addition to being more costly in capex terms, these technologies are subject to an opex disadvantage relative to unabated natural gas for example. This implies that a separate support mechanism to the CRM would be required.

However, in line with the design philosophy set out in our Review, which includes taking a dynamic approach to State aid approval – allowing continued evolution of CRM 2.0 over its lifetime, including by “*building flexibility into the State aid approval where possible and useful*” – we consider that the Green Scalar could be included in the State aid application as a means of providing for future policy and technological

⁴⁵ <https://www.semcommittee.com/files/semcommittee/2025-12>

⁴⁶ [SEM-25-070 Consultation Decarbonisation of Existing CRM.pdf](#)

⁴⁷ Keeping the optimal timeframe of the auctions for non-fossil flexibility under review (Section 10) and adapting the DRF tool and methodology to better fit the characteristics of energy-limited plant (Section 12)

⁴⁸ Be these jurisdictional support schemes, or through the CRM (Section 14).

development. The idea would be that State aid approval would permit the use of the Green Scalar, but that it would not be deployed until such time as it was clear that the conditions across the wider energy ecosystem were correct i.e. that the CRM could provide the critical “missing money” for relevant technologies which would otherwise be disadvantaged absent the Green Scalar. The SEM Committee would review on a regular basis (for example, annually) whether it was appropriate to deploy the Green Scalar, based on the latest technological and policy developments.

In this sense, the Green Scalar is similar to the approach to Flexibility Integration described in the previous chapter, in that it is a means of future-proofing the design of CRM 2.0 by setting out at a high level how the mechanism would operate, without constraining it to specific low carbon technologies that may or may not become viable in the future.

Hypothetical example

The idea of the Green Scalar is that it would help to level the playing field between low carbon technologies and higher-carbon technologies, by assigning a value to the “low carbon” nature of the capacity.

Carbon pricing already serves as a relative disincentive to the development of higher-carbon capacity, but where there is a greater gap to be bridged to enable low-carbon capacity to be competitive, the Green Scalar could be used.

The relative Capex, and fixed Opex, costs for developing a number of low carbon technology types, compared with the costs of developing natural gas plant in the SEM are shown in Figure 29 and Figure 30 respectively. These are taken from AFRY’s technology cost database. It can be seen that based on current projections, a hydrogen or CCS plant is at a relative disadvantage in Capex terms compared to a gas plant, be that GT or CCGT. In terms of fixed Opex, CCS plant is also projected to be at a significant disadvantage relative to non-CCS plant. The fixed Opex costs of hydrogen plants are similar to those of gas plant, but the substantially higher price of hydrogen over natural gas, Figure 31, means that the variable Opex costs will be considerably higher. Currently therefore, both of these low carbon technologies would need operational support as well as support through the Capacity Mechanism.

We can imagine the case of a hypothetical dispatchable low-carbon technology, which is in the future supported by policy in both jurisdictions within the SEM and which is no longer at an Opex disadvantage relative to unabated natural gas. It is, in effect, the “low-carbon Best New Entrant”. It is not competitive in the CRM because its capex costs are (say) 20% higher than the overall Best New Entrant technology (notwithstanding the application of a multiplier to Net Cost in the calculation of the Auction Price Cap). The Green Scalar could be used to offset this difference by allowing the unit to bid in at a price that takes into account the subsequent application of the multiplier.

The Green Scalar would be applied as follows:

$$CPP_{act} = \text{Max}(CPP_{orig}, GS.BP)$$

| | | |
|--------------|---|--|
| CPP_{act} | = | Actual Capacity Payment Price to be paid out |
| CPP_{orig} | = | Original Capacity Payment Price based on the auction outcome |
| GS | = | Green Scalar value |
| BP | = | Bid Price of the low carbon capacity unit |

This means that the Green Scalar would only impact the actual Capacity Payment Price paid out to the unit where the clearing price of the auction was not sufficient, in effect, to allow the low carbon capacity to recover its costs. In this case, the Green Scalar would be applied to the original bid price of the unit to determine the actual Capacity Payment Price. The application of the Green Scalar would not impact the overall clearing price, nor the Capacity Payment Price paid to other units.

In SEM-25-070, the options of setting the Green Scalar as either a continuous or linear function were consulted on. Here, we take the simple case of a single step function, where the value would be set to 1 for all non-eligible capacity. For eligible capacity, the value of the Green Scalar would be set so as to reflect the additional Capex cost associated with the development of the "low carbon BNE" technology, which for the purpose of this example, is 20%. The Green Scalar would therefore be set at 1.2, to allow cost recovery from the CRM on an equal footing with higher-carbon capacity.

Eligibility for the application of the Green Scalar would be determined on the basis of 2 criteria:

1. The specific emissions of the unit should be zero (or very close to zero) i.e. in the terminology of the Electricity Regulation, it should emit no more than 0 g of CO₂ of fossil fuel origin per kWh; and
2. The value that the unit brings in terms of avoided carbon emissions on a per MW basis should exceed the additional Capex cost associated with that unit on a per MW basis. This value would be calculated on the basis of the modelled avoided emissions and the forecast carbon price.

This second criterion is intended to take into account the system-wide impact of low carbon capacity and to avoid a theoretical situation where a low carbon plant benefiting from the Green Scalar never or almost never runs in the market and therefore brings no benefit in environmental terms because it doesn't actually displace higher carbon capacity in practise.

15.3 Recommendations

As a means of future-proofing the design of CRM 2.0, we propose that provision be made in the State aid application for the introduction of a Green Scalar if the technology, infrastructure and policy context evolve such that the scalar would materially incentivise the development of low carbon technologies.

The Green Scalar would be set so as to reflect the additional Capex costs associated with a low carbon Best New Entrant technology. It would only impact the price paid to the eligible low carbon technology and not that paid to other capacity, and it would only do this where the clearing price of the auction was less than the bid price of the technology concerned multiplied by the Green Scalar.

Technologies would be eligible for the Green Scalar where their specific emissions were zero (or very close to zero), and where the value of the carbon emissions they would displace on the system exceeded the additional cost of support through the CRM.

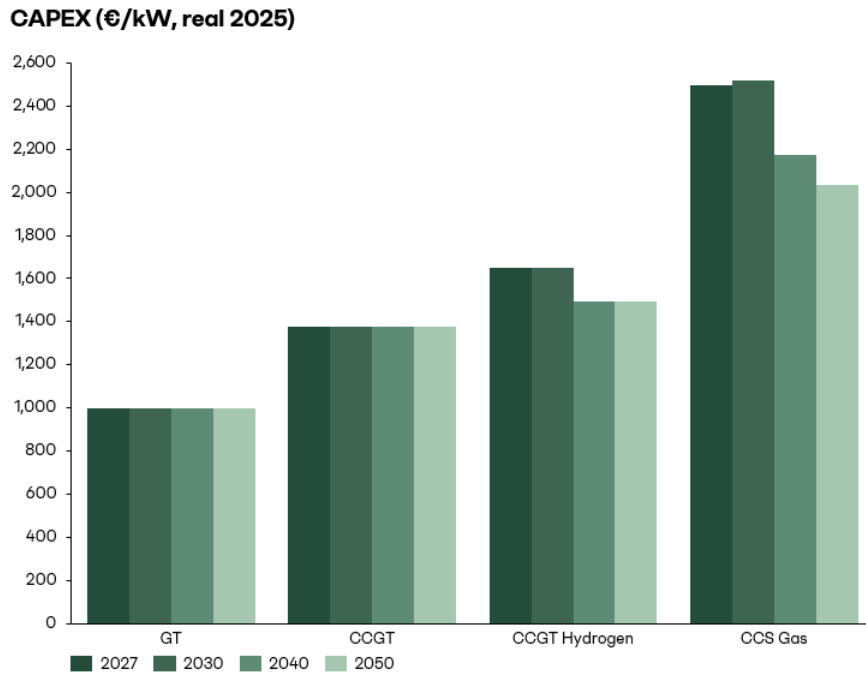


Figure 29: AFRY projections of Capex costs for natural gas plants (GT and CCGT) compared with the example low carbon technologies, hydrogen CCGT and natural gas with CCS.

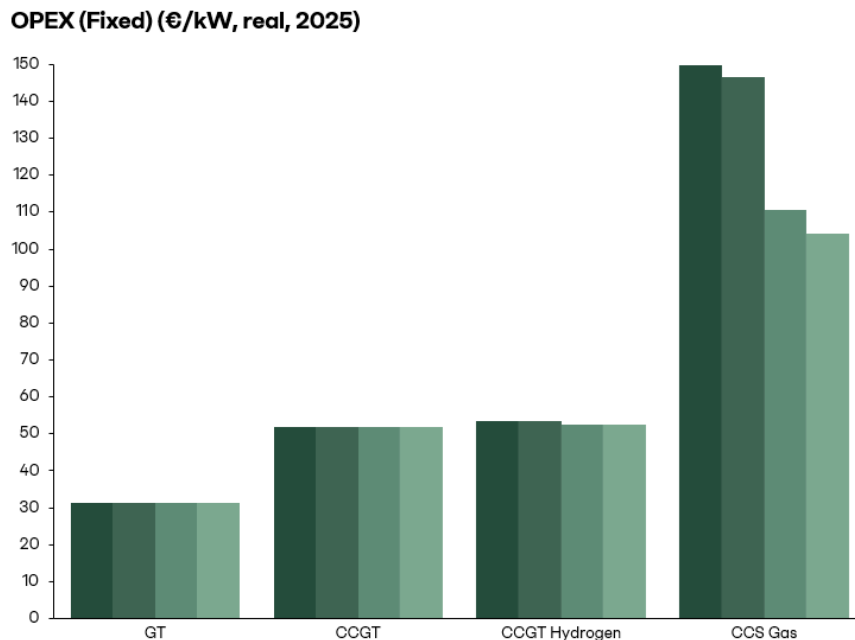


Figure 30: AFRY projections of fixed Opex costs for natural gas plants (GT and CCGT) compared with the example low carbon technologies, hydrogen CCGT and natural gas with CCS.

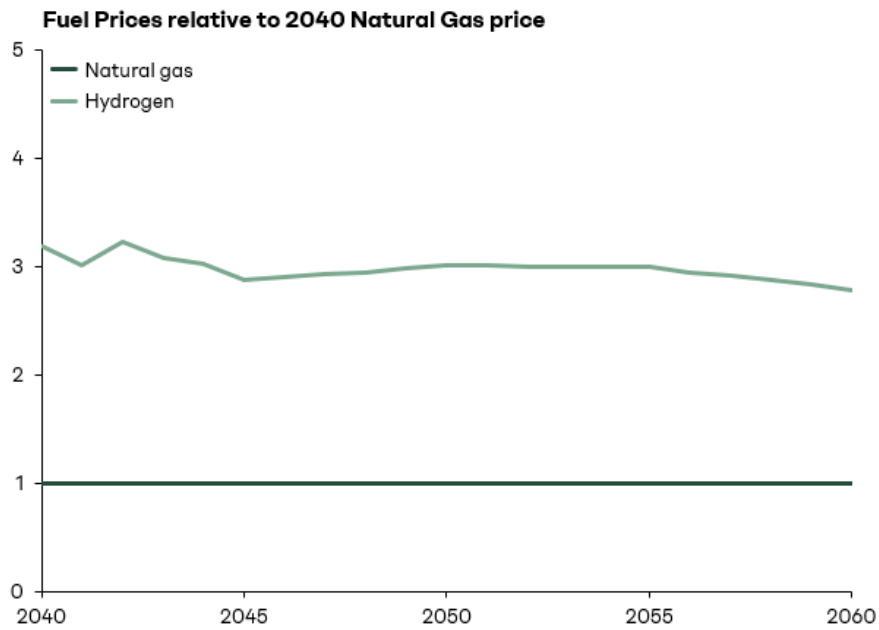


Figure 31: AFRY projections of natural gas and hydrogen prices across the SEM from 2040-2060, relative to the projected gas price in 2040 (i.e. prices for both fuels for all years have been divided by the 2040 natural gas price).

Annex A Electricity Regulation: General principles for capacity mechanisms

1. To eliminate residual resource adequacy concerns, Member States may, as a last resort while implementing the measures referred to in Article 20(3) of this Regulation in accordance with Article 107, 108 and 109 of the TFEU, introduce capacity mechanisms.
2. Before introducing capacity mechanisms, the Member States concerned shall conduct a comprehensive study of the possible effects of such mechanisms on the neighbouring Member States by consulting at least its neighbouring Member States to which they have a direct network connection and the stakeholders of those Member States.
3. Member States shall assess whether a capacity mechanism in the form of strategic reserve is capable of addressing the resource adequacy concerns. Where this is not the case, Member States may implement a different type of capacity mechanism.
4. Member States shall not introduce capacity mechanisms where both the European resource adequacy assessment and the national resource adequacy assessment, or in the absence of a national resource adequacy assessment, the European resource adequacy assessment have not identified a resource adequacy concern.
5. Member States shall not introduce capacity mechanisms before the implementation plan as referred to in Article 20(3) has received an opinion by the Commission as referred to in Article 20(5).
6. Where a Member State applies a capacity mechanism, it shall review that capacity mechanism and shall ensure that no new contracts are concluded under that mechanism where both the European resource adequacy assessment and the national resource adequacy assessment, or in the absence of a national resource adequacy assessment, the European resource adequacy assessment have not identified a resource adequacy concern or the implementation plan as referred to in Article 20(3) has not received an opinion by the Commission as referred to in Article 20(5).
7. When designing capacity mechanisms Member States shall include a provision allowing for an efficient administrative phase-out of the capacity mechanism where no new contracts are concluded under paragraph 6 during three consecutive years.
8. Capacity mechanisms shall be temporary. They shall be approved by the Commission for no longer than 10 years. They shall be phased out or the amount of the committed capacities shall be reduced on the basis of the implementation plans referred to in Article 20. Member States shall continue to apply the implementation plan after the introduction of the capacity mechanism.

Annex B Electricity Regulation: Design principles for capacity mechanisms

1. Any capacity mechanism shall:

- (a) be temporary;
- (b) not create undue market distortions and not limit cross-zonal trade;
- (c) not go beyond what is necessary to address the adequacy concerns referred to in Article 20;
- (d) select capacity providers by means of a transparent, non-discriminatory and competitive process;
- (e) provide incentives for capacity providers to be available in times of expected system stress;
- (f) ensure that the remuneration is determined through the competitive process;
- (g) set out the technical conditions for the participation of capacity providers in advance of the selection process;
- (h) be open to participation of all resources that are capable of providing the required technical performance, including energy storage and demand side management;
- (i) apply appropriate penalties to capacity providers that are not available in times of system stress.

2. The design of strategic reserves shall meet the following requirements:

- (a) where a capacity mechanism has been designed as a strategic reserve, the resources thereof are to be dispatched only if the transmission system operators are likely to exhaust their balancing resources to establish an equilibrium between demand and supply;
- (b) during imbalance settlement periods where resources in the strategic reserve are dispatched, imbalances in the market are to be settled at least at the value of lost load or at a higher value than the intraday technical price limit as referred in Article 10(1), whichever is higher;
- (c) the output of the strategic reserve following dispatch is to be attributed to balance responsible parties through the imbalance settlement mechanism;
- (d) the resources taking part in the strategic reserve are not to receive remuneration from the wholesale electricity markets or from the balancing markets;

(e) the resources in the strategic reserve are to be held outside the market for at least the duration of the contractual period.

The requirement referred to in point (a) of the first subparagraph shall be without prejudice to the activation of resources before actual dispatch in order to respect the ramping constraints and operating requirements of the resources. The output of the strategic reserve during activation shall not be attributed to balance groups through wholesale markets and shall not change their imbalances.

3. In addition to the requirements laid down in paragraph 1, capacity mechanisms other than strategic reserves shall:

(a) be constructed so as to ensure that the price paid for availability automatically tends to zero when the level of capacity supplied is expected to be adequate to meet the level of capacity demanded;

(b) remunerate the participating resources only for their availability and ensure that the remuneration does not affect decisions of the capacity provider on whether or not to generate;

(c) ensure that capacity obligations are transferable between eligible capacity providers.

4. Capacity mechanisms shall incorporate the following requirements regarding CO emission limits:

(a) from 4 July 2019 at the latest, generation capacity that started commercial production on or after that date and that emits more than 550 g of CO₂ of fossil fuel origin per kWh of electricity shall not be committed or to receive payments or commitments for future payments under a capacity mechanism;

(b) from 1 July 2025 at the latest, generation capacity that started commercial production before 4 July 2019 and that emits more than 550 g of CO₂ of fossil fuel origin per kWh of electricity and more than 350 kg CO of fossil fuel origin on average per year per installed kWe shall not be committed or receive payments or commitments for future payments under a capacity mechanism.

The emission limit of 550 g CO₂ of fossil fuel origin per kWh of electricity and the limit of 350 kg CO of fossil fuel origin on average per year per installed kWe referred to in points (a) and (b) of the first subparagraph shall be calculated on the basis of the design efficiency of the generation unit meaning the net efficiency at nominal capacity under the relevant standards provided for by the International Organization for Standardization.

By 5 January 2020, ACER shall publish an opinion providing technical guidance related to the calculation of the values referred in the first subparagraph.

5. Member States that apply capacity mechanisms on 4 July 2019 shall adapt their mechanisms to comply with Chapter 4 without prejudice to commitments or contracts concluded by 31 December 2019.

Annex C CISA target models for capacity mechanisms

| Req. | Scope | Description |
|---|-----------|--|
| Necessity of aid, incentive effect and compatibility with Electricity Regulation Articles 20(1), 21(1), 21(4), 22(1.c), and 23 | | |
| 1 | SR, MW | a) the latest available European Resource Adequacy Assessment (ERAA)[1] central reference scenarios approved by the European Union Agency for the Cooperation of Energy Regulators (ACER) must be the basis for identifying the need for a capacity mechanism. The reliability standard, calculated as the ratio of cost of new entry (CONE) / value of lost load (VOLL)[2], must not be met in the Member State concerned at least as of the first delivery window (see criterion 18 below) within the approval period; and |
| | | b) all parameters calculated to assess availability, such as any de-rating factors, must be in line with the ERAA assumptions and results[3]. |
| Market failure and appropriateness of aid and compatibility with Electricity Regulation Articles 20(3-8) and 21(3) | | |
| 2 | SR, MW | Member State must have received an opinion from the European Commission after they submitted their market reform plan. If recommendations were made in the Commission opinion, the Member State must either have published an updated market reform plan for implementing all recommendations or commit to publishing such a plan within 3 months of the adoption of the State aid decision. |
| 3 | MW | Member State must confirm it has assessed whether a strategic reserve is capable of addressing the resource adequacy concern. |
| Eligibility and compatibility with Electricity Regulation Articles 22(1), 22(4) and 26 | | |
| 4 | SR, MW | In line with point (28), the capacity mechanism must not be open to undertakings in difficulty. In line with point (36), participation must not be conditional on relocation, and any outstanding recovery order will be taken into account in line with point (33). |
| 5 | SR, MW | The capacity mechanism must be open to all technologies, beneficiaries and projects that meet transparent, objective and non-discriminatory technical and environmental |

| | | |
|--|-----------|--|
| | | requirements. No other criteria are included. Minimum size required for participation must not be above 1 MW de-rated or above 1 hour of minimum delivery duration and must allow aggregation. |
| 6 | SR, MW | Beneficiaries must meet the Electricity Regulation CO ₂ emission limits. The Member State can apply more stringent CO ₂ limits, calculated in line with ACER methodology. |
| 7 | SR, MW | The Member State confirms that de-rating factors have been set in accordance with criterion 1. The multiplication of the relevant de-rating factor by the installed capacity of one unit provides the default capacity value (in MW) which is eligible to participate in the capacity mechanism. Individual capacity providers are allowed to deviate from the default de-rating factor for the technology at issue (up to at least 15% of the standard de-rating factor of that technology). In this case, capacity providers must face the risk of penalties related to their custom de-rating factor. |
| 8 | MW | The capacity mechanism must be open to cross-border participation in line with ACER methodology[4]. Maximum entry capacity must be set based on the ACER rules. |
| Proportionality of aid and compatibility with Electricity Regulation Articles 22(1) and 22(3) | | |
| 9 | SR, MW | The maximum[5] target demand to be auctioned should be calculated based on ERAA central reference scenario results so that the reliability standard, determined as described in criterion 1, is reached. A demand curve should be set so that demand is reduced proportionately if prices in the competitive bidding process exceed the CONE used to calculate the reliability standard. Bid caps can be introduced. If bid caps are used they must: <ul style="list-style-type: none"> - (a) be set at a level that avoids inefficient early closure of existing assets based on a detailed estimate of costs and revenues per reference project; and - (b) be accompanied by a process for individual resources to justify to the NRA an exception from the price cap based on their specific costs. |
| 10 | MW | One main competitive bidding process for 75%-90%[6] of the estimated target demand for the delivery window should take place 4-6 years ahead of the delivery window. Adjustment competitive bidding processes can be organised closer to delivery, taking into account the lead time for developing demand response and storage. |
| 11 | SR | Competitive bidding processes should take place no more than one year ahead of the delivery window. |

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| 12 | SR, MW | All participation rules and competitive bidding process requirements must be published at least 6 weeks before the deadline for submitting bids. |
| 13 | SR | Beneficiaries must be identified through a competitive bidding process with bids ranked according only to their price per de-rated unit of available capacity per year, and support paid according to either the initial bid or the clearing price. |
| 14 | MW | Beneficiaries must be identified through a competitive bidding process with bids ranked according only to their price per de-rated unit of available capacity per year, and support paid according to the clearing price[7]. |
| 15 | MW | Beneficiaries must be allowed to sell their capacity agreement to another capacity provider, up to at least 2 months before the start of the delivery window. |
| 16 | SR | Capacity agreements must have a duration of one year. |
| 17 | MW | Capacity agreements must in general cover one delivery window. Where beneficiaries undertake capital investments, longer capacity agreements may be made available. For every 25,000 EUR / de-rated MW, an additional year may be offered[8]. Fossil-fuelled generation assets may never be granted capacity agreements exceeding 15 years. In Member States where the three largest electricity generators in the territory covered by the capacity mechanism control (directly or indirectly, solely or jointly) at least 75% of domestic installed de-rated capacity in the year in which the competitive bidding process takes place, capacity agreements of at least 10 years must be available for projects exceeding a CAPEX threshold of 375,000 EUR/de-rated MW. |
| 18 | SR, MW | The delivery window must be a single fixed period of up to one year between 1 November of year Y until 31 October of year Y+1. |
| 19 | SR, MW | All beneficiaries must be activated (delivery or test) at least once per delivery window with ≤ 24 hrs notice. |
| 20 | SR, MW | Beneficiaries must face non-availability penalties whenever unavailable in a delivery period[9] or test. The non-availability payment must be the same for all technologies. A beneficiary less than 50% available in the delivery periods within a delivery window must be exposed to a penalty payment of at least its capacity revenues for the delivery window. Beneficiaries must not face penalties related to a lack of |

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| | | availability outside the delivery periods. Beneficiaries must pay unavailability penalties for the remaining life of a capacity agreement if they exit that capacity agreement early[10]. |
| 21 | MW | The approach regarding the participation of beneficiaries to ancillary services during the delivery period should be in line with the methodology of the adequacy assessment used to determine the need for and size of the measure. For ancillary services considered in the adequacy assessment as contributing to adequacy, beneficiaries must be allowed to offer these services in parallel to their capacity obligation and if available for the service would be simultaneously considered available for the capacity mechanism. For ancillary services not considered in the adequacy assessment as contributing to adequacy, Member States may choose either to exclude beneficiaries selling those services from participation in the capacity mechanism, or may allow voluntary participation in both the service and the capacity mechanism but with a risk of facing penalties under the capacity mechanism for resources unavailable in a delivery period due to the delivery of the service. |
| 22 | MW | If Member State applies both a capacity mechanism and a flexibility measure, or already has a flexibility measure in place, to avoid market barriers and/or overcompensation risks: <ul style="list-style-type: none"> - (a) capacity should be jointly procured[11]; or - (b) MSs may include non-fossil flexibility requirements identified in the flexibility needs assessment (in line with Article 19e(2)(c) of the Electricity Regulation) in their capacity mechanisms, for example requiring a minimum volume of non-fossil flexible capacity providing short term ramping services; or - (c) resources must choose between participating in only one measure, either the non-fossil flexibility support scheme or the capacity mechanism. The target demand in each measure should be adjusted to take account of participation in the other measure. |
| Avoidance of undue distortions to competition and trade and compatibility with Electricity Regulation Article 22(1-2) | | |
| 23 | SR | The profit of units participating in a strategic reserve must be the same, whether or not they are activated/dispatched. |
| 24 | SR, MW | Aid to the same capacity resource from more than one aid measure can be cumulated so long as overcompensation is avoided. If the Member State allows aid under the capacity mechanism to be cumulated with aid under other measures, the method used to comply with this |

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| | | requirement must be clearly set out in a public document, for example in the rules for the capacity mechanism and/or the rules for other schemes. |
| 25 | SR | At least 90% of any capacity mechanism costs not recovered through imbalance charges allocated in accordance with Article 22(2) of the Electricity Regulation must be allocated to consumers based on their consumption during at least 1% and at most 5% of the highest price hours (or market time units) each year (or each delivery window)[12]. Charges may be levied on balance responsible parties (such as suppliers). |
| 26 | MW | At least 90% of the capacity mechanism costs must be allocated to consumers based on their consumption during at least 1% and at most 5% of the highest price hours (or market time units) each year (or each delivery window)[13]. Charges may be levied on balance responsible parties (such as suppliers). |
| 27 | SR | The Member State must confirm that the capacity mechanism meets the requirements in Electricity Regulation Article 22(2). This also defines the delivery period. |
| 28 | SR | Availability is calculated as being equal to the power delivered[14]. |
| 29 | MW | Availability is calculated as the sum of (i) the power delivered; and (ii) the availability proposed on day ahead, intraday and/or balancing markets and which did not result in an activation[15], [16]. |

Footnotes

[1] 'European resource adequacy assessment (ERAA)' refers to the European Resource Adequacy assessment described in Article 23 of Electricity Regulation and in ACER Methodology for the European resource adequacy assessment of 2 October 2020.

[2] 'Reliability standard' means reliability standard as defined in Article 2, point 2 of the Annex I of the ACER Decision of 2 October 2020 on the Methodology for calculating the value of lost load, the cost of new entry, and the reliability standard; 'Cost of new entry (CONE)' means cost of new entry as defined in Article 2, point 2 of the Annex I of the ACER Decision of 2 October 2020 on the Methodology for calculating the value of lost load, the cost of new entry, and the reliability standard. 'Value of lost load (VOLL)' means value of lost load as defined in Article 2, point 9 of the Electricity Regulation. VOLL and CONE should be the figures provided by ACER as envisaged in the Commission's 3 March 2025 Report on the assessment of possibilities of streamlining and simplifying the process of applying a capacity mechanism, once available. In the meantime, they should be calculated according to the ACER Decision of 2 October 2020 on the Methodology for calculating the value of lost load, the cost of new entry, and the reliability standard.

[3] De-rating is an adjustment to the installed capacity of a capacity resource to identify its contribution to the adequacy need (reflecting the different technical characteristics and different reliability of different technologies in different bidding zones). The de-rating factors used should be those published by ACER/ENTSO-E as an output of the European Resource Adequacy Assessment for the relevant bidding zone, once available. In the

meantime, they must correspond to the ratio between (i) availability of the given technology in each bidding zone during scarcity situations and (ii) the installed capacity of the given technology (this calculation will be based on the latest available ERAA and will be updated at least every 2 years). De-rating factors must be calculated for every resource able to deliver its output continuously for at least 1 hour.

[4] See ACER decision: 'Technical specifications for cross-border participation in capacity mechanisms'.

[5] Member States are free to procure a lesser volume.

[6] If cross border capacity is not eligible to participate in the main auctions, at least 10% of the estimated volume required for the delivery window plus the maximum entry capacity must be demanded in the adjustment auctions.

[7] If flexibility requirements are included (see criterion 22), more expensive resources can be selected ahead of cheaper resource if necessary to fulfil the requirement, and a separate clearing price established for the resources fulfilling the flexibility requirement.

[8] For example, beneficiaries investing 50,000 EUR / de-rated MW may be offered contracts of up to 2 years; beneficiaries investing 150,000 EUR / de-rated MW may be offered contracts of up to 6 years, etc.

[9] 'Delivery period' is a period within the delivery window where contracted resources are required to be available, or face penalties. For strategic reserves, see criterion 27 in this table. For a market wide capacity mechanism, it can comprise the entirety of a delivery window, or just a part of it.

[10] Unless they are able to transfer their capacity agreement to another capacity provider in the secondary market. For multi-annual capacity agreements, the unavailability penalties can be limited to 4 years. Collateral can be required from capacity providers.

[11] This means that national authorities should set an objective for both flexibility needs and capacity mechanism needs to be procured during the same co-optimized auction. Participants provide their contribution to both the flexibility needs and to the capacity mechanism and offer a total price for the provision of the two services, or a menu of offers. The selection methodology should be such that it minimises the total cost of fulfilling both the flexibility needs and capacity mechanism needs, i.e. no alternative selections of beneficiaries can reach both flexibility needs and capacity mechanism needs at a lower cost.

[12] 'Price' refers to either the day ahead price or a closer to realtime wholesale market or imbalance settlement price. To avoid double-counting, where demand response and behind-the-meter resources participate directly in the capacity mechanism, they must also be subject to such charges for any electricity not consumed under delivery obligations.

[13] 'Price' refers to either the day ahead price or a closer to realtime wholesale market or imbalance settlement price. To avoid double-counting, where demand response and behind-the-meter resources participate directly in the capacity mechanism, they must also be subject to such charges for any electricity not consumed under delivery obligations.

[14] For demand response: power not consumed.

[15] When the availability is checked, the capacity is not necessarily activated, as capacity activation must be driven by energy market price signals. The only exception to that is testing requirements for capacity which the market never activates.

[16] Member States must avoid any double counting when the same capacity is available for several market timeframes (e.g. day-ahead, intraday and balancing).

Annex D Modifications to the CRM

| Modification | Modification effective date | Details | Category |
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| Administrative modifications include editorial and clerical changes, often aligning two parts of the code that were not in agreement. | | | |
| CMC_04_18 Capacity Auction Participation | 01/10/2018 | Clarified that while participants are required to offer their qualified Existing Capacity into a Capacity Auction, they are not obligated to offer New Capacity. This correction aligned Section F.2.1.1 with the principle already stated in Section F.7.1.1(h), ensuring consistency and avoiding misinterpretation. The change supports fair participation and reinforces the voluntary nature of offering New Capacity in the CRM | Administrative |
| CMC_08_18 Typographical Correction E.8.2.4 | 01/10/2018 | Editorial change no impact on code functionality or interpretation | Administrative |
| CMC_10_18 Paragraph B.10.4.1 Report on Capacity Auction | 01/10/2018 | Editorial change no impact on code functionality or interpretation | Administrative |
| CMC_11_18 Long Stop Date | 30/11/2018 | Implemented SEMC Decision SEM-18-030, introducing the concept of a Substantial Financial Close Period and updating the Long Stop Date definitions for single-year and multi-year capacity awards. Impact: Aligns code with regulatory decisions; no system changes | Administrative |
| CMC_05_19 Housekeeping Changes | 12/09/2019 | Fixed typographical errors and cross-reference duplications in multiple | Administrative |

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| | | sections (e.g., F.5.1.2(b), J.4.3.5, J.5.1.2, F.8.2.1), improving clarity and consistency. | |
| CMC_08_19 Housekeeping Mod E.8.2.5 & E.8.2.8 | 17/02/2020 | Corrected typographical errors in formulae within Sections E.8.2.5 and E.8.2.8 to remove ambiguity and ensure accurate calculations during Capacity Auction checks. | Administrative |
| CMC_07_21 E.4 Application for Qualification Update | 02/11/2021 | Introduced a Reduced Application for Qualification option in Section E.4, allowing participants to reuse previous data if nothing has changed since last qualification. | Administrative |
| CMC_05_22 Housekeeping Mod to Update Overlap between CMC_03_21 and CMC_04_21 | 01/07/2022 | Resolved a textual overlap between CMC_03_21 and CMC_04_21 in J.4.3.2(a), integrating both approved changes without conflict. | Administrative |
| CMC_14_23 LCC Violation Criteria | 03/10/2023 | Defined how Locational Capacity Constraints (LCC) should be violated when no feasible auction solution exists. Auction software will now minimise the cost of constraint violations. | Administrative |
| CMC_08_23 Typographical Correction Capacity Aggregation Threshold | 11/12/2023 | Corrected a reference from D.2.1.3 to D.3.1.3 in the definition of Capacity Aggregation Threshold. | Administrative |
| CMC_05_23 ARHL Issue Identified in CMDRB Decision | 09/02/2024 | Resolved a definition inconsistency between New and Existing Capacity arising from CMC_11_22, ensuring correct application of Annual Run Hour Limit (ARHL) de-rating factors. | Administrative |

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| CMC_05_24 Amendment to J.6.1.6 to recognise extensions granted under SEM-23-101 and SEM-23-108 | 01/10/2024 | Updated Section J.6.1.6 to formally recognise extensions granted under SEM-23-101 and SEM-23-108, preventing termination of capacity contracts due to regulatory delay. | Administrative |
| CMC_13_25 Amendments to Capacity Auction Timetable | 29/08/2025 | Amended the Capacity Market Code to clarify that the powers of the SOs and RAs provided under D.2.1.10 are not limited, thus allowing amendments to the Capacity Auction Timetable at short notice. | Administrative |
| CMC_10_25 Amendments to E7 | 29/08/2025 | Amend CMC Section E.7 to clarify qualification requirements, remove overlapping provisions, and streamline criteria for assessing new capacity. | Administrative |
| Updates to the mechanics of the auction process... | | | |
| CMC_12_18 Tolerance Class | 30/11/2018 | Introduced Tolerance Classes to allow differentiated Increase and Decrease Tolerances for units with emission or run-hour limits, replacing the previous use of Technology Class. | Auction Mechanics |
| CMC_14_18 Proposed Modifications in relation to the modifications of LCC MW limits by the RAs | 30/11/2018 | Allowed Regulatory Authorities to modify Locational Capacity Constraint (LCC) MW Limits, not just accept or set them to zero, ensuring consistency with changes to the all-island capacity requirement. | Auction Mechanics |
| CMC_03_19 Treatment of Exempt Price – Quantity Pairs | 20/03/2019 | Clarified handling of Exempt Price–Quantity Pairs in auctions, ensuring they do not clear before one-year offers unless necessary, and introduced | Auction Mechanics |

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| | | a formal definition to improve clarity. | |
| CMC_06_19 Modification to the Proportion of Delivered Capacity calculation (G.3.1.4) | 12/09/2019 | Clarified that Proportion of Delivered Capacity should be measured against Awarded Capacity, not Initial Capacity, and introduced definitions for Initial Maximum On Time to support flexible technologies. | Auction Mechanics |
| CMC_10_20 Change to determinations made in F.4.1.1 | 26/10/2020 | Clarified that Locational Capacity Constraint Required Quantity (LCCRQ) is a gross figure, and added a requirement for System Operators to determine already awarded capacity within LCC areas. | Auction Mechanics |
| CMC_11_20 Providing greater flexibility for the current interim Secondary Trading Notification (ISTN) process | 26/10/2020 | Reduced the notice period for submitting or amending ISTNs from 10 to 5 working days, and allowed 1-day amendments, improving flexibility for outage management. | Auction Mechanics |
| CMC_09_19B Addendum | 13/11/2020 | Corrected the Seller Limit calculation in ASTA (Section M.11.6.3) to ensure liquidity from awarded capacity is properly scaled for secondary trading. | Auction Mechanics |
| CMC_08_22 Locational Capacity Constraints Maximum Quantities | 30/09/2022 | Introduced a maximum limit for Locational Capacity Constraints, alongside existing minimums, to be published in the FAIP. | Auction Mechanics |
| CMC_17_23 Updates to LCC Areas | 03/10/2023 | Part B of this mod was approved, allowing non-standard methodologies to define LCC areas when the standard process doesn't capture system effects. | Auction Mechanics |

| Modifications to the process of the auction, including changing the information that must be published and auction timelines and dates to be adhered to for publication of qualification and results. | | | |
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| <p>CMC_07_18 Subsection F.9.5 Information Published following a Capacity Auction</p> | <p>01/10/2018</p> | <p>Introduced a new provision requiring the publication of provisional Capacity Auction results on the same basis as final results. This includes clearing prices, average awarded prices, qualification decisions, opt-out notifications, and provisional allocations. The change improves transparency and mitigates the risk of participants trading with inside information during the interim period between provisional and final results</p> | <p>Auction Process</p> |
| <p>CMC_09_18 Paragraph E.9.5.1 Publication of Qualification results</p> | <p>01/10/2018</p> | <p>CMC_09_18 amended Paragraph E.9.5.1 to ensure that the System Operators publish Qualification Results promptly after the Qualification Process concludes. The update clarified the scope of information to be published and reinforced the commitment to transparency and timely communication with market participants. This change supports better market awareness and planning ahead of Capacity Auctions.</p> | <p>Auction Process</p> |
| <p>CMC_02_20 Modification to the required time frame for a T-4 Capacity Auction to take place</p> | <p>12/02/2020</p> | <p>Introduced an interim arrangement allowing the T-4 CY2023/24 Capacity Auction to occur less than 42 months before the Capacity Year, due to delays in qualification results.</p> | <p>Auction Process</p> |

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| CMC_01_21 Amendment relating to the provision of the CAM Report following a Capacity Auction | 14/07/2021 | Amended B.10.4.1 to require the Capacity Auction Monitor (CAM) to submit their report two working days after provisional auction results are released to participants, rather than to the RAs. | Auction Process |
| CMC_02_21 Amendment to Capacity Market Code Modifications Workshop Agenda Timeline | 14/07/2021 | Updated B.12.7.1(f) to reduce the required lead time for issuing workshop agendas from 10 to 5 working days, resolving a conflict with the modification proposal deadline. | Auction Process |
| CMC_02_22 Timely Publication of FAIP | 08/07/2022 | Mandated that any delay in publishing the Final Auction Information Pack (FAIP) must result in a matching delay to the Capacity Auction. | Auction Process |
| CMC_03_22 Transparency on Publication of Qualification Results | 08/07/2022 | Required that Qualification Results be published before auctions, and any delay in publication must delay the auction by the same duration. | Auction Process |
| CMC_14_25 New Dates in Capacity Auction Timetable | 17/12/2025 | introduces new timeline milestones requiring the System Operators to submit indicative and final Locational Capacity Constraint values earlier, ensuring the Regulatory Authorities have sufficient time to review auction parameters. | Auction Process |
| CMC_09_25 Registration and Qualification Auction Timetable Milestones | 17/12/2025 | Introduces new registration and qualification timetable milestones to support the Capacity Market Platform and ensure more structured, efficient processing of applications | Auction Process |

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| | | for future capacity auctions | |
| Modifications required to align and comply with state aid guidelines, environmental compliance and transparency | | | |
| CMC_01_18 NICROS in the CRM | 01/10/2018 | Updated sections E.2.1.4, E.7.2.2, E.7.4.3, and the Glossary to exclude units holding Northern Ireland Renewable Obligation Certificates (NIROCs) from participating in the Capacity Remuneration Mechanism (CRM), in line with State aid rules. | Compliance |
| CMC_01_19 Interim Solution for Conducting Capacity Auctions | 20/03/2019 | Removed M.4.1.6 to comply with State aid approval, preventing over-procurement due to Locational Capacity Constraints. Reverts to enduring auction rules under F.8.3 and F.8.4. | Compliance |
| CMC_05_20 Implement amendments as required by the Clean Energy Package Regulation EU 2019/943 | 27/04/2020 | Implemented changes required by EU Regulation 2019/943, including CO ₂ emissions limits for capacity payments. Added checks at qualification, completion, and auction stages. | Compliance |
| CMC_09_19 Supplementary Interim Secondary Trading | 13/11/2020 | Introduced Alternative Secondary Trading Arrangements (ASTA) to allow bilateral trades of Reliability Options in the absence of a centralised secondary market. | Compliance |
| CMC_06_21 NIRO and DSU | 21/09/2021 | Closed a loophole by preventing Demand Sites receiving NIRO payments from forming part of a Capacity Market Unit (CMU). | Compliance |
| CMC_08_21 Ex-post verification of Compliance | 02/11/2021 | Added I.1.2A requiring ex-post verification of CO ₂ compliance for units burning mixed fuels, waste, or using CO ₂ capture as these will vary | Compliance |

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| | | considerable from year-to-year, aligning with ACER Opinion 22/2019. | |
| CMC_11_22 De-rating for Annual Run Hours Limits | 05/09/2022 | Applied an additional de-rating factor to combustion units with annual run hour limits, initially only for New Capacity. | Compliance |
| CMC_06_23 Second ARHL Modification to Complete SEM-22-044 | 10/01/2024 | Completed the implementation of Annual Run Hour Limit (ARHL) De-Rating Factors, including updates to calculations for AGUs and Grid Code Commissioned Capacity. | Compliance |
| CMC_12_25 RAs role in relation to FQDs | 29/08/2025 | reforms and clarifies the Regulatory Authorities' role in Final Qualification Decisions, shifting their function toward reviewing dispute outcomes rather than reassessing all qualification decisions. | Compliance |
| CMC_01_25 Provision of Information Related to Application Rejection under E.7 | 29/08/2025 | Makes it a requirement for System Operators to provide full, detailed reasons—and any consultant reports—for rejecting a qualification application under E.7, improving transparency and enabling more effective participant engagement during reconsideration | Compliance |
| Modifications to the CRM to maximise the chance of delivery of capacity, both through incentives for early delivery, extension of longstop dates to reflect 3rd party delays and how steps to completion are assessed | | | |
| CMC_03_20 Modification to the Long Stop Date for the CY2023/24 T-4 Capacity Auction | 30/03/2020 | Extended the Long Stop Date to 60 months after the auction run start for multi-year contracts in the CY2023/24 T-4 auction, maintaining the full delivery window. | Delivery of Capacity |
| CMC_09_20 Modification to the Long Stop Date for | 28/08/2020 | Extended the Long Stop Date to 31 December 2020 for capacity awarded | Delivery of Capacity |

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| the CY2020 / 21 T-1 Capacity Auction | | in the CY2020/21 T-1 auction, due to COVID-19-related delays in commissioning. | |
| CMC_07_20 Change in Technology Class | 18/01/2021 | Allowed participants to change the Technology Class of Awarded New Capacity if supported by a modified connection agreement, helping avoid delays due to contractor issues or system impacts. | Delivery of Capacity |
| CMC_04_21 Verification Requirements for Implementation Plan Milestones | 14/07/2021 | Updated J.4.3 to remove unnecessary verification obligations for DSUs/AGUs and made Certified Engineer reports optional unless requested by the System Operators. | Delivery of Capacity |
| CMC_09_21 Timeframe to consider SFC Extensions | 21/09/2021 | Added J.5.2.5 to require that applications to extend Substantial Financial Completion (SFC) be submitted at least 20 working days in advance, giving RAs time to assess. | Delivery of Capacity |
| CMC_12_21 Modification to the methodology for calculating the de-rated grid code commissioned capacity | 19/11/2021 | Removed the use of Gross De-Rating Factor from G.3.1.4A, ensuring Substantial Completion is assessed based on Awarded Capacity, not qualification values. | Delivery of Capacity |
| CMC_03_21 Modification to the provisions for Substantial Financial Completion | 19/11/2021 | Modified J.2.1.3 to allow DSUs/AGUs to meet Substantial Financial Completion via simplified contracts and increased termination charges, reflecting their shorter delivery timelines. | Delivery of Capacity |
| CMC_12_22 Remedial Action in the event of planning application to a project that qualifies under a Direction | 20/01/2023 | Allowed day-for-day extensions to Long Stop Dates and contract durations for projects delayed due to planning appeals or judicial reviews, specifically those | Delivery of Capacity |

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| | | qualified under a CRU Direction. | |
| CMC_13_22 Judicial Review Remedial Action | 20/01/2023 | Enabled extensions to Substantial Financial Completion and Long Stop Dates for projects affected by Third Party Judicial Reviews, with safeguards to prevent misuse. | Delivery of Capacity |
| CMC_15_22 Introduction of New Remedial Action to enable extensions due to planning and permitting delays | 20/01/2023 | Introduced a new remedial action to extend contract durations and Long Stop Dates for delays caused by planning or permitting challenges, including appeals and judicial reviews. | Delivery of Capacity |
| CMC_03_23 Amendment of Long Stop Date for T-1 Capacity Auction | 30/06/2023 | Extended the Long Stop Date for single-year T-1 contracts from 1 month to 3 months after the Capacity Year start, allowing more time for commissioning. | Delivery of Capacity |
| CMC_15_23 Amendment to Performance Securities for Extended Projects | 08/09/2023 | Aligned Performance Security posting dates with extensions granted under CMC_15_22 or similar delay-related modifications. Without this, projects could face high termination risk before planning decisions are final. | Delivery of Capacity |
| CMC_07_23 Special Application of ISTA | 02/10/2023 | Allowed Interim Secondary Trading Arrangements (ISTA) to apply to capacity unable to operate for the full year due to emissions limits or regulatory changes. | Delivery of Capacity |
| CMC_11_23 Amendment to Drafting Introduced Under Modification CMC_15_22 | 22/11/2023 | Extended the scope of planning delay extensions to include Article 17/18 Directions under Northern Ireland planning law, ensuring equal treatment across jurisdictions. | Delivery of Capacity |

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| CMC_19_23 Modification to implement the SEMC decision set out in SEM-23-038 and SEM-23-045 | 12/12/2023 | Implemented SEMC decisions SEM-23-038 and SEM-23-045, applying indexation to multi-year New Capacity awarded in the 2024/25 T-3 and 2025/26 T-4 auctions. | Delivery of Capacity |
| CMC_01_23 Amendment to Substantial Completion Drafting | 01/01/2024 | Allowed Regulatory Authorities to waive certain Balancing Market participation requirements if all other Substantial Completion criteria are met. | Delivery of Capacity |
| CMC_04_23 Introduction of remedial action for unforeseeable delays due to extraordinary supply chain impacts | 01/01/2024 | Introduced a mechanism to extend milestone dates for projects delayed by extraordinary supply chain issues, such as those caused by geopolitical events. | Delivery of Capacity |
| CMC_09_23 Removal of Section J.6.1.6 (1) | 01/01/2024 | Removed a clause that allowed termination of New Capacity for the first Capacity Year if it was deemed unlikely to deliver on time. The clause was seen as impractical and damaging to investor confidence. | Delivery of Capacity |
| CMC_10_23 Mitigation of Impact on Participants relating to 3rd Party Gas Connection delays | 01/01/2024 | Introduced remedial action for delays in third-party gas connections outside participant control. Allows milestone extensions and uses contract-based expert determination to resolve disputes. | Delivery of Capacity |
| CMC_23_23 Mitigation of impact on Participants relating to System Operator Grid Connection delays | 01/01/2024 | Allows extensions for delays in System Operator grid connections outside participant control. Uses independent expert review to assess delay attribution. | Delivery of Capacity |

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| CMC_25_23 Market Readiness Certification | 12/01/2024 | Introduced a Market Readiness Certificate to allow capacity to achieve Minimum or Substantial Completion before final Grid Code certification, enabling earlier market participation. | Delivery of Capacity |
| CMC_18_23 Amendment to definition of Third Party Extension Period | 16/02/2024 | Expanded the definition to cover additional planning delay scenarios, ensuring full coverage of delays due to appeals and judicial reviews in both jurisdictions. | Delivery of Capacity |
| CMC_10_24 Introduction of Intermediate Length Contracts | 17/09/2024 | Implemented SEM-24-035, allowing capacity investing >€100k/MWd to apply for contracts up to 5 years. Includes emissions limits and milestone requirements. | Delivery of Capacity |
| CMC_11_24 Implementation of Early Delivery Incentives according to SEMC Decision Paper SEM-24-037 | 17/09/2024 | Implemented SEM-24-037, allowing early payments (up to 1 year early) for multi-year New Capacity and incremental ILC capacity that delivers ahead of schedule. | Delivery of Capacity |
| CMC_09_24 Amendments to J.5.7 and J.5.8 | 27/09/2024 | Allowed participants to apply for extensions to Long Stop Date and/or Capacity Quantity End Date, even if expecting Minimum Completion. | Delivery of Capacity |
| CMC_08_24 Widening of Longstop Extension Process to Awarded Capacity for 2023-24 Auction | 27/09/2024 | Expanded the scope of Section J.5.8.1 to allow Awarded Capacity from the 2023/24 T-4 auction to apply for Long Stop Date extensions, not just New Capacity. | Delivery of Capacity |
| CMC_03_25 Clarification of Proportion of Delivered Capacity for multiple tranches | 16/07/2025 | clarifies and generalises how the Proportion of Delivered Capacity is calculated when a unit has multiple tranches of Awarded New Capacity, ensuring consistent | Delivery of Capacity |

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| | | measurement and alignment with qualification rules. | |
| Modifications to remove negative impacts from code on the financing of new capacity, improvement of transparency and alignment with market standards | | | |
| CMC_02_18 Permitted Disclosures – Credit Agencies | 01/10/2018 | Permit the disclosure of confidential information to credit rating agencies, alongside financial institutions. This change supports market participants like ESB GWM in fulfilling their obligations to maintain credit ratings, ensuring that such disclosures are legally covered and consistent with confidentiality standards | Finance |
| CMC_13_18 Modification to Letter of Credit | 30/11/2018 | Corrected references in Appendix H to specify the SEM Bank acting on behalf of the System Operators, ensuring consistency with other sections of the Code. | Finance |
| CMC_02_19 Negative Interest | 20/03/2019 | Permitted negative interest to be applied to credit balances held with the SEM Bank, aligning with ECB practices and addressing financial impacts on the bank. | Finance |
| CMC_01_22 New Interdependent Combined Units | 08/07/2022 | Allowed new Candidate Units with shared infrastructure (e.g. common grid connection) to be combined into a single Capacity Market Unit, even if above the De Minimis Threshold. | Finance |
| CMC_04_22 New Reference Rates for Default Interest | 30/09/2022 | Replaced LIBOR with SONIA (GBP) and ESTER (EUR) as reference rates for calculating Default Interest, following LIBOR's discontinuation. | Finance |
| CMC_16_23 Extension to New | 01/01/2024 | Granted up to 343 days extension for New | Finance |

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| Capacity Impacted by Indexation | | Capacity impacted by delays in the SEMC's indexation decision (SEM-23-038), acknowledging inflation-related investment uncertainty. |
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Annex E Overview of outcome of EY review

| Question | Sub-question | Impact | Potential Remedies | Benefit | Feasibility |
|--|--|--------|--|-----------|-------------|
| 1: Was sufficient capacity procured in capacity auctions? | 1.1: Is the SEM reliability standard adequate? | 3 | Move to tighter reliability standard in line with other European markets. | Medium | Very High |
| | 1.2: Did TSO forecasts identify the growing capacity shortfall? | 5 | Greater transparency of target setting through a panel of technical experts (PTE) assessment of EirGrid recommendations, with findings published, and explanation of process by which GCS forecasts are translated to Target Volume to procure in capacity auctions. | High | Medium |
| | 1.3: Did the RAs make appropriate adjustments to TSOs recommendations? | 5 | More explicit accounting of non-delivery in setting target, with two options for implementation: <ul style="list-style-type: none"> ▪ Introduce process to monitor progress reports for early indication of non-delivery; OR ▪ Apply a standardised adjustment to capacity requirement to account for likelihood of non-delivery, review inputs to adjustment % on a periodic basis. | Very High | Very High |
| 2: Did capacity auctions attract sufficient participation? | 2.1: Did the auctions attract sufficient participation? | 5 | Greater investment in infrastructure to enable more competitive all-island market and reducing pressure for new build to be situated in particular locations. | High | Medium |
| | 2.2: Are bidding restrictions on | 1 | None required | - | - |

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| | existing plants prompting plants to close sooner? | | | | |
| | 2.3: Have new build projects been appropriately pre-qualified for auctions? | 3 | Requirement of new prospective capacity to have all necessary consents to pre-qualify for auction. This remedy is potentially redundant if remedy 3.1 is taken forward (i.e. extending auction lead times). | Very High | High |
| 3: Did new capacity procured in auctions get built? | 3.1: Are T-4 timelines long enough to enable new build to deliver? | 5 | Increase lead time to at least 4 years from announcement of auction results to start of capacity delivery year. | Very High | Medium |
| | 3.2: Are the incentives for delivery too low to ensure new capacity procured is actually built? | 3 | Increase performance securities following the auction | Medium | Medium |
| | 3.3: Is there sufficient monitoring of new build projects' progress against milestones? | 3 | Require performance security to be lodged prior to auction. | High | Medium |
| | 3.4: Have the RAs made appropriate | 4 | More permissive approach to requests for extensions from new build projects (where likelihood of delivery is high). | Medium | Very High |

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| | decisions on requests for extensions by new build projects? | | | | |
| 4: Was the capacity procured of sufficient value? | 4.1: Are there adequate incentives for generation to be reliable? | 5 | <ul style="list-style-type: none"> ▪ Recalibrating the administrative scarcity pricing function so BM pricing better reflects market scarcity and causes a higher frequency of periods with prices above the RO strike price. ▪ Refining the principle of flagging interconnector actions from SEM BM prices to drive prices that are more likely to exceed the RO strike price and more reflective of the value of generation. ▪ Greater monitoring of technology performance in stress events to inform future de-rating factor setting. ▪ Applying administrative penalties for non-delivery to plants in specific locations where an amber alert has been raised and a plant is unavailable. ▪ Implement additional physical checks on existing capacity providers in periods with no stress events. | High | High |
| | 4.2: Are there adequate incentives for DSUs to be reliable? | 4 | <ul style="list-style-type: none"> ▪ Implement baseline methodology for assessing the contribution of DSUs in reducing energy demand. ▪ Pay DSUs for negative generation up to the RO strike price. ▪ Determine energy-only stack within balancing market and compensate generators if instructed not to run for system reasons. | High | Very High |

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| | | | <ul style="list-style-type: none"> ▪ Set single derating factor for DSUs regardless of size. ▪ Implement provision for secondary trading for capacity providers. | | |
| | 4.3: Does the CRM adequately value efficient generation technologies? | 3 | <ul style="list-style-type: none"> ▪ Allow 15-year contracts for the most capital-intensive new build (i.e. CCGTs, long duration storage). ▪ Making ancillary service contracts more accessible to new build by creating ancillary service contracts with a longer lead-time and duration in line with the CRM and by procuring the products in a single integrated auction process. | Medium | Low |



We don't care much about making history.
We care about making future.

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