An Coimisiún um Rialáil Fóntais

Commission for Regulation of Utilities

Price Review Six

Distribution Revenue 2026 – 2030

Draft Determination Paper

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CRU Strategic Plan 2025-27

Executive Summary

Purpose of this document

The Commission for Regulation of Utilities (CRU) is responsible for the economic regulation of the electricity network companies in Ireland. To do this, the CRU sets Price Reviews which limit the revenues that the relevant licensees can recover from electricity customers. Price Reviews are set every 5 years and the upcoming Price Review Six (PR6) will cover the period, 1st January 2026 to 31st December 2030.

This document sets out the CRU's Draft Determination on the allowed expenditure and the associated allowed revenues for ESB Networks (ESBN), licensed by the CRU as the Distribution System Operator (DSO).

The CRU is seeking stakeholder views on all aspects of the CRU's Draft Determination (see Appendix 1). Responses will be considered prior to the publication of the CRU's Final Determination.

Background to PR6 and lessons learned from PR5

The electricity distribution network connects all households and the vast majority of businesses to Ireland's electricity system. Ireland's distribution networks require a significant step up in investment to accommodate the increasing numbers of connections, the electrification of heat and transport, the digitalisation of the economy and the need to integrate increasing levels of renewable technologies to the grid.

For PR6, the CRU's Strategy Paper set out the strategic approach, objectives and outcomes that should be delivered by ESBN and EirGrid (together the "network companies") including the ambition to build on the progress made through the previous price review period, Price Review 5 (PR5).[1]

It is important to recognise that PR5 represented a significant change for the regulatory framework in Ireland, with increased importance placed on achieving outcomes and objectives, particularly around decarbonisation, relative to previous price reviews. Overall, this has driven positive, but mixed, results for customers, with evidence that network companies have helped progress delivery of some decarbonisation and net zero targets, but fallen short in other areas such as resolving reliability issues.

Another positive development in PR5, was the introduction of the Agile Investment Framework (AIF), comprising of a series of mechanisms to allow access to additional revenues during the price review period, thus allowing for a more flexible approach to network investments. However lessons learned from its implementation point to the need for further clarity and codification before the start of the price review period.

In the Price Review Six Regulatory Framework Paper (CRU202590) the CRU sets out the proposals for the PR6 regulatory framework including the approach to cost recovery and managing uncertainty, performance incentives, and reporting, monitoring and governance arrangements. For the purpose of this document, which sets out the allowed expenditure and revenues, it is important to understand the changes that have been proposed to the AIF, which is now referred to as the Agile Investment and Monitoring Framework (AIMF). The PR6 regulatory framework will include a suite of proposed mechanisms to deal with the inevitable changes in priorities and circumstances (and hence costs) that will arise over the period.

[1] CRU202427 – Price Review Six Strategy Paper

Ireland's electricity system is undergoing rapid change, which is driving a significant step change in the level of investment required in the networks, while also increasing the overall level of uncertainty around the timings, pathways and delivery of different projects and investment programmes. The CRU expects that network companies' allowed expenditure and associated revenues will need to adjust during the price review period to reflect changes in scope and or investment pathway. As noted above, the AIF was introduced in PR5 to provide agility and flexibility, but in practice network companies did not have confidence that it would sufficiently allow for flexing up/down of expenditure and revenues and it struggled to deal with the degree of change that actually occurred during PR5. For example, it was not designed to manage the step-changes associated with Climate Action Plan (CAP) 2021 and the security of supply challenges that arose mid-period.

The newly proposed AIMF for PR6, building on the AIF, is expected to perform a fundamental role as an agile, light-touch framework to provide the pathway for network companies to flexibly access additional expenditure and associated revenues during the period.

To give confidence to network companies that additional revenues will be available when required, and to manage the level of risk that customers should bear, the CRU proposes to provide a clear *ex-ante* commitment on the envelope of revenue allowances that may ultimately be required to deliver on the PR6 outcomes and objectives.

As set out in this document, the CRU have proposed:

- *ex-ante* <u>baseline</u> operational expenditure (opex) and capital expenditure (capex) allowances – as discussed above, part of which are ring-fenced to particular programmes as part of delivery obligations; and
- <u>opex and capex allowances</u> which the CRU confirms are accessible to companies by the AIMF (also referred to as 'high case' allowances).

The approved baseline allowances are forecast business and PR6 project / programme costs, for which the CRU currently has higher confidence in the need, additionality, scope and cost based on the technical reports provided by the CRU's advisors, CEPA and GHD (please refer to [CEPA and GHD Cost Annexes]).

The approved high case allowances are expenditure that the CRU confirms may be needed and is approving as accessible during PR6. Network companies are expected to seek approval through the AIMF's targeted (scheme / category specific) reopeners and volume driver mechanisms for additional allowances in the high case to be released into allowed revenues during PR6 (refer to [CRU PR6 Regulatory Framework paper] for more information on these proposals).

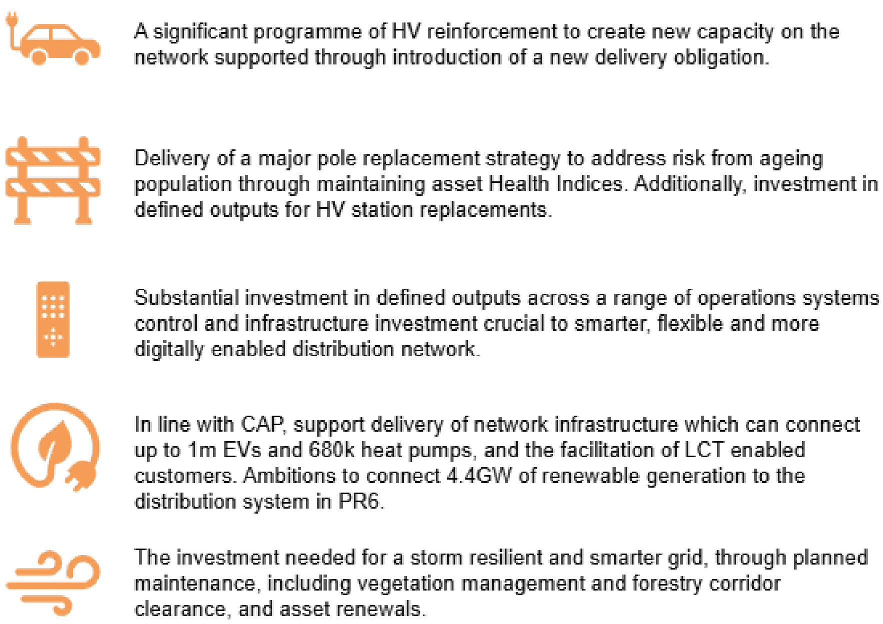
The CRU's proposed evolution of the regulatory framework, set out as part of this Draft Determination, improves funding flexibility and introduces clearer accountability for delivery. It reflects the CRU's commitment to enable delivery of the infrastructure required to meet the evolving needs of the distribution system, while safeguarding the interests of current and future consumers. The CRU will review these baseline and high allowances ahead of Final Determination in light of the responses and representations made to this consultation.

What PR6 is expected to deliver for customers

The Network Needs Assessment paper (CRU202597) published alongside this Draft Determination highlights the significant technical challenges from a network perspective in the achievement of Ireland's net zero ambition. This includes the need for substantial upgrades to the electricity grid to accommodate the anticipated increase in demand from the electrification of heat and transport, provision of new connections and integration of renewable energy sources, as well as to overcome existing network constraints.

The PR6 Business Plans submitted by the DSO focussed on addressing these issues. The CRU supports the need to invest in the network to provide sufficient capacity which is a critical enabler to economic growth and the drive to decarbonisation. A snapshot of what PR6 is expected to deliver for customers is set out below.

Figure 1: Expected Delivery in PR6



Review of Historic and Forecast Expenditure

The CRU has applied a rigorous cost assessment process that ensures only well-justified and efficient expenditure is included within the allowed revenues. This includes both an *ex-post*, or historic review, into the actual outturn expenditure incurred in PR5, and the associated outputs, and an *ex-ante* review into forecast expenditure for PR6. The steps taken and elements considered in the cost assessment are set out in the introduction to Section 4 below.

The following sub sections set out a brief summary of the CRU's historic (2021 - 2025) and forecast (2026 - 2030) review of DSO costs.

The CRU expects the DSO to rely on their internal governance processes to assess and justify their cost requests, providing additional information that sufficiently supports their cost requests in response to this Draft Determination. Once received, and if the additional information is deemed satisfactory, the CRU will include the additional expenditure allowance, and associated revenues, in the Final Determination. Therefore, the allowances approved in the Final Determination may be higher than the allowances set out in the baseline recommendation in this paper.

Unless otherwise stated, all prices stated within this document are expressed as real prices at 2024 price levels, based on the Harmonised Index of Consumer Prices (HICP). Also note that for PR5 expenditure this is often referred to as outturn expenditure, although it includes a mix of actual outturn costs for 2021 - 2023, and a mix of some outturn and budgeted or forecast costs for 2024 - 2025.

PR5 Historic Expenditure Review (2021 - 2025)

The DSO's total opex in PR5 was €2.03bn against an allowance of €1.96bn, resulting in a €71.8m overspend. The controllable opex component, was €1.68bn, against an allowance of €1.56bn resulting in an overspend of €123.4m (7.9%).[2]

This was driven primarily by overspends on meter reading (40.9%) costs, asset management (38.6%) and customer relations (55.3%). For meter reading, the impact of the COVID-19 pandemic was explained by the DSO as being a key driver for overspends, given the impact this

[2] The DSO's opex can be split into controllable and non-controllable opex. The review focusses on controllable opex, as this represents costs that the DSO has influence over, unlike non-controllable opex which comprises Network Rates and the CRU Levy.

had on the smart meter rollout and associated work programmes. Although other factors, such as increasing volume of connection applications and programmes to transform DSO's customer communication and experience functions have also contributed to the overall overspend on opex.

Overall, the historic review of PR5 opex concluded that all of the DSO's outturn expenditure should be recovered, except for costs associated with miscellaneous non-regulatory category. There was no *ex-ante* allowance provided for this cost category in PR5 but, the DSO has incurred €9.7m of opex.

Table 1 below provides a summary of the *ex-ante* opex allowances, PR5 outturn expenditure, and the results of the CRU's historic review of expenditure.

Table 1: Summary of PR5 Opex

PR5 DSO *Ex-post* Opex Allowance Categories	PR5 *Ex-ante* Allowance (€m)	PR5 Outturn (€m)	PR5 *Ex-post* Allowance (€m)
Total DSO Controllable Opex	1,555.5	1,678.9	1,669.2
Total DSO Non-Controllable Opex	399.9	348.3	348.3
Total	**1,955.4**	**2,027.2**	**2,017.5**

For capex, the forecast outturn expenditure in PR5 was €3.7bn, against an allowance of €3.9bn resulting in a €157.2m underspend. Over the PR5 period the DSO reprioritised its capex towards load-related capex to accommodate a significantly higher number of new business connections and reinforcements than had been forecasted at the beginning of the PR5 period. The primary drivers for the capex underspends are associated with underspend in generator connections and smart metering programme, which resulted in an underspend of 59% and 35% respectively.

Overall, the historic review of PR5 capex concluded that all of the DSO's outturn expenditure should be recovered, except for costs associated with HV reinforcement projects (€84.4m). This is due to a lack of clear information about the final outturn cost for, further information about the nature of outturn costs (continuity improvement) and approval of additional expenditure (system control) is required.

Table 2 below provides a summary of the *ex-ante* capex allowances, PR5 outturn expenditure, and the results of the CRU's historic review of expenditure.

Table 2: Summary of PR5 Capex

PR5 DSO *Ex-post* Capex Allowance Categories	PR5 *Ex-ante* Allowance (€m)	PR5 Outturn/Forecast (€m)	PR5 *Ex-post* Allowance (€m)
Total Network Capex	**3,494.2**	**3,286.6**	**3,202.2**
1. Load Related New Business	591.3	683.7	**683.7**
2. Load Related Reinforcement	625.1	628.3	**600.1**
3. Other Load Related	421.9	339.7	**339.7**
4. Non-Load Related (Asset Renewals)	540.6	593.1	**593.1**
5. Non-Load Related (Other)	1,315.4	1,041.8	**985.5**
Total Non-Network Capex	**379.2**	**429.6**	**429.6**
1. Head Office Accommodation/Vehicles	226.1	213.7	**213.7**
2. Distribution Asset Management (Support & Planning)	88.4	137.5	**137.5**
3. Enterprise Application	0.0	0.0	**0.0**
4. Telecoms	64.6	78.5	**78.5**
Total Capex	**3,873.4**	**3,716.2**	**3,631.8**

More detail is provided on the PR5 historic review of the DSO's opex and capex in Section 3.

PR6 Forecast Expenditure Review (2026-2030)

This Draft Determination for PR6 presents a significant step change in allowed expenditure when compared to the previous price review period. For the DSO, the CRU is proposing to approve a baseline expenditure allowance of €7.7bn and a total expenditure envelope allowance of €9.8bn over the PR6 period, representing a 70.4% increase compared to PR5 outturn expenditure. This increase is primarily driven by the need to accelerate the net zero transition, address existing constraints on the system and improve the resilience of the networks. The CRU's review of this forecast expenditure flagged concerns around instances of limited or insufficient information. In addition, the proposed PR6 allowances also reflect concerns around deliverability and the readiness for some of these investment programmes to proceed.

The DSO requested a total allowance for PR6 of €10.5bn (including baseline and what it had termed as an Agile Investment Framework component). For the controllable opex component the DSO proposed an allowance of €2.59bn. This represents a *circa* €907.2m (54.0%) increase relative PR5 outturn expenditure. This significant increase is driven primarily by Planned Maintenance, Meter Reading and System Control, which represent 44.4%, 29.4% and 9.2% of the increase in spend respectively.

Table 3 below provides a summary of the DSO's requested opex, and the results of the CRU's proposed PR6 allowed opex following the review of this expenditure.

Table 3: Summary of PR6 Opex Draft Determination Proposals

PR6 DSO *Ex-ante* Opex Allowance	DSO Request (€m)		Draft Determination (€m)	
Categories	**Baseline**	**High**	**Baseline**	**High**
Total DSO Controllable opex	2,586.1	2,586.1	2,084.5	2,366.1
Total DSO Non-Controllable opex	425.2	425.2	424.9	424.9
Total (excluding RPEs and Ongoing Efficiency)	**3,011.3**	**3,011.3**	**2,509.4**	**2,761.0**
Total (including RPEs and Ongoing Efficiency) [3]	**-**	**-**	**2,517.6**	**2,769.2**

For capex, the DSO has requested a significant increase compared to PR5 outturn. The total net capex request for PR6 is €6.73bn, which represents a 111% (€3.54bn) increase compared to the DSO's PR5 outturn expenditure of €3.18bn.

The increase is largely driven by increased expenditure associated with new demand connections (€868.2m, representing a 33% increase), High Voltage (HV) reinforcements (€1.60bn, representing a 424% increase) and Medium Voltage/Low Voltage (MV/LV) system reinforcement costs (€792.6m, representing an increase of 207%). The DSO has also requested a 300% increase in generation costs to €369.6m (which includes €31.1m of the DSO's proposed AIF based allowances) against PR5 outturn of €92.5m.

Table 4 below provides a summary of the DSO's requested capex, and the results of the CRU's proposed PR6 allowed capex following the review of this expenditure.

Table 4: Summary of PR6 Capex Draft Determination Proposals

	DSO Request (€m)		Draft Determination (€m)	
PR6 DSO *Ex-ante* Capex Allowance				
Categories	**Baseline**	**High**	**Baseline**	**High**
1. Load Related New Business	921.4	921.4	797.0	911.8
2. Load Related Reinforcement	2,207.9	2,714.2	1,816.0	2,585.3
3. Load Related Generator Connections	338.5	369.6	198.7	369.5
4. Other Load Related	343.5	343.5	287.9	315.5
5. Non-Load Related (Asset Renewals)	936.5	1,106.1	629.4	916.3
6. Non-Load Related (Other)	1,082.9	1,250.9	795.3	1,214.7
Total Network Capex	**5,830.9**	**6,705.7**	**4,524.3**	**6,313.1**

[3] We note that we requested information on ongoing efficiencies in the Business Plan Questionnaire Guidance, alongside assumptions and justifications, in the PR6 forecasts.

1. Head Office Accommodation/Vehicles	434.2	434.2	359.3	359.3
2. Distribution Asset Management (Support & Planning)	193.5	193.5	171.5	171.5
3. Enterprise Application	1.7	1.7	0.6	1.7
4. Telecoms	157.4	157.4	139.1	157.7
Total Non-Network Capex	**786.8**	**786.8**	**670.3**	**690.3**
Total[4]	**6,617.7**	**7,492.5**	**5,194.9**	**7,003.4**

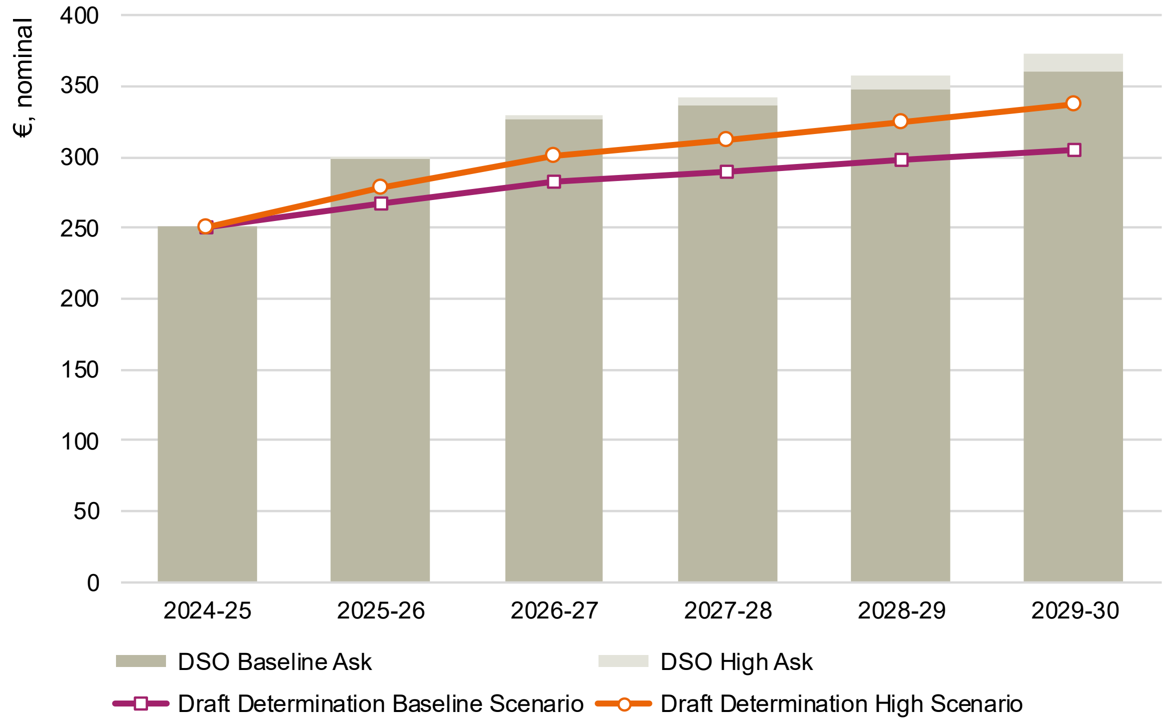
The CRU requires further information to support the requests. Specifically, either some or all of the PR6 assessment gateways (need, additionality and efficiency of costs) have not been met. These areas of further information indicate the potential for a change in revenues between Draft Determination and Final Determination. This is subject to additional, targeted, information being submitted by the DSO, which will be considered during the consultation period and prior to Final Determination. More detail is provided on the PR5 historic review of the DSO's opex and capex in Section 3.

Consumer Impact Summary

Distribution-related domestic network costs are expected to increase (in nominal terms), when comparing relevant estimated charges for 2029/30 with 2024/25. The CRU's assessment included two different consumer impact scenarios relating to the Draft Determination: a baseline and a high scenario (see Table 4 above). Figure 2 below shows the potential consumer impacts of the Draft Determination proposals on the distribution network charges which relate to an archetypical domestic customer, as well as the impact of the baseline and high company asks.

[4] No RPEs and Ongoing Efficiency assumptions have been applied *ex-ante* to the capex allowances.

Figure 2: Distribution Network Costs: Draft Determination Domestic Customer Impacts (Nominal Values)



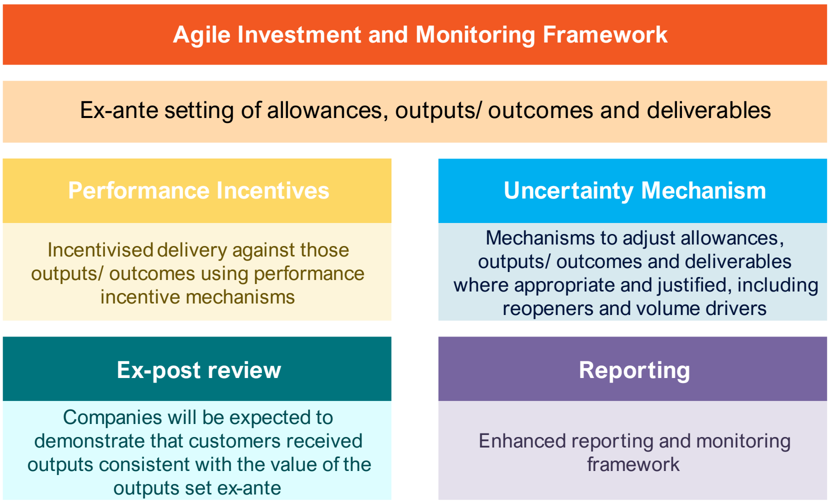
Regulatory Framework and Delivering for Consumers

As in PR5, the proposed building blocks of the PR6 Regulatory Framework can be considered in several broad categories. In PR6 this will be referred to as the Agile Investment and Monitoring Framework (AIMF) and will consist of the following components:

- ***Ex-ante* setting** of allowances, outputs/ outcomes and deliverables – including regulatory commitment by the CRU to a high case as well as a baseline envelope of allowed revenues;
- **Incentivised delivery** against those outputs/ outcomes using performance incentive mechanisms;
- Mechanisms **to adjust allowances**, outputs/ outcomes and deliverables where appropriate and justified during the PR6 period, including reopeners and volume drivers.
- The ***ex-post* review** at the end of the PR6 period; and
- An **enhanced reporting and monitoring** framework.

Each of these building blocks will be supported through an evolved focus on delivery of specified outputs and outcomes given the significant step up in investment.

Figure 3: Agile Investment and Monitoring Framework Building Blocks



Finance and Cost of Capital

The CRU proposes to allow a real pre-tax cost of capital of 3.85% for the DSO in the PR6 period. This is lower than ESBN's point estimate of 4.23% primarily due to a difference in the inflation adjustment estimates. For PR6, the CRU has looked at estimating the cost of debt for the DSO by taking a weighted average of the embedded debt and new debt. As in the previous price reviews, the CRU has used a notional capital structure to ensure that the consumers only pay for an efficient cost of capital structure.

The financeability assessment carried out for the DSO by CEPA suggests that based on the notional financial metrics of ESBN and investment plans over PR6, the proposed WACC of 3.85% is consistent with ESBN being adequately financeable over the PR6 period with sufficient headroom and a simulated preliminary credit rating that is investment grade under plausible downside shocks[5].

Table 5 below summarises the DSO cost of capital proposals for PR6 alongside CEPA's proposals.

[5] The simulated outcome estimated for ESB Networks follows Moody's 2022 Regulated Electric & Gas Networks Rating Methodology paper.

Table 5: Cost of Capital Estimates and Proposals - DSO

Parameter	CEPA PR6		DSO PR6	
	Lower	Upper	Lower	Upper
Cost of debt (real, pre-tax)	**1.28%**	**1.70%**	**1.25%**	**1.69%**
Tax	12.5%	15%	12.5%	
Cost of equity (real, pre-tax)	**5.22%**	**6.38%**	**5.17%**	**6.18%**
Notional Gearing	55%			
WACC (real, pre-tax)	**3.05%**	**3.81%**	**3.01%**	**3.71%**
Inflation adjustment	0.10%	0.40%	0.58%	0.83%
WACC (real, pre-tax) after inflation expectations adjustment	**3.15%**	**4.21%**	**3.60%**	**4.54%**
Cost of Capital	**P67=3.85%**		**P67=4.23%**	

Public/Customer Impact Statement

The CRU's Distribution Price Review Draft Determination sets the framework for how much money ESBN can recover and what must be delivered in return. These decisions not only impact consumer bills and the quality of service they receive, but also play a crucial role in enabling increased levels of renewable energy, supporting decarbonisation, achieving climate targets, enhancing energy independence, and fostering price stability in the long term.

Ireland's electricity networks deliver secure electricity supplies to homes and businesses in the country. The CRU allows EirGrid and ESB Networks ("the network companies") to charge money towards the cost of building, safely operating and maintaining the electricity system in Ireland. These charges are passed onto suppliers, which are then typically reflected in customers' electricity bills and make up the network companies' revenue allowances.

The CRU's role is to protect electricity customers by ensuring that the network companies spend customers' money appropriately and efficiently to deliver necessary services and make necessary investments in infrastructure. The CRU does this through what is called a Price Review which is carried out every five years. The current Price Review (PR5) started in 2021 and will end in 2025. PR6 will follow PR5 and will determine the use of system charges for the period 2026 to 2030, and therefore, will have an impact on customers electricity bills over that period.

Distribution networks are critical to delivering electricity safely and reliably to homes and businesses across Ireland. Through this Draft Determination, the CRU aims to strike the right balance between ensuring consumers only pay for well justified plans and proposals and the need to invest in smarter, greener and more resilient energy for the future.

The proposed allowed revenues set out in this Draft Determination paper are targeted at delivering value for customers while enabling the network companies to deliver on outcomes and objectives through PR6 linked to Ireland's decarbonisation, climate change and renewable energy ambitions. The CRU considers it critical that throughout PR6 network companies provide resilient electricity networks and supplies while supporting high-quality, secure and cost-effective services to customers and networks users.

The impact of this Draft Determination proposal on electricity consumers has been analysed in detail in the accompanying Information Paper on the topic (CRU202591). Overall, distribution-related network charges for the archetypical domestic customer are expected to increase (in nominal terms) by €54 in the Draft Determination baseline scenario and by €87 in the high scenario, when comparing relevant forecast charges for 2029/30 with 2024/25.

Table of Contents

Glossary of Terms and Abbreviations

Abbreviation or Term	Definition or Meaning
ADMD	After Demand Maximum Diversity
AIF	Agile Investment Framework – PR5
AIFM	Agile Investment and Monitoring Framework-PR6
AICR	Automatic Intelligent Call Routing
BPQ	Business Plan Questionnaire
CAP	Climate Action Plan
CAPM	Capital Asset Pricing Model
CEPA	Cambridge Economic Policy Associates
CoD	Cost of Debt
CoE	Cost of Equity
CPI	Consumer Price Index
DAC	Designated Activity Company
DAO	Distribution Assets Owner
DMSO	Distribution Markets and System Operation
DNO	Distribution Network Operator
DUoS	Distribution Use of System
DSO	Distribution System Operator
DMS	Dimson, Marsh and Staunton
ECP	Electricity Connection Policy
ESBN	Electricity Supply Board Network
FFO	Funds For Operation
GHD	Gutteridge Haskins and Davey Ltd.
GMPRN	Group Meter Point Reference Number
GDP	Gross Domestic Product
HICP	Harmonised Index of Consumer Price
HV	High Voltage
IDC	Interest During Construction
KPI	Key Performance Indicators
LCT	Low Carbon Technologies
LiDAR	Light Detection and Ranging

LV	Low Voltage
MEC	Maximum Export Capacity
MRSO	Meter Registration System Operator
MV	Medium voltage
NECP	National Energy and Climate Plan
NEDS	National Energy Demand Strategy
NN,LC	National Network, Local Connections
NDCC	National Distribution Control Centre
NIS-2	Directive (EU) 2022/2555 of the European Parliament and of the Council of 14 December 2022 on measures for a high common level of cybersecurity across the Union
NSMP	National Smart Metering Programme
NT	New Technician
O&M	Operational and Maintenance
OHL	Overhead Line
PAYG	pay-as-you-go meters
PR1	Price Review 1
PR2	Price Review 2
PR3	Price Review 3
PR4	Price Review 4
PR5	Price Review 5
PR6	Price Review 6
RAB	Regulatory asset base
RPE	Real Price Effects
RfR	Risk-free Rate
RCF	Revolving Credit Facility
QH	Quarter Hour
RES-E	Renewable Energy Source – Electricity
SEM	Single Electricity Market
SMOC	Smart Metering Operations Centre
SNSP	System Non-Synchronous Penetration
TAO	Transmission Asset Owner
TMR	Total Market Rate
the Act	Electricity Regulation 1999 Act, as amended

TUoS	Transmission Use of System
TSO	Transmission System Operator
TPS	Total Factor Productivity
WACC	Weighted Average Cost of Capital

1 Background

The CRU is responsible for the economic regulation of the system operators and asset owners for electricity transmission and distribution systems in Ireland. To do this, the CRU carries out reviews of the allowed revenue for the transmission and distribution businesses through price reviews. Price reviews set the revenue that the relevant network company can recover from electricity consumers and are set every five years. The transmission business consists of EirGrid, licensed by the CRU as the Transmission System Operator (TSO) and ESB, acting through its ESB Networks business unit, is the licensed Transmission Asset Owner (TAO). ESB Networks DAC is licensed by the CRU as Distribution System Operator (DSO), and ESB, acting through its ESB Networks business unit, is the licensed Distribution Assets Owner (DAO).

In December 2020, the CRU set its price reviews for the Price Review 5 (PR5) period for EirGrid as TSO, and for ESB Networks as TAO and DSO/DAO. PR5 comes to an end in 2025, therefore, the CRU has initiated the review of the allowed revenue for the transmission and distribution businesses for the next price review period (PR6). PR6 will cover the five-year period from 2026 to 2030. This Draft Determination outlines the proposed allowed revenues that the DSO can recover and access (as part of the Agile Investment and Monitoring Framework (AIMF)) during the PR6 period.

In recent years, there have been major policy developments at national and European level that have and will continue to drive significant change in the energy sector. European policies have set EU-wide targets to achieve carbon neutrality (net-zero emissions) by 2050. To facilitate this, national policies recognise the need to promote the large-scale deployment of renewables which will be critical to decarbonising the power sector as well as enabling the electrification of other technologies. The major policy developments that impact the strategic context of PR6 are described in detail in Section 2 of the PR6 Strategy Paper[6].

We are seeking comments from members of the public, the industry, customers and all interested parties on proposals put forward in this paper. These include the proposed opex allowance, and capital expenditure allowance over the PR6 period. The CRU is also seeking stakeholders' views on where further information is required of the DSO's revenues request and the proposed regulatory framework (CRU202590). Responses will assist and inform the CRU in reaching its final decision on the DSO's revenue allowance.

[6] CRU202427 – Price Review Six Strategy Paper

The CRU has acquired the services of economic and engineering experts to assist in the review of the DSO's historic costs and performance in PR5, forecast costs for PR6, and setting allowed revenues. Cambridge Economic Policy Associates (CEPA) with the support of Gutteridge, Haskins and Davey (GHD) were procured to provide advice on the economic, policy and technical aspects of the review. Specifically, GHD reviewed and provided advice on the DSO's capex costs while CEPA reviewed and provided advice on the DSO's proposed opex costs and the Cost of Capital.

The advice put forward by the CRU's consultancy support has informed the proposals outlined in this Draft Determination. In addition, the reports put forward by both CEPA and GHD are published alongside this paper. To avoid repetition, this paper does not reproduce the analysis carried out by CEPA and GHD but focuses on some of the key conclusions. Accordingly, this Draft Determination should be read in conjunction with the CEPA and GHD reports in order to gain a full understanding of all aspects of the review of the DSO's PR6 submissions.

1.1 The CRU's Legislative Remit

Under Section 35 of the Electricity Regulation Act, 1999 ('the Act'), the CRU approves charges for the use of the electricity distribution system in Ireland. An extract from Section 35 is set out below.

> **35** – (1) Subject to *subsection (2)*, within such time as the Commission may direct, the Board shall prepare a statement for the approval of the Commission setting out the basis upon which charges are imposed —
>
> *(a)* for use of the transmission or distribution system of the Board, and
>
> *(b)* for connection to the transmission or distribution system of the Board.
>
> (2) The Commission may give directions to the Board from time to time in respect of the basis for charges for use of and connection to the transmission system or distribution system of the Board.
>
> […]
>
> (4) A charge for connection to or for the use of the transmission or distribution system of the Board shall be calculated in accordance with directions given by the Commission under this section so as to enable the Board to recover— (a) the appropriate proportion of the costs directly or indirectly incurred in carrying out any necessary works, and (b) a reasonable rate of return on the capital represented by such costs.
>
> (5) The Commission, solely, will determine what constitutes an "appropriate proportion" referred to in subsection (4)(a) and a "reasonable rate of return" referred to in subsection (4)(b).
>
> […]
>
> (7) The Commission shall publish the statement referred to in subsection (1).
>
> (8) With a view to increasing transparency in the market and providing all interested parties with all necessary information and decisions or proposals for decisions concerning transmission and distribution tariffs, as referred in Article 60(3) of the 2019 Internal Electricity Market Directive, the Commission shall make publicly available the detailed methodology and underlying costs used for the calculation of the relevant network tariffs, while preserving the confidentiality of commercially sensitive information.

In accordance with Section 35 of the Act, the Draft Determination outlines the CRU's proposals on the revenue that the network companies will be allowed to recover from Use of System customers during the period from 2026 to 2030. In accordance with Section 35(4), these charges are to be calculated to enable recovery of:

- the appropriate proportion of the costs directly or indirectly incurred in carrying out any necessary works; and
- a reasonable rate of return on the capital represented by such costs.

Section 36 of the Act requires the statement of charges, prepared in accordance with Section 35, be submitted to the CRU for approval. The statement of charges will not take effect until approved by the CRU.

In accordance with Section 35(7) of the Act, the TSO's approved statement of charges for each year of PR6 will be published annually by the CRU in August for the upcoming 1st October to 30th September tariff period.

1.2 PR6 Strategy

On 24 April 2024, the CRU published its PR6 Strategy Paper[7]. This paper sets out the CRU's objectives and preferred outcomes for PR6 which are summarised in this section. A summary and review of the responses received to the Strategy Paper can be found in Appendix 2 of this Draft Determination paper.

In recent years, there have been major policy developments at national and European level that have and will continue to drive significant change in the energy sector. The publication of the Climate Action Plan 2024 was the third annual update to the Climate Action Plan 2019 and reaffirmed the challenge ahead for the electricity sector in Ireland. These developments are set out in greater detail in the PR6 Strategy Paper.

PR6 will be a critical price review for network companies to fulfil their role in the delivery of Ireland's decarbonisation and renewable electricity ambitions. It is also important that throughout PR6, network companies continue to provide resilient energy networks and supplies while also ensuring high-quality and secure services to customers and networks users. To achieve this, CRU has set three outcomes that it expects network companies to deliver. Transforming Ireland's electricity networks as part of the energy system transition, presents a significant challenge that requires emphasis on shaping PR6 to be a more outcomes focused price control.

[7] Available here.

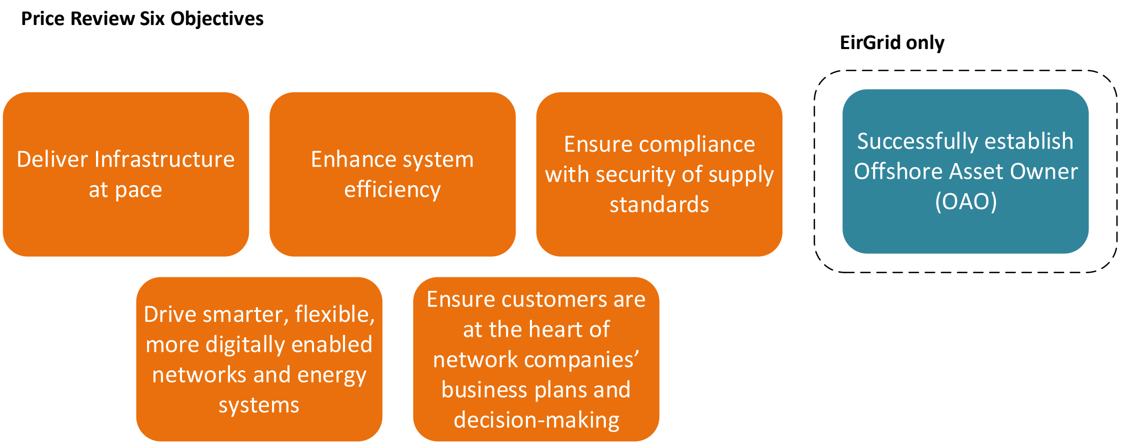
- **Decarbonised electricity:** Network companies must facilitate realisation of Ireland's decarbonisation ambitions, enabling high levels of renewable electricity integration, driving an environmentally sustainable, low carbon energy system.

- **Secure and resilient networks and supplies:** Network companies must ensure safe, secure, resilient electricity networks and supplies which customers can rely on.

- **Empower customers:** Network companies must deliver high quality and reliable services to customers, ensuring their voice is heard and reflected in the work they do, and that the cost of the transition is minimised.

To ensure delivery of these key outcomes, the CRU considers the objectives in Figure 4 to be central to the network companies for PR6.

Figure 4: Price Review Six Objectives



- **Deliver infrastructure at pace** to support decarbonisation, the realisation of Ireland's renewable energy and climate change targets and reducing the cost of constraints to consumers.
- **Enhance system efficiency** while continuing to meet the needs of the network and protecting the long and short-term customer interest.
- **Ensure compliance with security of supply standards** by efficiently managing and developing the networks.
- **Drive smarter, flexible, more digitally enabled networks and energy system** to improve capabilities and ongoing efficiency.
- **Customers at the heart of business planning and decision making.**

- The EirGrid only objective **to Successfully establish Offshore Asset Owner (OAO)** is discussed in a separate Draft Determination published alongside this paper (CRU202589).

1.3 PR5 Outturn Figures

Within this paper, the figures provided by the DSO on their respective expenditure during the PR5 period have been labelled as actual or outturn values. This is not strictly correct. In some cases, the 2024 and 2025 values are the DSO's best estimate of the expenditure they will incur in both years.

The final values for 2024 and 2025 will be reviewed when these are available in 2026 and if necessary, any under or over-recovery from the DUoS customer will be corrected at that time to reflect the actual outturn values through the annual tariffing process.

1.4 Responding to this Paper

Responses to this paper should be returned by email by 17:00 on 11 September 2025 and marked with the reference CRU202587.

Responses by e-mail should be sent to CRU at pricereview6@cru.ie.

Please note the CRU intends to publish all submissions received. Unless marked confidential, all responses may be published on the CRU's website. Respondents may request that their response is kept confidential. The CRU shall respect this request, subject to any obligations to disclose information. Respondents who wish to have their responses remain confidential should clearly mark the document to that effect and include the reasons for confidentiality. Responses from identifiable individuals will be anonymised prior to publication on the CRU website unless the respondent explicitly requests their personal details to be published. Our privacy notice sets out how we protect the privacy rights of individuals and can be found here.

Information on the CRU's role and relevant legislation can be found on the CRU's website at www.CRU.ie.

1.5 How to Navigate This Paper

A high-level summary of the approach the CRU has adopted to determine the proposed revenue that the DSO can recover from DUoS customers during the period 2026 to 2030 is set out below.

The CRU recognises that this is a large paper and covers a range of proposals. To assist the readers, the below summarises the key sections of the paper.

Section 3: Review of Allowed Expenditure between 2021 – 2025

- **Section 3.1: Review of Historic Capital Expenditure**

  The capital expenditure incurred by the network company over the period 2021 to 2025 is reviewed and a summary of key conclusions provided.

- **Section 3.2: Review of Historic Operational Expenditure**

  The opex incurred by the network company over the period 2021 to 2025 is reviewed and a summary of key conclusions provided.

- **Section 3.3: Conclusions and Draft Determination Questions**

Section 4: Review of Forecast Expenditure between 2026 – 2030

- **Section 4.1 Review of Forecast Capital Expenditure**

  The capital expenditure program proposed for the PR6 period, as forecasted by the network company was examined, with particular focus on ensuring value for money and the CRU's PR6 objectives as set out in Section 4.

- **Section 4.2 Review of Forecast Operational Expenditure**

  The opex program proposed for the PR6 period, as forecasted by the network company was examined, with particular focus on ensuring value for money and the CRU's PR6 objectives set out in Section 4.2.

- **Section 4.3: Conclusions and Draft Determination Questions**

Section 5: The Regulatory Asset Base

- Following the above reviews of historic capital expenditure any variances between the approved and actual expenditure which had been efficiently incurred by the network company were reflected by adjusting the regulatory asset base (RAB).
- The RAB was also adjusted to allow for the forecast capital expenditure. This adjusted RAB will be used for the forthcoming review period (2026 to 2030) and is published as part of the CRU's Price Review model, alongside this paper. Key proposals are summarised, and a number of Draft Determination questions are set out.

Section 6: Determining the Proposed Cost of Capital

- A cost of capital to be applied to the network company's regulatory asset base, has been developed and this has been addressed in Section 6 of this paper. Key proposals are summarised, and a number of Draft Determination questions are set out.

Section 6: Financeability

- A summary of the financeability assessment is provided. As noted in Section 7, the CRU must have regard to the ability of network companies to finance their operations.

Section 8: Determining the Proposed Allowed Revenue

- The output of the above steps is then used to develop the proposed allowed revenues for the DSO (which will be recovered from the DUoS customer) for each calendar year within the period 2026 to 2030. This revenue feeds through into the setting of the annual DUoS tariffs, which cover the period 1 October to 30 September.

Section 9: Customer Impact Summary

- The impact of the PR6 distribution Draft Determination proposals, in terms of current estimates of network charges and cost drivers are discussed in this section.

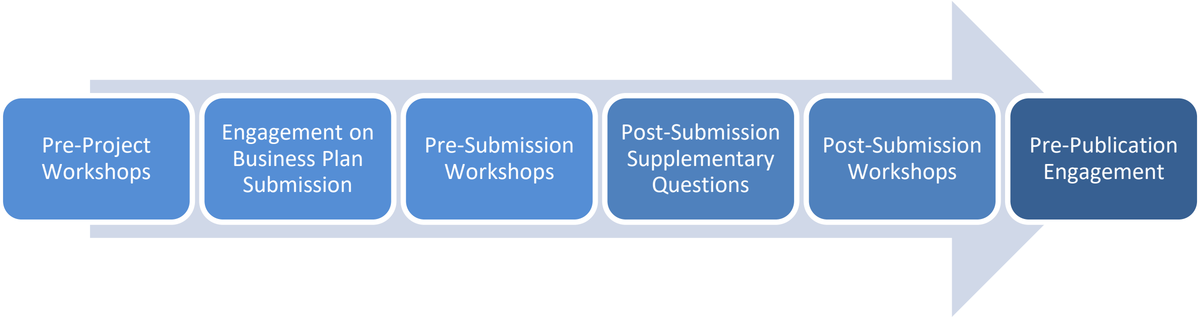
The CRU has assumed that the distribution system operator and owner functions will continue to remain as a commercial semi-state enterprise for the duration of the review and there will be no substantial changes made to its structure although improvements in its independence and governance are expected over the period.

Therefore, the distribution allowed revenues for 2026 to 2030 have been set on the basis of the current industry structure and the CRU is assuming that this structure will be in place for the entire PR6 period. Should this position change, or is likely to change, at some point over the five years of this price review period (2026 to 2030), the CRU will take the appropriate steps to review the regulatory structures and revenues in place.

1.5.1 Conduct of Review

To ensure that the CRU and its advisors attained an adequate understanding of the network companies business plans, the CRU engaged to ensure that the relevant data was provided in a useable format. Figure 5 sets out the CRU's PR6 engagement with network companies prior to the publication of the Draft Determination Paper.

Figure 5: CRU's PR6 Engagement with Network Companies



Engagement for PR6 had some notable changes to PR5. In particular, the CRU began using dedicated supplementary questions to obtain more detailed information on specific queries and set realistic response times for the network companies. There has also been a significant increase in the level of engagement with ESBN, including (but not limited to):

- 10 Workshops on the Business Plan Submissions prior to issuance to ESBN by CRU;
- 14 Information Sessions prior to Business Plan Submissions by ESBN;
- Over 12 Workshops and deep-dive information session post-Business Plan Submissions; and
- *Circa* 500 supplementary questions issued.

The aim of this engagement was to clarify significant points related to each network companies' submissions, and to allow the CRU to seek clarifications to better understand the network companies' justifications. The engagement allowed the CRU, with the assistance of its advisors, to complete a comprehensive review of the network companies historic, forecast and additional information submissions and ultimately lead to the development of the decisions outlined in this paper.

The CRU has updated the licensees on the progress of the Draft Determination and held ad hoc meetings to discuss various topics of concern to each licensee. This included an in-person workshop where the CRU's proposals for the Draft Determination were shared. Prior to the publication of the consultation, both parties were provided with an opportunity to review the documentation for factual accuracy.

Following publication of the Draft Determination, the CRU will establish a structured process for post-draft determination engagement.

1.6 Related Documents

Further background relevant to this paper can be found in the following documents:

CRU	Price Review Six Infographic	CRU202592
CRU	Price Review Six Summary	CRU202586
CRU	Price Review Six Regulatory Framework	CRU202590
CRU	Price Review Six Impact Analysis Note	CRU202591
CRU	DSO Draft Determination Revenue Model	CRU202599i
CEPA	DSO Operational Expenditure Cost Assessment	CRU202599c
GHD	DSO Capital Expenditure Cost Assessment	CRU202599e
GHD	Network Needs Assessment	CRU202597
CEPA	Inflation Trends and Ongoing Efficiency Report	CRU202593
CEPA	PR6 Onshore WACC Paper	CRU202594
CEPA	Financeability	CRU202596

2 Regulatory Framework

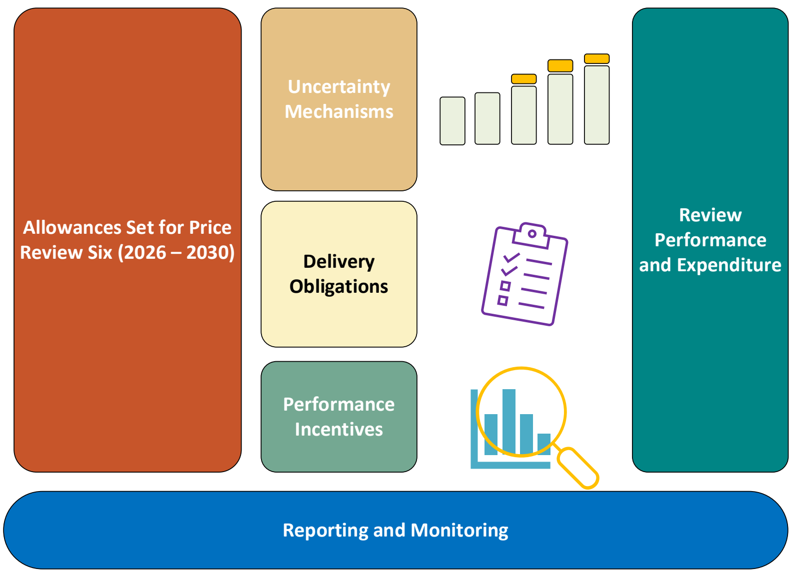
As set out within the PR6 Strategy Paper, the PR6 regulatory framework will represent an evolution of the PR5 framework and will retain several methodologies used in PR1 through to PR5.

The regulatory framework plays a central role in setting clear expectations for the services the network companies must deliver, such as reliability, capacity etc and links their financial returns to performance against these targets. This ensures that network companies are focused on delivering the outcomes that service consumers interests. The framework also promotes efficient investment, innovation and accountability. A clear framework also gives network companies the confidence to invest in infrastructure and tools, knowing they can recover efficient costs through regulated revenues.

2.1 Proposed PR6 Regulatory Framework

The CRU considers that continuing the move to a more outcome-focussed process; providing flexibility within the framework for the network companies and requiring improved performance will facilitate the necessary transformation needed to deliver the ambitious 2030 targets in a sustainable manner minimising the cost for consumers.

Figure 6: Proposed PR6 Regulatory Framework



With this in mind, the CRU is proposing a number of changes to the current regulatory framework. These are summarised below:

- A targeted set of allowances clipped to 37 **Delivery Obligations (DOs)** with remaining allowances flexible across portfolio subject to *ex-post* reviews on meeting required outputs.
- **Enhanced reporting and monitoring**, particularly for the most critical projects, with increased incentives to deliver.
- Clearer mechanisms for tracking changes to milestones and outputs and the associated costs. This is facilitated through the proposed **Agile Investment and Monitoring Framework** (AIMF). This will allow for adaptive and flexible processes (via Volume Drivers and Reopeners) for approving additional funding requests during the period giving companies confidence that contingent allowances above baselines will be available to them.
- An evolved and more targeted set of 27 **Performance Incentives** (PIs).
- **Increased strength of the delivery and performance incentive package** overall, with the introduction of new delivery incentives and re-anchored and sharper performance incentives.

The proposed PR6 Regulatory Framework is set out in greater detail in a paper alongside this Draft Determination (CRU/202590).

3 Review of Allowed Expenditure between 2021 – 2025

This part of the paper sets out the CRU's Draft Determination proposals on the DSO's allowances for PR5 (2021 – 2025), following the historic review of outturn expenditure. The following sections will summarise the:

- Review of historical capital expenditure; and
- Review of historical operational expenditure.

The main objective of the PR5 review is to assess whether expenditure has been incurred efficiently and whether the expected outputs and benefits for customers have been achieved. Consistent with previous price reviews, the following areas were examined in detail:

- Comparing the outturn expenditure (and currently projected for 2024 and 2025) with the allowed expenditure;
- Understanding the differences between allowed expenditure and the outturn expenditure; and
- Assessing cost drivers and their impact on performance.

3.1 Review of Historical Capital Expenditure

This section examines the DSO's capital expenditure over the PR5 period (2021 to 2025). The outturn expenditure is assessed, looking at the output in terms of delivery and efficiency. The DSO's gross outturn capital expenditure in PR5 was €3.72bn, against an allowance of €3.87bn resulting in a €157.2m underspend. Within this overall spend there are significant overspends and underspends against the allowances for several expenditure categories.

A more detailed description and breakdown is provided in the accompanying Advisors' Report (CRU/202599e).

Table 6: DSO's Capital Expenditure Summary over the PR5 Period (2021 to 2025)

Category	PR5 *Ex-ante* Allowance (€m)	PR5 Outturn/Forecast (€m)	PR5 *Ex-post* Allowance (€m)	Varriance(€m)
Gross Capital Expenditure	3,873.4	3,716.2	3,655.8	60.4
Net Capital Expenditure	3,403.4	3,181.5	3,121.0	60.5

Over the PR5 period the DSO reprioritised its capital expenditure toward load-related capital expenditure to accommodate a significantly higher number of new business connections and reinforcements than had been forecasted at the beginning of the PR5 period.

Table 7: Detailed DSO's Capital Expenditure over the PR5 Period (2021 to 2025)

Investment Category	PR5 *Ex-ante* Allowance (€m)	PR5 Outturn/Forecast (€m)	PR5 *Ex-post* Allowance (€m)
Load related Capex	1,638.2	1,651.7	1,623.5
Non-load related Capex	1,856.0	1,634.9	1,578.7
Non-network Capex	379.2	429.6	429.6
Total Gross Capex	**3,873.4**	**3,716.2**	**3,631.8**
Customer Contributions	-251.0	-371.2	-371.2
Customer Contributions Generation Connections	-164.0	-95.0	-95.0
Repayable Line Diversions	-55.0	-46.2	-46.2
FMR Contributions	0.0	-22.4	-22.4
Total Contributions	**-470.0**	**-534.8**	**-534.8**
Total Net Capex	**3,403.4**	**3,181.4**	**3,097.0**

3.1.1 Review of DSO Load Related Capital Expenditure

Electricity load-related capex refers to investment made by the DSO to expand or upgrade the network in response to changes in electricity demand. This includes infrastructure needed to connect new customers, support increased consumption from existing users and/or accommodate emerging technologies such as electric vehicles.

Table 8: Summary of PR5 DSO Load-Related Allowed and Outturn Allowances

Investment Category	PR5 *Ex-ante* Allowance (€m)	PR5 Outturn/Forecast (€m)
New Business	591.2	683.7
Reinforcements	625.1	628.3
Other Load-Related Capex	421.9	339.7
Total	**1,638.2**	**1,651.7**

This section discusses the PR5 allowed and outturn allowances as summarised in Table 8. Overall PR5 load-related capex was close to target in gross terms, the underlying year-on-year swings and the lag in net capex reveal issues in forecasting, timing, and delivery consistency. Customer Contributions helped minimise the impact, but volatility in volume and project timing remains a structural challenge. Costs related to load related capex are classified as:

- **New Business:** this cost category covers new demand connections (G1 - new housing scheme connections; G2 – non-scheme housing connections; and G3 –

commercial/industrial supply connections) and the associated Whole Current Metering (WCM) programme.

- **Reinforcement:** this cost category covers HV reinforcement (including large-scale projects at 110kV and 38kV, and DSO works associated with new 220kV substations); MV/LV system reinforcements and 20kV conversion works.
- **Other Load related**: elements that make up the other load-related capex investment category include new generator connections, repayable and non-repayable line diversions and wayleave payments.

New Business

This section covers two investment categories namely, new demand connections (New Housing Scheme, Non-Scheme Housing and Commercial supplies) and (WCM).

The total gross New Business capex outturn was €683.7m which was an overspend of €92.5m (16%) above the CRU's allowed total (€591.2m). However, the net capex shows an underspend of €27.6m or 8.1%. The overspend was driven by an increase in the number of connections delivered beyond forecast, an increase in average unit costs, material cost increases, a shift in connection mix and complexity of installations. A summary of the key points in the review is set out below:

- As noted above, during PR5 (2021–2025), the DSO was allowed a gross €591.2 m by the CRU for new demand connections, split across G1 (new housing schemes), G2 (non-scheme houses), and G3 (commercial/industrial) including metering. DSO's outturn gross expenditure rose to €683.7 m, exceeding the allowance by €92.5 m (16%). However, customer contributions were significantly higher than predicted (€371.2 m vs. the €251.0 m allowance), causing the net capex figure for new connections result in an underspend of CRU allowance by *circa* €27.8 m (8%).
- The DSO's G1 outturn allowance was €228.4m (13%) higher than the PR5 allowance of €203.0m. This was primarily driven by increased volumes and was offset by high-density scheme efficiencies. G2 outturn spend is 32% higher than the PR5 decision. This reflected rural single build demand and 33kVA transformer shifts. Lastly, G3 outturn was 12% above the PR5 allowance. This was driven again by more connections than forecast, but a slightly lower than average cost per connection. The CRU has deemed that the new demand connections outturn is reasonable.
- The DSO's outturn expenditure on WCM was €30.9m, compared to the CRU's net allowance of €38.8m. Annual expenditures varied from €7.4m in 2021 down to €4.7m in

2023, then rising again to €7.0m in 2025. The annual run rate (expenditure as a percentage of total new connections capex) begins at 6.4% in 2021, falls to 3.6% in 2023, and stabilises at 4.3% in the final two years. The 20% underspend on WCM in PR5 appears to be driven by efficiency gains driven particularly from higher-density developments, better procurement, and the introduction of civil inspectors. We consider therefore the €30.9m WCM capex for PR5 reasonable.

The PR5 outcome highlights the DSO's ability to deliver more connections than planned, albeit at higher gross cost.

Reinforcements

This section covers HV reinforcement, MV/LV System improvements and 20kV conversion works. Overall, the DSO's outturn expenditure was €628.3m against the PR5 allowance of €625.1m. A summary of the key points in the review is set out below:

- The DSO reported a total overspend of €20.7m (7%) relative to the CRU's allowances of €284.9m and an outturn of €305.6m for reinforcement of the HV (110kV and 38kV) network. This was attributed to 168 projects (excluding the flexibility projects), corresponding to the reported outturn expenditure of €305.6m. During the CRU's assessment, the DSO provided an indication of a revised HV reinforcement outturn of €346.5m (a €40.7m increase) to reflect increases in budget costs for 2024 and 2025. However, the DSO did not provide sufficient details on the costs reported per project such that these could be reconciled with the Business Plan submission and, therefore, it is recommended to accept an outturn cost of €277.6m for the projects that could be matched and tracked. Additional supporting information is needed from the DSO to justify the expenditure associated with PR5 HV reinforcements.
- MV/LV System improvements expenditure is not attributable to individual projects but incurred through undertaking reactive interventions. The DSO outturn expenditure was €258.4m relative to the CRU's allowances of €200.3m. This overspend of €58.1m (29%) was driven by MV System Improvement (SI) works which is dominated by the spend for reactive MV works. This is due to a change in accounting for indirect connection costs. Prior to PR5 it is understood that all of the MV SI costs can be deemed to be reactive. As such, the outturn PR5 costs for reactive MV SI appear to be in line with those observed at the end of PR4, and reasonable in view of the explanations provided. In summary, the CRU has deemed the MV/LV System improvements capex reasonable.
- The DSO reported a total underspend of €75.7m (54%) for 20kV conversion in PR5 relative to the CRU allowances (total of €139.9m). The outturn spend of €64.1m includes

€7.4m for interface transformers (IFTs) and €56.8m associated with conversion of the network, principally rural network. Based on our analysis/review and having considered the DSO's submissions, we recommend allowing the full PR5 outturn cost.

In summary, the CRU requires further information to justify the DSO's HV reinforcement outturn spend and will consider additional information provided by the DSO prior to the Final Determination.

Other Load related Expenditure

This section covers generator connections, line diversions (repayable and non-repayable) and wayleave costs. Overall, the DSO reported a gross outturn expenditure of €339.7m against a CRU allowance of €421.9m. This represents an underspend of €82.2m (19.5%). A summary of the key points in the review is set out below:

- The Generator Connections work programme facilitates the connection of renewable generation projects including wind, solar, and hybrid facilities to the distribution network. The CRU allowed €227.7m for generation connections, with the goal of enabling approximately 2.2 GW of new renewable capacity by 2025. However, the DSO outturn expenditure is reported to be €92.5m, reflecting only around 40% of the original allowance. This underinvestment aligns with the shortfall in outturn capacity, which is now projected to reach 1.0 GW rather than the originally anticipated 2.2 GW. Overall, the explanations provided by the DSO for the PR5 outturn are deemed reasonable.
- Line diversions are works on the network to address conflicts with third-party development adjacent to the network. These can relate to development work associated with new demand connections, extension or development activities (often related to agricultural activities). In PR5, the CRU allowed €177.5m for line diversions, divided across non-repayable and repayable categories. The DSO overspent by €69.8m (39%) compared with the CRU allowance. This underscores the uncertainty in forecasting costs for developer-led line relocations, as well as the need to strengthen the way the DSO recovers costs. Overall, the explanations provided by the DSO for the outturn variance in the line diversion expenditure are deemed to be reasonable.

Having reviewed the DSO's submission, notwithstanding the HV reinforcement capex, the CRU considers the associated underspends and overspends reasonable. However, the CRU is concerned that part of the overspend was driven by the DSO being unable to accurately forecast its non-network capital expenditure.

Further analysis of the DSO's load related capex is detailed in our advisor's report and a summary of the DSO's Load Related PR5 capex allowance is set out in Table 9 below.

Table 9: Summary of the DSO's Load-Related PR5 Capex Allowance

Investment Category	PR5 *Ex-ante* Allowance (€m)	PR5 Outturn/Forecast (€m)	PR5 *Ex-post* Allowance (€m)
(G1) New housing Schemes	203.0	228.4	228.4
(G2) Non-scheme Houses	169.1	222.8	222.8
(G3) Commercial/Industrial Supplies	180.2	201.5	201.5
Whole Current Metering	38.9	30.9	30.9
New Business - Subtotal	**591.2**	**683.7**	**683.7**
110kV	160.1	147.0	277.6 – recommended due to lack of clear information about final (revised) outturn cost.
38kV	124.8	158.8	
MVLV System Improvements	200.3	258.4	258.4
IFTs associated with 20kV Conversion	9.5	7.4	7.4
20kV Conversion	130.4	56.8	56.8
Reinforcements – Subtotal	**625.1**	**628.3**	**600.1**
Generation Connections	227.7	92.5	92.5
Non-Repayable Line Diversions	112.7	173.6	173.6
Repayable line diversions	64.8	73.7	73.7
Wayleaves	16.7	0.0[8]	0.0
Other Load-Related – Subtotal	**421.9**	**339.7**	**339.7**
Total Load Related Capex	**1,638.2**	**1,651.7**	**1,623.5**

3.1.2 Review of DSO Non-load Related Capital Expenditure

The Non-load related capex refers to investment in the distribution network that is not directly driven by changes in demand or load growth. Instead, it covers works needed to maintain, replace or upgrade existing assets to ensure ongoing safety, reliability, and compliance. Overall, the DSO reported an outturn of €1.63bn against a CRU allowance of €1.86bn.

[8] Spend captured in other categories. Limited information provided to track expenditure.

Table 10: Summary of PR5 DSO Non-Load Allowed and Outturn Allowances

Investment Category	PR5 *Ex-ante* Allowance (€m)	DSO Outturn/Forecast (€m)
Asset Renewal	540.6	593.1
Continuity Improvement	46.0	48.0
Response capex	31.3	83.5
System Control	199.4	231.6
Smart Metering	1,038.7	678.3
Total	**1,856.0**	**1,634.9**

Summary of costs in this category are classified as;

- **Asset Renewal**: this cost category includes planned programmes of replacement for each of the main asset categories; and
- **Other non-load related investments**: this cost category relates to other investment programmes associated with system (continuity) improvements, reactive fault repairs, system control and smart metering.

Asset renewal programmes

Overall, the DSO's outturn expenditure was €593.1m relative to CRU allowances of €540.6m. This represents an overspend of €52.5m (10%). The largest overspend variances relate to MV overhead lines (€36m), HV cables (€32m) and LV underground renewals (€27m) while the largest underspend variances relate to rural LV overhead lines (€40m), HV overhead lines (€25m) and meters / time switches (€16m). It is evident that there was a significant change in the delivery of PR5 asset renewal capex compared to the original allowances. This was due to a number of reasons, including *inter alia* the rollout of smart meter programme, additional new data from network patrols and re-prioritisation of circuit renewals. In summary, the explanations provided by the DSO for the outturn variances are deemed reasonable.

Other non-load related expenditures

For other non-load related capex, the DSO's outturn expenditure was €1,041.8m relative to CRU allowances of €1,315.4m. This represents an underspend of €273.6m. There are however some notable overspends observed for the response capex and system control categories. A summary of the key points in the review is set out below:

- Overall, the DSO overspent €52.2m (167%) on response capex. This is a reactive work programme, typically driven by third parties or unplanned events. The overspend occurred over 7 work programmes in PR5 mainly driven by meter replacement, time switch replacement and LV cable replacement.

- On continuity, the DSO's outturn for PR5 was €48m compared to the allowance of €46m, representing a €2m increase. Most work programmes do not have costs reported against them providing an uncertainty around the outturn capex for the line items. We recommend that a reduced value (50%) of the outturn capex be accepted in the absence of transparency about the nature of outturn costs.
- The PR5 capex allowance for System Control was €199.4m, but the outturn expenditure reached €231.6m, resulting in an overspend of €32.3m or 16%. This overspend can be mainly attributed to National Network, Local Connections Programme (NN,LC) investment. The DSO did not provide sufficient detail on the breakdown or a robust justification of the additional works and associated costs in PR5. As such, the CRU requires additional information to justify the overspend.
- The deployment of smart meters is a critical component in the transition to a more efficient and cost-effective energy system. Smart metering has several benefits for network customers including more accurate billing and ultimately access to smart electricity tariffs. The DSO reported an underspend of €360.5m (35%) on Smart Metering programme with an outturn of €678.3m capex. This was because of work not delivered and some efficiently incurred savings across several work programmes. The underspend in capex suggests that the PR5 investment request was not as robust as would have been expected. Based on our analysis/review and having considered the DSO's submissions, we recommend allowing the full expenditure set at the PR5 outturn cost.

Having reviewed the DSO's submission, notwithstanding continuity improvement and system control capex, the CRU considers the associated underspends and overspends reasonable.

Further analysis of the DSO's non-load related capex is detailed in our advisor's report and a summary of the proposed allowance is set out in Table 11 below.

Table 11: Summary of the DSO's Non-load Related PR5 Capex allowance

Investment Category	PR5 *Ex-ante* Allowance (€m)	DSO Outturn/Forecast (€m)	PR5 *Ex-post* Allowance (€m)
Renew Prog - 110kV & 38kV Lines	39.1	14.2	14.2
Renew Prog - 110 & 38kV Cables	46.0	78.2	78.2
Renew Prog - HV Substation	145.3	161.9	161.9
Renew Prog - MV Overhead Lines	166.3	202.1	202.1
Renew Prog - MV Cables	0.0	0.0	0.0
Renew Prog - MV Substations	48.8	67.5	67.5

Investment Category	PR5 *Ex-ante* Allowance (€m)	DSO Outturn/Forecast (€m)	PR5 *Ex-post* Allowance (€m)
Renew Prog - Urban LV Renewal	4.7	0.6	0.6
Renew Prog - Rural LV Network	45.7	5.9	5.9
Renew Prog - LV cables and associated items	20.0	46.6	46.6
Meters and Time Switches	23.6	7.9	7.9
Renew Prog - Cutouts	1.1	8.2	8.2
Total Asset Renewal	**540.6**	**593.1**	**593.1**
Continuity Improvement	46.0	48.0	24.0 further information required to provide transparency about the nature of outturn costs
Response capex	31.3	83.5	83.5
System Control	199.4	231.6	199.4 further information required on approval of allowances for additional projects
Smart Metering	1,038.7	678.3	678.3
Total Other Non-load Related	**1,315.4**	**1,041.8**	**985.5**
Total Non-Load Related Capex	**1,856.0**	**1,634.9**	**1,578.7**

3.1.3 Review of DSO Non-network Related Capital Expenditure

This section summarises the DSO's non-network capital expenditure during the PR5 period. The cost items include head office accommodation/vehicles and Distribution Asset Management (support & planning). Overall, the DSO reported an outturn expenditure of €429.6m against the PR5 allowance of €379.2m, representing an overspend of €50.4m (13%).

Head office accommodation/vehicles

This work programme is composed of a range of activities related to property, vehicles, environment, tools and new customer experience. A summary of the key points in the CRU's review is set out below:

- **Property:** This area focuses on enhancing maintenance across all depots to meet requirements, comply with building regulations, and ensure safety. The DSO has reported a total outturn capex for property over the PR5 period of €69.2m, compared to PR5 allowances of €104.1m, representing an underspend of €34.9m (34%). For the PR5 period, most of the allowance related to New Builds and Depot acquisitions (€49.9m), with a further €41.2m relating to Refurbishment of properties, a further €11.8m on Environment, and €1.8m on fixtures and fittings. Based on the PR5 review and having considered the DSO's submissions, the full outturn expenditure is deemed reasonable.

- **Vehicles:** This cost item helps the DSO in its fleet investment programme. The DSO reported an outturn capex of €62.0m against an allowance of €54.6m representing an overspend of €7.4m (14%). The PR5 allowance was exceeded due to an additional 230 vehicles above the original plan. The PR5 investment facilitated the replacement of 553 vehicles due to age, the purchase of 52 additional vehicles for revised work arrangements, and 184 additional vehicles for new technicians (NTs). This resulted in the largest fleet investment programme ever delivered, ensuring a reliable and fit-for-purpose fleet. Based on our analysis/review and having considered the DSO's submissions, the full outturn expenditure is deemed reasonable.
- **Tools:** This work programme aims to provide 'small tools and equipment' and 'larger items of tools and equipment >€7,500'. This includes the replacement of equipment and the provision of new equipment. The DSO reported an outturn of €40.1m against the CRU's allowance of €32.7m. This represents an overspend of €7.4m (23%). The review has noted that the DSO focused on compliance, productivity improvements, and value for money. Based on our analysis/review and having considered the DSO's submissions, the full outturn expenditure is deemed reasonable.
- **Other (Environment and Customer):** For this cost category, the DSO has reported an outturn expenditure of €4.2m against an allowance of €12.1m. This represents an underspend of *circa* 65%. The CRU's PR5 allowance included €8.6m for capital expenditure works at DSO's national wood pole storage facility, Kilteel, and €3.5m for capital expenditure works related to national wood pole storage and disposal management across the country. Since 2023, ESBN has had a persistent IT Delivery Team working on enhancements in the Online Account, so our understanding of both delivery costs and timelines is mature and this feeds into our forecasting in the PR6 submission for the online account. Based on our analysis/review and having considered the DSO's submissions, we recommend allowing the full outturn cost.

Distribution Asset Management (Support and Planning)

This work item is associated with allowances for IT systems, including Corporate IT infrastructure, Enterprise Applications, Distribution Asset Management and Distribution Control / Operation investments.

- The DSO's outturn shows a total Distribution Asset Management spend of €137.5m. This corresponds to a considerable overspend (55%) compared to the allowed capex in PR5 of €88.4m.
- According to the DSO, the overspend was driven by significant changes in the period that led to the reallocation of resources. Some of the identified factors include the impact of the COVID-19 pandemic, industry targets, cybersecurity enhancements and technological advancements.

Based on our analysis/review and having considered the DSO's submissions, we recommend allowing the full outturn costs.

Telecoms

The telecoms work programme comprises of several technologies and solutions to both maintain and expand the telecommunications network connectivity to HV locations. The programme includes provision of connectivity for HV substations, expansion of network capacity, network enhancement and other improvements to improve connectivity across the DSO's sites and assets.

- The total capex spend in PR5 was €78.5m against an allowance of €64.6m. This corresponds to an overspend of €13.8m (21%) across the period. While there has been an overall overspend, several categories of expenditure were under spent due to the COVID-19 pandemic and changes to original proposals for PR5.
- The outturn capex overspend in the PR5 period was driven by the need to upgrade and expand the telecommunications data network to meet evolving operational, cybersecurity, and customer requirements. The CRU is recommending allowing the full expenditure set at the PR5 outturn, however we expect the DSO to transparently report outturn against initial project budget for each of the project agreed with CRU, provide explanations for any significant deviations, and demonstrate prudent management of risk and cost in delivery through suitable reporting.

Having reviewed the DSO's submissions, the CRU considers the associated underspends and overspends reasonable. Further analysis of the DSO's non-load related capex is detailed in our Advisor's Report and a summary of the proposed allowance is set out in Table 12 below.

Table 12: PR5 Summary of the DSO Non-Network Capital Expenditure

Investment Category	PR5 *Ex-ante* Allowance (€m)	DSO Outturn (€m)	PR5 *Ex-post* Allowance (€m)
Head Office Accommodation/vehicles	226.1	213.7	213.7
Distribution Asset Management (Support & Planning)	88.4	137.5	137.5
Enterprise Applications (5 years)	0.0	0.0	0.0
Telecoms	64.6	78.5	78.5
Total Non-Network Capex	**379.2**	**429.6**	**429.6**

3.2 Review of Historic Operational Expenditure

This section examines the DSO's opex over the PR5 period (2021 to 2025). The outturn expenditure is assessed looking at the output in terms of delivery and efficiency. The DSO's total opex in PR5 was €2.03bn against an allowance of €1.96bn resulting in a €71.8m overspend. When controllable and non-controllable opex were assessed independent of each other there was a €123.4m (7.9%) overspend on controllable opex and a €51.5m (12.9%) underspend on non-controllable expenditure. The overall opex overspend (€71.8m) was driven by 'uncertain costs' requested through the annual tariff process.

A more detailed description and breakdown is provided in the accompanying Advisors' Report (CRU/202599c).

Table 13: DSO's Operational Expenditure over the PR5 Period (2021 to 2025)

Category	PR5 Decision (€m)	PR5 Outturn (€m)	Draft Determination (€m)	Variance (€m)
Controllable Opex Total	1,555.5	1,678.9	1,669.2	-9.7
Non-Controllable Opex Total	399.9	348.3	348.3	0
Total Net Opex	**1,955.4**	**2,027.2**	**2,017.5**	**-9.7**

3.2.1 Review of DSO Controllable Operational Expenditure

Table 14 provides a summary of the CRU's opex assessment. Specifically, the table sets out the *ex-ante* opex allowance, the opex outturn costs, and the *ex-post* DSO opex allowance.

Table 14: Detailed DSO's operational expenditure over the PR5 period (2021 to 2025)

Category	*Ex-ante* PR5 Allowance (€m)	PR5 Outturn (€m)	*Ex-post* PR5 Allowance (€m)
System Control	107.2	89.6	89.6

Category	***Ex-ante* PR5 Allowance (€m)**	**PR5 Outturn (€m)**	***Ex-post* PR5 Allowance (€m)**
Planned maintenance	385.5	370.2	370.2
Fault maintenance	243.3	303.1	303.1
Asset Management	97.1	134.6	134.6
Forestry & Wayleaves	28.9	15.6	15.6
Meter Reading	34.6	48.7	48.7
QH Data	11.4	10.5	10.5
Data Aggregation	40.2	35.8	35.8
Customer Meter Operation	15.6	4.7	4.7
Keypad / Token Meter	2.1	1.1	1.1
Smart Metering	69.4	68.8	68.8
Call Centre	38.1	43.9	43.9
Area Operations	65.3	67.4	67.4
Customer Relations	41.9	65.1	65.1
DUos Billing & Accounts Receivable	4.2	3.9	3.9
MRSO	11.3	8.4	8.4
Market Opening / Market Opening IT	61.7	59.2	59.2
Transaction charges	0.0	0.0	-
3rd party damages	0.0	36.4	-
Supply repayable	0.0	0.0	-
Other inter ESB	0.0	8.0	-
Other external repayable	0.0	0.1	-
Other commercial	0.0	15.7	-
Sustainability	0.0	0.0	-
R&D (Innovation)	23.6	22.5	22.5
Company Wide Costs	0.0	7.2	7.2
Corporate Charges & Corporate Affairs	71.6	69.3	69.3
Insurance	32.2	34.6	34.6
Legal	19.1	18.5	18.5
Pension	7.5	10.4	10.4
Environmental	32.8	30.3	30.3
Misc.	0.0	-0.4	-0.4
Health & Safety	46.8	44.1	44.1
Telecoms	35.9	28.3	28.3
IT Opex	0.0	3.8	3.8

Category	*Ex-ante* PR5 Allowance (€m)	PR5 Outturn (€m)	*Ex-post* PR5 Allowance (€m)
DMSO Flex	0.0	9.6	9.6
Other	0.0	0.0	0.0
Contract and Vendor Management	0.0	0.0	0.0
Misc. non-regulatory	0.0	9.7	0.0
DSO Transformation	28.2	0.0	0.0
Total Controllable Opex	**1,555.5**	**1,678.9**	**1,669.2**
Network Rates	387.0	324.0	324.0
CER/CRU Levy	12.9	24.4	24.4
Total Non-Controllable Opex	**399.9**	**348.3**	**348.3**
Total Gross Opex	**1,955.4**	**2,027.2**	**2,017.5**
Telecoms SLA Income	-	-	-
Other Miscellaneous Income	-	-	-
Total Net Opex	**1,955.4**	**2,027.2**	**2,017.5**

There are a number of key points to note that have driven the underspends and the overspends highlighted in Table 14. These are summarised below.

Fault Maintenance

Fault Maintenance refers to reactionary, unplanned activities to respond and repair faults on the network, including response to storms. Fault Maintenance costs are split across four subcategories, three of which are based on the maintenance activities at the different network voltage levels, with the final Storm subcategory referring to faults on all categories of network explicitly caused by storms.

- On an aggregate basis, we note a €303.1m (24.6%) overspend against the Fault Maintenance allowance of €243.3m. Over the PR5 period the DSO saw increased faults due to storms driving significant overspends against the Fault Maintenance allowance, in addition to the wider impact of increasing MV/LV network, increased customer numbers and system demand. Storm expenditure spiked at €17.7m in 2024 in response to Storms Isha and Jocelyn, which had combined restoration costs of €14.7m.
- It is important to consider that while the relationship between Planned Maintenance activities such as timber cutting and Fault Maintenance is not a direct one, there does exist a probabilistic relationship i.e. less timber cutting increases the likelihood that an adverse weather event would result in a fault. The CRU therefore considers that there is a risk of under-delivery of Planned Maintenance activities driving potentially higher than

anticipated outturn expenditure on Storms. Additionally, Planned Maintenance is typically less costly than equivalent, unplanned Fault Maintenance activities, and is also less disruptive to customers. It is important to stress therefore that effective delivery of Planned Maintenance activities by the DSO, rather than reactive Fault Maintenance, may result in lower overall costs, and disruption, for customers.

The CRU has deemed the overspend against Fault Maintenance allowances to be reasonable and recognise factors such as the increasing length and scale of the Irish overhead system versus the underground system and the increasing impact that wind and weather events are having on the system.

Meter Reading

Meter Reading falls under the DSO's Retail Meter Services, and this function is responsible for the collection and processing of customer meter readings.

- The DSO's PR5 outturn for Meter Reading was €48.7m, which compared to an allowance of €34.6m, represents a total overspend of €14.1m (40.9%). This was driven by higher costs associated with new meter reading contracts, and more manual meter reading than originally anticipated (because of delays to smart meter rollout).

- The DSO noted some of the key investments over PR5, including the introduction of a customer portal, which provides escalated support to the DSO's customer contact centre on more complex consumption and smart metering-based customer queries, and Temetra, a cloud-based manual read management application. The DSO claims that this application has improved processes for applying credits/debits to customers and that suppliers are seeing the benefits of this, as it allows for complete registration and change of legal entity on actual reads rather than estimates, reducing bill shock for customers.

The CRU has deemed the overspend on Meter Reading to be reasonable and acknowledge factors which have driven the higher than expected spend, particularly around COVID-19 and the broader technology/telecommunications issues with some devices that has impacted the smart meter rollout.

Planned Maintenance

Planned Maintenance refers to scheduled activities to improve the resilience of the distribution networks and includes High Voltage, Overhead (inclusive of timber), Underground and System Protection and Earthing maintenance costs.

- On an aggregate basis, the DSO underspent Planned Maintenance allowances in PR5 by €15.3m, or 4.0%. However, there were over and underspends against some of the sub cost categories. For example, there was an underspend of €7.8m in High Voltage maintenance and €17.0m in non-timber overheads, while there was an overspend of €9.0m in timber overhead.

- For timber related overhead Planned Maintenance, the DSO provided evidence to explain some of the key drivers for the significant underspends across the sub cost categories, which includes challenges associated with the limited contracting pool. The DSO stated that due to the relatively small pool of available contractors at the beginning of PR5, they had to refocus the timber cutting approach and reprioritise different programmes of work.

- The DSO also highlighted in support of its outturn performance, that the industry has had to increase prices to retain existing contractors, and conduct additional tendering processes to try and attract new market entrants. Existing contractors informed the DSO that the rates were not ‘market-facing’. The DSO, in response, raised rates after conducting market research with UK DNOs. The DSO also cites prices of construction materials used by contractors increasing, driving material costs of operations further, although the CRU notes that this was not quantified as part of the DSO’s submission.

- To mitigate the impact of some of these challenges, the DSO explained that it sought efficiencies and cost savings through the increased use of data analytics to prioritise vegetation management based on operational and safety data. This led to a focus on targeted trimming, pruning and removal in prioritised areas, reducing the scope to essential interventions. The DSO also invested in training for staff on the use of these new digital tools, and carried out various innovative trials such as the use of drones and satellite imagery.

Based on our analysis and having considered the DSO’s submissions, the CRU has deemed the underspend against Planned Maintenance to be reasonable although would note concerns around under delivery of workload volumes across business-critical work programmes, such as timber cutting and this impact this may have on overall network resilience and Fault Maintenance expenditure.

Customer Relations

Customer Relations cost category includes operations and activities associated with new connections, support centre, and customer experience in general.

- The DSO's outturn expenditure for Customer Relations is €65.1m which represents a total overspend of 55.3% against an allowance of €41.9m. The largest overspend was reported in the Scheduling Support Centre category, the function which schedules meter work orders across DSOs' fleet of technicians. This was largely driven by the need to upgrade the existing Click Schedule application, as the existing software reached end of life in December 2023.

- Another area of material overspend was in Customer Awareness (€16.2m spend against €11.2m allowance) which the DSO explains as being driven by increased severe weather events during PR5, and a corresponding increased presence and communication around outages with customers. In response, the DSO increased their social media presence, and headcount in the marketing team. Similarly, the Customer Needs overspend was driven by an increase in customer research (including into smart metering and NN,LC attitudes), an increase in brand and advertising tracking from quarterly to continuously.

The CRU deems the overspend to be reasonable, recognising that many of the activities were driven by factors outside of the DSO's control during some of the more recent storms.

Customer Meter Operation

Customer Meter Operation, which is also referred to as Metering Asset Management within the DSO's submissions, includes costs for activities associated with maintaining the condition of meters, addressing the most significant risks of meter failure, and loss of meter data.

- The DSO's PR5 outturn for Customer Meter Operation was €4.7m, compared to an allowance of €15.6m, representing a total underspend of €10.8m (69.5%).

- The DSO stated that they had scaled up their Major Meter Testing programme, which involves testing high voltage customers. The COVID-19 pandemic meant that some customer installations were unable to be progressed. The DSO also stated that it is on target to meet the volumes set out in its PR5 *ex-ante* assessment and in 2025 there will be a renewed focus on programmes which can give customers a reliable metering solution.

Based on the information provided the CRU deem the underspend to be reasonable and recognise the impact that the COVID-19 pandemic might have had on outturn performance.

Miscellaneous Non-Regulatory

The DSO states that the outturn incurred as miscellaneous non-regulatory outturn, €9.7m, does not tie into its regulatory amounts and is included for information purposes. There was no *ex-ante* allowance set for this category. As the CRU did not receive an explanation for this expenditure to determine whether it is justified and efficiently incurred, we have set the PR5 *ex-post* allowance at €0.0m. More information is needed to explain and justify this expenditure.

3.3 Conclusions

Overall, in PR5 the gross DSO opex outturn was €1.68bn against the allowance of €1.56bn. For the DSO's gross capex outturn was €3.72bn against PR5 allowed revenue of €3.87bn with non-load related capex driving the underspend (11% for this category). The CRU notes the following.

- The DSO experienced success in PR5, especially within the New Connections and Renewable Connections work programmes.
- The DSO faced delivery challenges on other areas. Examples of this can be seen in the reinforcement category, where the LV system improvement and 20kV Conversion programme works significantly underdelivered over PR5.
- The DSO has not provided sufficient information on the underspend and overspend of some cost categories to assess efficiency of delivery.

Question(s):

1. What are your views on the DSO's PR5 outturn capex, and the CRU's proposed Draft Determination ex post PR5 capex allowance?
2. What are your views on the DSO's PR5 outturn opex, and the CRU proposed Draft Determination ex post PR5 opex allowance?
3. Do you have any comments or views on any of the proposals set out in this Section?

4 Review of Forecast Expenditure between 2026 – 2030

This part of the paper sets out the CRU's Draft Determination proposals on the DSO's forecast allowances for PR6 (2026 – 2030). The following sections will summarise the:

- Review of Forecast Capital Expenditure; and
- Review of Forecast Operational Expenditure.

The objective of the forecast review is to set the DSO allowances at an efficient level that allows the DSO carry out its functions and to ensure consumer interest is protected. In addition, given the transformational change that is expected over PR6 and beyond, the CRU has also considered step changes and new activities that may be required from the DSO in order deliver secure, reliable and resilient networks and supplies. The submitted cost requests are reviewed based on the need for, additionality and cost efficiency in the step changes.

1. **Need**: Is there clear evidence that there is expected to be a change in the activities or costs incurred by the network company and has the change been clearly mapped to the business plan questionnaire (BPQ)?

2. **Additionality**: Has it been clearly demonstrated that the costs associated with the proposed step-change are additional relative to the base level?

3. **Cost Efficiency**: Has it been clearly demonstrated that the costs associated with the step-change are efficient? Have other options been explored that could achieve the same outcome? What metrics have been used to test that the requested costs are efficient?

It should be noted that the DSO has put forward a baseline capex proposal, that is presented in its submission on an annual basis. This figure has been put forward to account for uncertainty related to external factors (customer requirements, external dependencies, etc), as well as constraints on delivery of the full programme. In addition to the baseline, ESBN has put forward additional costs required to deliver against the 2030 targets and objectives. This corresponds to the 'High' cost forecast for PR6 set out in this paper.

For further detail please see the accompanying Advisors' Reports (CRU202599e and CRU202599c) published alongside this paper.

4.1 Forecast Capital Expenditure

This section provides the CRU's position on the various capex items over the PR6 period (2026-2030). The review of the PR6 capex programme submitted by the DSO aims to ensure that the expenditure is necessary and represents value for money for the consumer. Table 15 below summarises the PR5 outturn expenditure, PR6 baseline and high requests put forward by the DSO, and the CRU's Draft Determination. As stated above, the high allowances represent the total revenues that can be sought through the CRU's proposed AIMF for PR6 (see CRU202590).

A more detailed description and breakdown is provided in the accompanying Advisors' Report (CRU202599e).

Table 15: Summary of Capital Expenditure Items over the PR6 Period (2026-2030)

Category	PR5 Outturn (€m)	DSO PR6 Request (€m)		PR6 Draft Determination (€m)	
		Baseline	High	Baseline	High
Load Related: New Business	683.7	921.4	921.4	797.0	911.8
Load Related: Reinforcements	628.3	2,207.9	2,714.2	1,816.0	2,585.3
Load Related: Generator Connections	92.5	338.5	369.6	198.7	369.5
Load Related: Other	247.2	343.5	343.5	287.9	315.5
Non-Load Related	1,634.9	2,019.5	2,357.0	1,424.7	2,131.0
Non-Network Related	429.6	786.8	786.8	670.6	690.3
Total Capex (Gross)	**3,716.2**	**6,617.7**	**7,492.5**	**5,194.9**	**7,003.4**
Customer Contributions	-534.8	-762.1	-762.1	-650.9	-879.2
Total Capex (Net of Contributions)	**3,181.4**	**5,855.6**	**6,730.5**	**4,544.0**	**6,124.2**

The DSO requested a total capital expenditure (net) allowance of €6.73bn under the high scenario for the PR6 period representing a 112% (€3.55bn) increase on the DSO's PR5 outturn expenditure of €3.18bn. The DSO is proposing to improve reliability and resilience of the distribution network through a substantial asset renewal programme (€1.1bn) and a network reinforcement program (€2.7bn) to provide additional substation capacity and uprate the network. The DSO is also requesting an increased allowance associated with connecting homes, farms and businesses across Ireland. The following cost categories represent 68.5% (€5,122.5m) of the total gross capex requested by the DSO:

- **Load Related Reinforcements**

  The DSO has requested a total of €2,714.2m for load related reinforcement capex against a PR5 outturn of €628.3m. This represents a 332% increase over the PR5 outturn. There are substantial increases across all of the sub-categories. The increases are dominated by 110kV reinforcement projects and 20kV conversion activities.

- **Asset Renewals**

  The DSO has requested a total €1,106.1m for asset renewal capex against a PR5 outturn of €593.1m. This represents an 86% increase, which is driven primarily by increases across categories including for renewal of HV substations, MV overhead lines, urban and rural LV network, as well as replacement of meters and time switches.

- **New Demand Connections**

  The DSO has requested €868.2m in PR6 for new demand connections (excluding whole current metering) which is an increase of 33% over PR5's outturn of €652.8m. This is driven largely by the projected step-change in forecasted New Housing Scheme (G1) connections under the "Housing for All" strategy and the Non-Scheme Housing (G2) connections.

- **Head Office Accommodation/vehicles**

  The DSO has requested a total €434.0m for head office accommodation against a PR5 outturn of €213.7m. This represents an 103% increase.

Following the review of the DSO's submission, the CRU is proposing a baseline gross capex allowance of €5.2bn. This is an increase of (40%) compared to the DSO's outturn, but €1.4bn less (21%) than the baseline gross capex that the DSO is requesting. Furthermore, the CRU proposes to provide access to additional funding up to a total allowance of €7.0bn during the period through the proposed uncertainty mechanisms.

4.1.1 Review of DSO Load Related Capital Expenditure

The CRU is proposing a load related capital expenditure of €3.10bn for PR6 against the DSO's baseline request of €3.81bn. This represents an 88% (€1.45bn) increase compared to PR5 outturn. In broad terms, this allowance covers expenditure for new business (primarily new demand connections), reinforcements and generator connections. A summary of the load related capex is presented in Table 16 below. Access to additional allowances, indicated by the "High" case in the table, can be achieved through a range of mechanisms detailed in the AIMF (CRU202590).

Table 16: Summary of PR6 Requested Load-Related Capex

	Baseline	High	Baseline	High
New Business	921.4	921.4	797.0	911.8
Reinforcements	2,207.9	2,714.2	1,816.0	2,585.3
Generator Connections	338.5	369.6	198.7	369.5
Other Load-related Capex	343.5	343.5	287.9	315.5
Total Load Related Capex	**3,811.4**	**4,348.8**	**3,099.6**	**4,182.1**

New Business

This cost category is composed of new demand connections and whole current metering. The DSO is requesting €868.2m for new demand connections representing a €215.4m (33%) increase when compared to the PR5 outturn, largely linked to anticipated surges in domestic connection volumes (G1 and G2). The increase is attributed to the projected growth and continued momentum under national housing policies, particularly the "Housing for All" strategy, which is expected to support a sustained pipeline of high-density developments such as apartment blocks and estates. In PR5, the DSO delivered 132,369 new housing scheme connections at a total cost of €228.4m. For PR6, the DSO forecasts a significant increase in connections with a total capex of €358.6 m.

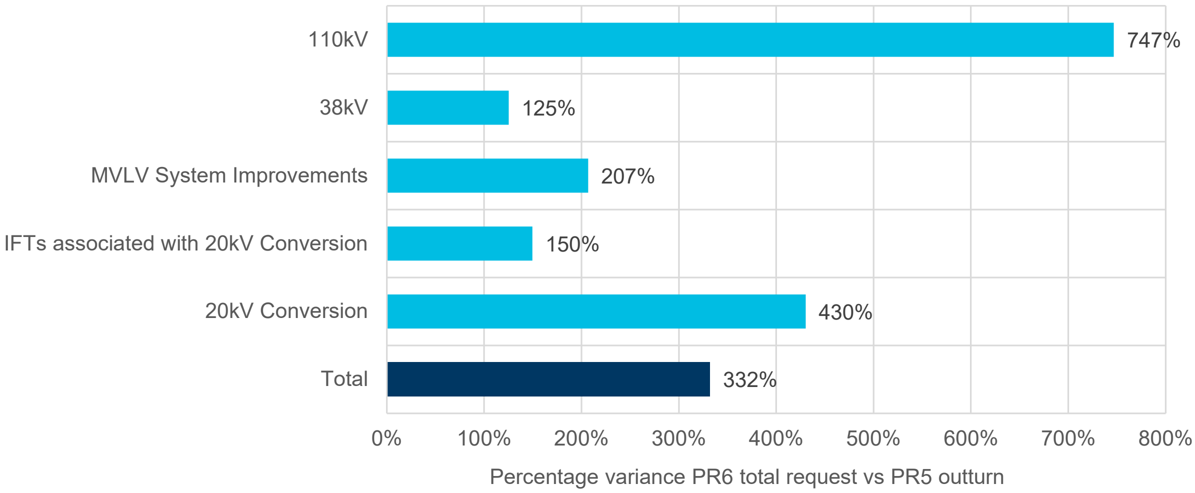
The CRU is proposing to adopt a mid-point volume of connections for the baseline allowance and has accepted the DSO's unit costs assumptions. The DSO has sufficiently demonstrated synergy from high-density builds, standardised pole-mounted transformers, and refined installation processes. New connections are also suitable for the CRU's proposed Volume Driver mechanism enabling the DSO to scale the capex allowance in proportion to actual demand connections that materialise. This is particularly important if volume growth exceeds the baseline.

As noted in the accompanying GHD assessment (CRU202599e), by balancing the approaches above, the PR6 new demand connections can be funded in a manner that aligns with Ireland's current housing and commercial expansion goals whilst also accounting for uncertainty associated with volume growth. In summary, the CRU proposes €759.0m as the new demand connection baseline allowance for PR6, with access to additional allowances as and when the need materialises. This baseline allowance represents a 16% (€106.4m) increase compared to PR5 outturn.

Reinforcement

This cost category covers HV reinforcement, MV/LV System improvements and 20kV conversion works. The DSO is requesting a total of €2,714.2m for load related reinforcement capex which represents a €2,085.9m (332%) increase when compared to the PR5 outturn value of €628.3m. There are substantial increases across all reinforcement sub-categories (See Figure 7). Significant increases in 110kV reinforcement projects and 20kV conversion activity is driven by a portfolio of PR6 projects identified to ensure compliance with system security standards, including PR5 carryover.

Figure 7: Percentage Variance of PR6 Total Request vs PR5 Outturn



The HV programme has been assessed as being required to support the DSO's current planning and security standards and the CRU has concluded that the need for reinforcement of the HV network is justified, and also acknowledges the challenge in overcoming constraints on delivery. HV reinforcement projects have been considered in 3 distinct groups; key projects (31 projects comprising 27 new 110kV stations and 4 projects for DSO works associated with new 220kV stations), other 110kV reinforcement projects (49 remaining 110kV projects) and 38kV projects (90 projects).

- For the key projects, the CRU proposes to set a full allowance (€823.8m), in line with the total request, with an associated delivery obligation to deliver the additional capacity in line with the project plans for these projects (including milestone dates to be confirmed as part of the FD, but allowing for some flexibility in the precise outputs to be delivered to provide the additional capacity using alternative solutions).
- In the case of the 'other 110kV reinforcement projects' group, the CRU proposes to set a reduced baseline allowance of €252.4m, which means that a substantial total baseline

allowance is recommended for 110kV projects (€1,076.2m). This baseline allowance is reduced compared with the total request of €1,244.5m, but substantially increased compared with the PR5 outturn of €147.0m. The approach to setting the baseline allowance represents a reasonable balance between enabling ambitious proposals and limiting deliverability risk on consumers.

- For 38kV projects, CRU proposes to provide a baseline allowance of €173.7m, in line with the baseline request for this category, and compared with a total request of €357.6m.

In addition to the HV reinforcement detailed above, reinforcement of the MV (10kV and 20kV) and LV networks, and conversion of sections of network from operating at 10kV to 20kV, are also included in the Capex proposals:

- For MV/LV reinforcement the DSO has requested a PR6 allowance of €792.6m, an increase of €534.3m (207%) on the PR5 outturn spend. This capex cost category is largely driven by new customer connections. New connection volumes are expected to further increase over PR6 due to electrification and Climate Action Plan targets which increases demand, requiring greater volumes of MV/LV SI to meet the capacity requirements. Reactive LV SI is also expected to cover network improvements relating to the uptake of LCTs, with each LV programme proposing the number of LCT-ready customers expected by the end of PR6. The Draft Determination recommends a baseline allowance of €395.5m against €792.6m requested by the DSO. There is need for more information on cost increases associated with the reactive LV SI elements associated with new connections to clearly align this information with the substantial overall allowance requested.
- In relation to the 20kV conversion programme, the DSO requested €319.5m, an increase of €255.3m (398%) on the PR5 outturn. The programme delivers network benefits in terms of reinforcement and the facilitation of load growth. However, it has historically under-delivered on volumes. The proposed programme for PR6 aims to replace 9,000km of 10kV network. Given the need for additional narrative for transformers and the increased unit cost and volume requested, the CRU is proposing a Draft Determination baseline allowance of €170.8m.

Generator Connections

This programme facilitates the connection of renewable generation projects including wind, solar, and hybrid facilities to the distribution network. The DSO is requesting a substantial increase in the allowance for generator connection costs from €92.5m outturn in PR5 to a €369.6m baseline request for PR6. The main driver for the request is the ongoing policy support for renewables and the maturing Enduring Connection Policy (ECP). The PR5 underspend indicates the uncertainty faced by the DSO related to this cost category.

Given the significant jump and DSO ambition to deliver on the forecasted volumes, we propose to adopt a baseline allowance reflective of a moderate volume of generator connections, releasing further allowances through a reopener when there is clear evidence (e.g., advanced project milestones) that developers are ready. We therefore propose €198.7m as a baseline allowance for PR6.

Other Load-related Capex

The CRU is proposing a €287.9m allowance for other load-related capital expenditure (excluding generator connections) against the DSO total request of €343.5m. The DSO request represents a 39% increase from the PR5 outturn of €247.2m. During our assessment we noted an overspend in non-repayable line diversion costs and we are therefore recommending adopting a volume-driver mechanism and monitoring during the period to avoid sizable overspends without robust evidence of external demand for non-repayable line diversions. A detailed breakdown of our cost assessment is set out in the table below:

Table 17: DSO PR6 Load-Related Request Capex Summary and Revised Allowance

		DSO Request (€m)		Draft Determination (€m)	
Cost Categories	**PR5 Outturn (€m)**	**Baseline**	**High**	**Baseline**	**High**
(G1) New housing Schemes	228.4	358.6	358.6	295.7	358.7
(G2) Non-scheme Houses	222.8	318.8	318.8	272.5	318.8
(G3) Commercial/Industrial Supplies	201.5	190.8	190.8	190.8	190.8
Whole Current Metering	30.9	53.2	53.2	38.0	43.5
New Business Total	**683.7**	**921.4**	**921.4**	**797.0**	**911.8**
110kV	147.0	933.8	1,244.5	1,076.2	1,244.3
38kV	158.8	173.8	357.6	173.7	357.6
MVLV System Improvements	258.4	792.6	792.6	395.3	746.8
IFTs associated with 20kV Conversion	7.4	18.3	18.3	11.2	15.0
20kV Conversion	56.8	289.4	301.2	159.6	221.6
Reinforcements Total	**628.3**	**2,207.9**	**2,714.2**	**1,816.0**	**2,585.3**
Generation Connections	92.5	338.5	369.6	198.7	369.5
Non-Repayable Line Diversions	173.6	209.8	209.8	182.2	209.8
Repayable line diversions	73.7	98.4	98.4	85.7	85.7

		DSO Request (€m)		Draft Determination (€m)	
Cost Categories	PR5 Outturn (€m)	Baseline	High	Baseline	High
Wayleave payments	0.0[9]	35.3	35.3	20.0	20.0
Other Load Subtotal	**339.7**	**682.1**	**713.2**	**486.6**	**685.0**
Total	**1,651.7**	**3,811.4**	**4,348.8**	**3,099.6**	**4,182.1**

4.1.2 Review of DSO Non-load Related Capital Expenditure

The CRU is proposing a €1.42bn baseline allowance for the non-load related capital expenditure against the DSO's request of €2.36bn. The DSO is requesting a total of €1.11bn for asset renewal programmes against an outturn of €0.59bn in PR5, this represents an increase of €0.51bn (86%). This is driven by the DSO's Rural LV Network renewal program which has a requested increase of 725% compared to the PR5 outturn. A summary of non-load related capex is presented in Table 18 below. As noted previously, access to additional allowances, indicated by the "High" case in the table, can be achieved from a range of mechanisms detailed in the AIMF.

Table 18: DSO PR6 Non-Load Related Request Capex Summary

Capex Cost Category	PR6 Request (€m)		Draft Determination (€m)	
	Baseline	High	Baseline	High
Asset Renewal Programme	936.5	1,106.1	629.4	916.3
Continuity Improvement	60.6	60.6	35.9	60.5
Response capex	29.8	29.8	16.1	16.1
System Control	343.3	373.3	255.6	350.8
Smart Metering	649.1	787.1	487.7	787.3
Total Non-load Related Capex	**2,019.5**	**2,357.0**	**1,424.7**	**2,131.0**

Asset Renewal Programme

This work programme is associated with the planned programmes for replacement for each of the main asset categories. These are briefly discussed below.

- For HV substations, the DSO is requesting a total PR6 allowance of €349.7m. This represents an increase of €161.9m (116%) compared with the PR5 outturn. In the detailed assessment of the cost items, it is noted that there are several sub-programmes

[9] Spend captured in other categories.

where additional information (costs and units) is needed to support the request being made. As such, the CRU is proposing a baseline allowance of €197.5m with a reopener to provide access to additional allowances justified during the period.

- For MV overhead lines, the DSO is requesting a total PR6 allowance of €428.2m against a PR5 outturn of €202.2m, which represents a 112% increase. In our detailed assessment we noted that a majority of the sub-programmes identified under this cost category have been justified, however, there is uncertainty around volumes and further detail is required to determine the correct unit costs. The CRU therefore proposes an allowance of €244.4m. Volume drivers will be used to deliver condition assessment (asset patrol) and follow on works for nearly 460k MV poles in rural locations, and clearance of approximately 19.5k defects on the MV network. Also, the DSO will be required to deliver the health index improvements identified in its Business Plan as part of the delivery obligation framework tool for the Pole Inventory Asset Management (PIAM) sub-programme.
- For the MV Substations, the DSO is requesting a total PR6 allowance of €43.5m. The request represents a 36% decrease on the PR5 outturn of €67.5m. There were several programmes under this cost item that did not have sufficient detail in terms of costs and volumes to support the proposals. The CRU is therefore proposing an allowance of €19.7m. This allowance includes €16.8m for 'Replacement of Magnefix Cast-Resin Type Switchgear', which is proposed to be completed under a volume driver with reference to an allowed unit cost and baseline volume to replace 250 units.
- For the Rural LV network, the DSO is requesting a total PR6 allowance of €48.7m against a PR5 outturn of €5.9m representing a 725% increase on the PR5 outturn. Parts of this work programme aims to deliver discrete volumes of work, and therefore the spend will be attributed to the volumes delivered in the case of condition assessment and follow on, LV defect clearance and LV overhead line (OHL) wood pole replacement. The CRU proposes an allowance of €39.8m, with the ability for the DSO to "flex up" the baseline allowances for the volume driven sub-programmes.
- For Overhead lines (110kV & 38kV), the DSO is requesting a PR6 allowance of €64.5m against a PR5 outturn of €14.2m. This represents a 355% increase on the PR5 outturn. The CRU proposes an allowance of €32.7m to provide for progression of activities across the variety of sub-programmes (including completion of PR5 carryover projects and initial work on new circuits identified for interventions in PR6). Further detail is required on unit costs and volumes that would constitute a robust business case for consideration as part of the FD.

Other Non-load related Capex

This cost category covers continuity improvement, response capex, system control and smart metering. The primary cost drivers for other non-load related capex are system control and smart metering. The Draft Determination review and proposals are summarised below:

- For system control, the DSO is requesting a total PR6 allowance of €373.4m. This represents a 61% increase compared to PR5 outturn. The DSO has requested this to put in place the system control infrastructure it considers necessary to deliver the PR6 objective of transformative change and meet the needs of the Climate Action Plan and Clean Energy Package in terms of demand side flexibility, community energy, renewables penetration and reducing renewables curtailment. The CRU notes the uncertainty in the requests made for the programme, which were not considered sufficiently justified. The CRU is recommending a PR6 allowance of €255.6m, with additional allowances available through the AIMF.
- For smart metering, the DSO is requesting a total PR6 allowance of €787.1m. This request aims to support the ongoing development and maintenance of the smart metering infrastructure. Key activities include the installation and replacement of smart meters, the enhancement of communication networks, and the development of advanced metering infrastructure (AMI) systems. For the volume-driven activities associated with installing and replacing smart meters, a baseline volume and associated unit cost is proposed based on the supplementary information provided by the DSO. The review identified a number of discrepancies between submissions for the capex for enhancement of the infrastructure associated with smart metering. Acknowledging this, and the uncertainty around the precise outputs, the CRU proposes to apply reduced baseline allowances with reopeners for these initiatives. As such, the CRU proposes a total PR6 baseline allowance of €487.7m.

The Table 19 below presents summary of the non-load related capex and Draft Determination proposals.

Table 19: Summary of Total PR6 Non-Load Related Capex

Category	PR5 Outturn (€m)	DSO Request (€m)		Draft Determination (€m)	
		Baseline	High	Baseline	High
Renew Prog - 110kV & 38kV Lines	14.2	64.5	64.5	32.9	32.9
Renew Prog - 110 & 38kV Cables	78.2	72.2	79.2	29.0	72.8
Renew Prog - HV Substation	161.9	305.2	349.7	197.5	252.2

Category	PR5 Outturn (€m)	DSO Request (€m)		Draft Determination (€m)	
		Baseline	High	Baseline	High
Renew Prog - MV Overhead Lines	202.1	335.2	428.2	244.4	423.1
Renew Prog - MV Substations	67.5	43.5	43.5	19.8	19.8
Renew Prog - Urban LV Renewal	0.6	6.1	6.1	6.1	6.1
Renew Prog - Rural LV Network	5.9	41.7	48.7	40.1	46.8
Renew Prog - LV cables and associated items	46.6	25.1	25.1	24.9	24.9
Meters and Time Switches	7.9	42.2	60.2	33.7	36.7
Renew Prog – Cutouts	8.2	0.9	0.9	0.9	0.9
Total Asset Renewal Allowance	**593.1**	**936.5**	**1,106.1**	**629.4**	**916.3**
Continuity Improvement	48.0	60.6	60.6	35.9	60.6
Response capex	83.5	29.8	29.8	16.1	16.1
System Control	231.6	343.3	373.4	255.6	350.8
Smart Metering	678.3	649.1	787.1	487.7	787.3
Total Other Non-load Allowance	**1,041.8**	**1,082.9**	**1,250.9**	**795.3**	**1,214.7**
Total Non-load related Capex	**1,634.9**	**2,019.5**	**2,357.0**	**1,424.7**	**2,131.0**

4.1.3 Review of DSO Non-network Related Expenditure

The CRU is proposing a non-network capital expenditure allowance of €670.6m for PR6, which is €116.2m (15%) lower than the €786.8m requested by the DSO. The proposed allowance represents a €241.0m (56%) increase relative to PR5 outturn. This increase is primarily driven by the DSO's 'head office accommodation/vehicles' (and tools) request totalling €434.2m. Notably, the CRU is proposing reopeners to enable additional allowances to be provided for 'IT and digital' projects (primarily within Distribution Asset Management) and Telecoms.

- For Head Office Accommodation/Vehicles, the CRU is proposing a €359.3m allowance[10] against the DSO request of €434.2m and a PR5 outturn of €213.7m. In its request the DSO states that it intends to deliver various projects, which include premises refurbishment, fixtures and fitting, construction of a new headquarters building, depot relocations, replacement and procurement of new and replacement tools and vehicles, and sub-programmes related to environmental obligations (principally wood pole remediation, storage and disposal). In setting the proposed allowance, the CRU notes

[10] Comprising allowances for: Property - €166.9m; Vehicles - €80.2m; Tools - €53.8m; and Other - €58.5m.

that there may be potential for the DSO to defer some activities and/or reduce the overall costs.

- For Distribution Asset Management, the CRU is proposing a €171.5m allowance against the DSO request of €193.5m. This represents an increase of 25% compared to the PR5 outturn of €137.5m. The DSO intends to use the costs to cover new roadmaps that have been developed as a response to the significant change that has occurred in this sector over the PR5 period. The CRU requires additional detail from the DSO to justify the level of investment requested and the expected outputs from this activity in PR6, which will form the basis of a delivery obligation covering 'work management, planning and delivery', 'cybersecurity' and 'core system foundations' sub-programmes.
- For Enterprise Applications, the CRU is proposing an allowance of €0.6m against the DSO request of €1.7m (with no equivalent allowance or outturn reported for PR5), representing a €1.1m (64.7%) reduction compared with the total request. The CRU requires further information to justify the full allowance for PR6, as no information was provided in support of the customer relations element of this programme.
- For Telecoms, the CRU is proposing an allowance of €139.1m against the DSO request of €157.4m (100% increase compared to PR5 outturn allowance). The DSO is proposing sub-work programmes to deliver a number of technologies and solutions to both maintain and expand the telecommunications network connectivity to HV locations. The CRU requires further information to justify deliverability of the proposals (in particular for the fibreoptic programme). A reopener is proposed to adjust the allowance as the delivery plan becomes firmer.

Table 20 below presents PR5 outturn, PR6 total request and Draft Determination allowances for the non-network related capex.

Table 20: Summary of PR6 Request for Non-Network Capex

Category	PR5 Outturn (€m)	PR6 Request (€m)		Draft Determination (€m)	
		Baseline	Total	Baseline	Total
Head Office Accommodation/vehicles	213.7	434.2	434.2	359.3	359.3
Distribution Asset Management (Support & Planning)	137.5	193.5	193.5	171.5	171.5
Enterprise Applications	0.0	1.7	1.7	0.6	1.7
Telecoms	78.5	157.4	157.4	139.1	157.7
Non-Network Total	**429.6**	**786.8**	**786.8**	**670.6**	**690.3**

4.1.4 Consideration of Storm Resilience in PR6 Proposals and Allowances

Since receiving the DSO's PR6 Business Plan in 2024, the CRU has received two additional submissions related to Storm Resilience. These submissions were made in the aftermath of Storm Eowyn and relate to Winter 2025 ('Enhanced Winter 2025 Grid Resilience Plan') and PR6 ('PR6 Scope Review').

The CRU's review of the Winter 2025 plan has indicated that it outlines clear actions, such as the creation of forestry corridors and the stockpiling of spare parts, but we observe that these include measures that would likely be challenging to implement in the short-term before the end of October. It should also be noted that at the time of writing the Winter 2025 plan the results of post-storm patrols and inspections were awaited such that detailed plans for targeted interventions could be confirmed. In addition, the review has highlighted some gaps that indicate that the DSO could have recognised learnings from reviews of storms in nearby jurisdictions (e.g. GB).

The PR6 Scope review was undertaken by the DSO 'to determine whether any further measures should be proposed to enhance resilience in addition to the substantial programme of work already outlined in the PR6 Plan'. The DSO has identified additional measures for consideration:

- Overhead Line Asset Replacement and Innovation;
- Timber Cutting;
- Ongoing Reviews & Planning; and
- Customer Learnings.

The CRU acknowledges the importance of the above measures in providing the necessary resilience, as well as the following statement by the DSO:

'The proposed changes identified in the PR6 Scope Review indicate additional costs of approximately €300m (€200m in CAPEX and €100m in OPEX) to provide for increased wood pole and conductor replacements (CAPEX) and enhanced timber cutting (OPEX). Given the scale of the existing PR6 CAPEX programme (€13.4bn) and the inherent uncertainty associated with delivering the full portfolio of projects, ESB Networks does not propose to increase the monetary value of the PR6 baseline CAPEX investment scenario (€10.1bn) or the total programme of €13.4bn as submitted.'

Based on the above, no changes have been made to the allowances proposed following consideration of the original request in the Business Plan submission provided by the DSO in November 2024.

It should be noted that, our analysis indicates that the proposed allowances include €0.89bn of investment to improve storm resilience[11], building on the Winter 2025 Grid Resilience Plan to implement lessons learned from Storm Éowyn. This is expected to include adopting robust approaches to network planning, customer service, vulnerable customer protection, organisational resilience and storm damage repair. Furthermore, should any additional specific information become available in the intervening period, then this will be considered as part of the Final Determination.

4.2 Forecast Operational Expenditure

The following sub section summarises the CRU's position on the DSO's forecast opex items over the PR6 period (2026-2030) as shown in Table 21 below. For opex, the forecast expenditure is assessed looking at the baseline, trends, steps, and outputs.

Table 21: Summary of DSO's Forecast Operational Expenditure over the PR6 Period (2026-2030)

Category	PR5 Outturn (€m)	PR6 Request (€m)		Draft Determination (€m)	
		Baseline	High	Baseline	High
Controllable Opex	1,678.9	2,586.1	2,586.1	2,084.5	2,336.1
Non-controllable Opex	348.3	425.2	425.2	424.9	424.9
Total	**2,027.2**	**3,011.3**	**3,011.3**	**2,509.4**	**2,761.0**

Overall, for controllable opex, against PR5 outturn of €1,678.9m, the DSO has requested €2,586.1m for PR6, which represents an increase of €907.3m (54.0%). This increase is primarily driven by the following cost categories:

- **Planned maintenance:** Requested increase of €403.0m which represent 108.9% increase from the PR5 outturn of €370.2m.
- **Meter Reading:** Requested increase of €266.6m which represent 547.0% increase from the PR5 outturn cost of €48.7m.
- **System Control:** Requested increase of €83.1m which represent 92.7% increase from the PR5 outturn cost of €89.6m.

[11] Estimated based on proposed allowances for Opex (Planned Maintenance, Forestry & Wayleaves) and Capex (Renew Prog – MV Overhead Lines, Rural LV Network, Urban LV Network and Continuity Improvement).

As stated previously, the cost assessment identified an efficient baseline to form the starting point for future PR6 costs, evaluated the forward trend in costs based on cost drivers and other assumptions and identified step changes proposed by the DSO that would build on the efficient baseline. The following subsections summarise the outcome of the review. A more detailed description and breakdown is provided in the accompanying Advisors' Report (CRU202599c).

4.2.1 Review of DSO's PR6 Operational Expenditure

The DSO requested a controllable opex allowance of €2.59bn for the PR6 period representing a €907.2m (54.0%) increase relative PR5 outturn expenditure. Following a review of the DSO's submission, the CRU is proposing a controllable allowance of €2.1bn. This is €405.6m (24.2%) higher than the DSO's PR5 outturn expenditure. As stated above, this step change is driven by an increase in the request for Planned Maintenance, Meter Reading and System Control, which represent 108.8%, 547.0% and 92.7% increases relative to PR5 outturn costs respectively. The key cost drivers for the increased request are explained below, followed by a summary of the base, trend and step assessment.

- **Increase in planned maintenance activities**: the DSO expects to increase timber cutting and rollout new technologies such as LiDAR[12]. It is expected that these increases will drive additional benefits for consumers such as shorter duration of, and a reduced number of outages.
- **Increase in customer relations activities:** The DSO plans including upgrading the scheduling support system and integrating it with other systems to provide more timely status updates to customers and increase visibility of tasks internally.
- **Increase in environmental management activities:** The DSO is planning for environmental improvement programmes and additional environmental assessments associated with the assessment of historic and current cable fluid leaks, HV substation sites associated with oil leakages, oil filled equipment and wood pole storage area.
- **Smart meter operational expenditure**: The DSO has included costs associated with the delivery of the customer awareness and engagement strategy, collecting data on a daily basis and training staff.
- **Meter reading:** The DSO expects continue to provide manual reads past the conclusion of the National Smart Metering Programme (NSMP), which is also necessary if meters

[12] This was due to be delivered in PR5

fail. The current meter reading team will support the upgrades of the smart meters. The workload of the team is also expected to increase in response to an increasing number of microgeneration connections.

Table 22 below presents the overview of the PR5 outturn, PR6 DSO request and the CRU's Draft Determination.

Table 22: Detailed Summary of DSO's Forecast Controllable Operational Expenditure Items over the PR6 Period (2026-2030)

Category	PR5 Outturn (€m)	PR6 Request (€m)	Draft Determination (€m)
System Control	89.6	172.7	109.5
Planned maintenance	370.2	773.2	552.2
Fault maintenance	303.1	283.2	281.1
Asset Management	134.6	147.7	142.2
Forestry & Wayleaves	15.6	35.6	14.5
Meter Reading	48.7	315.3	250.4
QH Data	10.5	16.2	12.1
Data Aggregation	35.8	34.7	34.3
Customer Meter Operation	4.7	-	-
Keypad / Token Meter	1.1	1.9	1.5
Smart Metering	68.8	-	-
Call Centre	43.9	60.2	58.6
Area Operations	67.4	71.7	70.6
Customer Relations	65.1	107.5	92.5
DUos Billing & Accounts Receivable	3.9	3.9	4.0
MRSO	8.4	27.9	24.8
Market Opening / Market Opening IT	59.2	63.5	52.8
Transaction charges	0.0	0.0	0.0
3rd party damages	36.4	0.0	0.0
Supply repayable	0.0	0.0	0.0
Other inter ESB	8.0	0.0	0.0
Other external repayable	0.1	0.0	0.0
Other commercial	15.7	0.0	0.0
Sustainability	0.0	0.0	0.0
R&D (Innovation)	22.5	34.4	25.0
Company Wide Costs	7.2	7.1	0.0
Corporate Charges & Corporate Affairs	69.3	97.9	69.5

Category	PR5 Outturn (€m)	PR6 Request (€m)	Draft Determination (€m)
Legal	18.5	17.8	17.6
Insurance	34.6	37.8	33.4
Pension	10.4	18.9	7.5
Environmental	30.3	48.4	48.5
Misc.	-0.4	0.0	-
Health & Safety	44.1	64.3	58.5
Telecoms	28.3	59.9	55.0
IT Opex	3.8	9.2	6.3
DMSO Flex	9.6	71.6	59.1
Contract and Vendor Management	0.0	3.6	3.0
Misc. non-regulatory	9.7	-	-
DSO Transformation	0.0	-	-
Total	**1,678.9**	**2,586.1**	**2,084.5**

4.2.2 DSO Opex Baseline and Trend

Based on the evidence submitted, the CRU has used the average of 2023 and 2024 outturn figures to set the baseline. This is for three reasons:

- To avoid yearly volatility, which refers to fluctuations in prices that may occur in a given year due to unforeseen factors;
- To use up-to-date values, to maximise the proximity of the outturn values we use to the start of the PR6 period; and
- To use actual, realised costs that have already been incurred as opposed to the use of forecast costs.

On a case-by-case basis, the default approach to setting the baseline may be adjusted where there is evidence to suggest that the approach set out above could represent an inappropriate baseline for PR6. This has been informed by the *ex-post* review of the DSO's opex over PR5.

The following summarises some of the key points related to the assessment and proposals on the DSO's PR6 baseline costs. Please note, the following points only focus on a number of key cost categories, further analysis is presented in the advisor's reports (CRU202599c).

System Control

System Control relates to the business critical operation and monitoring of the distribution network and includes costs associated with the DSO's National Distribution Control Centre (NDCC).

We use the lower of the DSO submission and the average of the 2023 – 2024 outturn for the PR6 baseline. Notably no benchmarking exercises or quantifications have been provided to justify the Operations Systems costs.

For Distribution Network Control and Control Room, the DSO has described the trends as being driven by an increased volume of network activities. For Operations Systems, and therefore Data, they have described how the increased volume of projects required to meet the targets under the Climate Action Plan (CAP) will lead to increased support, and assurance that they can comply with the NIS-2 directive. Additionally, the transition of Distributed Management System (DMS) applications from the Project Delivery to Operations Systems team will require resourcing and licensing agreements.

Planned Maintenance

Planned Maintenance refers to scheduled activities to improve the resilience of the distribution network. These activities are split across several sub cost categories, based predominately on asset type or activity.

In our assessment of PR5 High Voltage planned maintenance costs, we take the average of the 2023 – 2024 reported outturn as the representative baseline for all PR6. For the Rural Timber (MV Only), Urban MV/LV Timber and HV Timber, we take the average of the 2024 – 2025 outturn costs to be the PR6 baseline. The DSO did not request a trend adjustment for any subcategories. However, there is a significant increase in the request for the four major timber categories, and a lack of a base-trend-step breakdown.

The CRU will take the average of the 2023-2024 outturn for the Out-of-Cycle Timber, LiDAR Timber Management and Forestry Corridor Maintenance and hazard-patrol and follow-on because of an under-delivery and the need to increase baseline to enable delivery in PR5. On the Out-of-cycle hazard clearance we take the average of the 2023 – 2024 allowance, and inspection cost category we take the 2023 – 2024 outturn. Notably, the subcategories associated with inspection costs (maintain 38kV MESA switch and Fault Passage Indicators) are new for PR6 and have no base cost requests associated with them.

Meter Reading

In relation to meter reading, the CRU proposes an allowance of €250.4m, which is almost €64.9m (20.6%) lower than the DSO request. Meter reading is composed of 3 categories namely, meter reading, Smart Metering Operations Centre (SMOC) and meter inspection.

On SMOC, the main drivers of the service in PR6 are described as being increases in reporting, analytics and monitoring, as well as improvements to telecoms and cybersecurity. SMOC will act as a centre of excellence, with higher levels of testing. Customers will expect improvements in data, resilience, and up-time from smart meters, which will require improved delivery. We therefore see these increases as the main driver and again use the number of customers as a volume driver for PR6.

Customer Relations

The CRU is proposing a €92.5m allowance, which is €15.0m (14.0%) lower than the DSO's forecast. Within this allowance there are seven areas where the DSO requested step changes except connection services. The overall reduction is regarded as areas of further information for additionality and efficiency to a number of those step change requests.

For Connection Services, the DSO identifies new connection applications as the volume driver as they forecast an increase in demand exporting certificates, driven by technologies such as solar panels and also the need to continue digitising the process of Mast Interference Payments and moving to digital notification letters and electronic financial transactions.

The trend on Customer Awareness and Education will be driven by increased levels of activities to reach customers while Scheduling Support Centre volumes will be driven by a scheduling SaaS tool with a per-user licensing fee. Notably the trend on Transforming the Experience will be driven by incremental communications and engagement over time.

Meter Registration System Operator (MRSO)

CRU proposes a PR6 baseline based on the average of the 2023 – 2024 outturn. The DSO did not request a Trend adjustment for MRSO.

4.2.3 DSO Opex Step Change

The following summarises some of the key points related to the assessment and proposals on the DSO's PR6 step change. Please note, the following points only focus on a number of key cost categories, further analysis is presented in the Advisor's Report (CRU202599c).

Planned Maintenance:

For Forestry Corridor Maintenance, the step change is for a programme to identify forestry strandings which could reach conductors and cause faults. In this case, we have a lack of evidence that these costs are efficient; and that these works could not make use of resources from the Forestry & Wayleaves category. Therefore, we apply both a 25% efficiency and 25% additionality challenge.

On the LiDAR programme, we do not have evidence of cost estimation to justify efficiency, so we apply a 25% efficiency challenge. We also do not have full evidence that there were not internal resources which could have been employed for the project; we therefore apply a further 10% additionality challenge.

Meter Reading

For the SMOC, the DSO state that they are not expecting to observe a material step change and cannot quantify any extra workload other than that they will be contributing data, insights and design expertise. We therefore apply a 25% efficiency and 25% additionality challenge to this amount as it seems that this step is being treated as a buffer in case of increased activities.

On meter inspections, the meter inspection step will allow for a programme of cyclical visits to ensure asset health and meter sampling (a pilot programme will be conducted in PR6). We therefore apply a 15% additionality challenge.

Customer Relations

On Scheduling Support Centre, the step includes the extension of scheduling additional services and mobile reporting, along with a new centre of excellence. We have applied a 25% efficiency and 10% additionality challenge.

We do not apply a challenge on the Inclusive Customer Communication step which includes a request for new staff including translators and language experts, as well as compliance with Irish Language legislation, Visibility Act and Disability Act. This step would likely have large benefits to customers and is motivated by legislation.

On Understanding Customer Needs the step will include social listening reporting, and additional market research. However, it is not immediately clear if this could not have been delivered more efficiently under other social media activities. We apply a 25% efficiency and 25% additionality challenge to this subcategory.

MRSO

The DSO submitted the need for an enduring solution for battery storage and the need of substantial change to the sector. They also state that they want to automate the process for unmetered Group Meter Point Reference Number (GMPRNs) and Household Benefit Scheme to improve efficiency. It is not fully demonstrated that these costs are efficient. We therefore apply a 10% additionality and 25% efficiency challenge.

4.2.4 Benchmarking

As part of PR6, the CRU requested CEPA to conduct a top-down econometric benchmarking analysis of the DSO, to complement the bottom-up cost assessment and provide a more comprehensive picture and understanding of the DSO's costs and performance, and identify trends that warrant further investigation at PR6.

This top-down benchmarking exercise reviewed the DSO's total expenditure (totex) against that of electricity distribution network operators (DNOs) in Great Britain (GB).

The CRU has not used the results of the top-down benchmarking to directly set expenditure allowances for PR6, as has been the case in recent price reviews in the UK (by Ofgem, Ofwat and UR). Rather, the top-down benchmarking provides a cross-check to help validate findings from the cost assessment (i.e., the bottom-up analysis summarised above).

Overall, this analysis indicates historically that the DSO's totex has benchmarked well and consistent with GB peers once a range of external cost drivers and network typologies are controlled for. But during the PR5 period the DSO's totex has been increasing relative to the expenditure predicted from the models. Engagement with the DSO has noted some potential explanations for the difference:

- PR5 has been a period of increased investment in load and asset replacement related expenditure to catch-up for a period during PR3-PR4 when "*many essential network projects were deferred, creating a backlog of asset replacements and reinforcements*".
- Significant demand pressures on network capacity which have required a step up in totex during PR5 to address these bottlenecks and to manage the growing pressures from increased integration of renewable generation, adoption of heat pumps and electric vehicles, growing demand.

While it is acknowledged that DSO's submissions and responses provide important and plausible explanations for why totex has increased in PR5 and why it will need to increase further in PR6, it should be noted that comparator DNOs also face similar pressures (in particular, from demand drivers such as LCTs) to expand capacity during current and future price control periods.

Viewed in the round, we do not consider the findings provide a basis for the CRU to disallow incurred expenditure as part of the PR5 *ex-post* review. However, the trend in ESBN's relative totex performance compared to comparators suggests that strong, compelling, bottom-up programme business cases are needed to support the step up requested, particularly for load and asset-replacement expenditure in PR6. The findings on the DSO's relative cost performance also at least raise a question whether there might be opportunities for the DSO to explore how to increase its productivity during PR6 in terms of the output expected to be delivered from the allowances provided, while addressing the high-level network needs and requirements discussed above.

Another interpretation of the benchmarking is the system challenges that the DSO now faces may be revealing that the business needs to operate at a higher relative level of totex to deliver on the network needs. The CRU expects that the trends in the DSO's expenditure requirements will increasingly be observed in the expenditure of DNOs in GB and other jurisdictions as they implement their business plans to step up investment to 2030 and beyond. But the DSO's relative level of totex will over time need to reflect the specific challenges and needs of Ireland's electricity system which may diverge from other network areas. The CRU considers this is consistent with the conclusions from both the network needs assessment and the international trends analysis.

Overall, the CRU considers the benchmarking supports the DSO's current level of expenditure. But looking forward, it remains important that the further step-up in expenditure that is needed during PR6, is managed efficiently and effectively as possible by the DSO in the governance and delivery of its investment programmes and exploration of opportunities for productivity improvements where possible.

4.2.5 Frontier Shift

The CRU proposes to apply an *ex-ante* adjustment to allowances to account for ongoing efficiency and Real Price Effects (RPEs) in PR6, collectively referred to as 'Frontier Shift'.

The CRU aims to ensure that customers only pay for the efficient costs of developing, maintaining and operating the electricity distribution system. This is done by setting the network companies challenging but realistic and achievable targets and incentives. The CRU applies an ongoing efficiency / productivity challenge which is to encourage network companies to implement new technologies and management practices, replicating the forces of competition to drive out cost efficiencies.

More detail can be found in the published CEPA report (CRU202593).

ESBN state that macroeconomic trends in the Irish economy and the degree of dynamic change taking place within the electricity sector during PR6 limit the scope for achieving ongoing efficiencies. ESBN in particular cite low Total Factor Productivity (TFP) in the Irish economy as an important headwind.

The assessment undertaken by the CRU's advisors CEPA has however noted that there is evidence to support positive productivity growth over the PR6 period. A number of sources to estimate ongoing productivity were used and the analysis in (CRU202593) shows a wide range of productivity estimates:

- 0.5% - lower end; and
- 1.0% - higher end.

RPEs on the other hand are adjustments that reflect changes in the price of inputs net of HICP inflation adjustments that are already applied under the regulatory framework.

In recent price reviews, the CRU has tended to rely on an *ex-post* review of network companies' costs as the tool to manage real unit cost uncertainty and to facilitate that companies recover their efficiently incurred input costs over the price control period. If companies face substantial changes in their efficient costs due to input price pressures within the period, these will be reflected in allowed revenues as a true-up to cost allowances *ex-post*.

However, given the considerable scale of investment and risk of substantial cost forecast changes due to input cost volatility and supply chain constraints in PR6, there is a risk that delivery of the critical investment and transformation programmes required in PR6 could be hampered if *ex-ante* allowances do not include some upfront provision for RPEs and dedicated mechanisms are not in place to manage the risk of input costs increasing.

Therefore, the CRU are proposing to set cost allowances for Opex for the DSO which include an explicit *ex-ante* allowance for RPEs. The RPE allowance would not reopen until the *ex-post* review, and therefore the DSO would be expected to manage within this allowance within the price control period prior to the *ex-post* review. The CRU is not proposing to set *ex-ante* RPE allowances for capex, given the challenges in identifying appropriate indices in which to base the *ex-ante* allowance. Instead, the CRU is proposing to manage RPEs for capex solely through the PR6 *ex-post* assessment process, similar to how this was managed through PR5. The CRU considers the risks of under delivery associated with input price pressures is sufficiently addressed for PR6.

ESBN presented information as part of their business plan that suggested positive expected labour RPEs in the range of 1% to 1.8%, and materials RPEs in the range of 1% to 2.7% based on historic evidence of wholesale price pressures. The result of this analysis is a weighted opex RPE of 1% to 2% for the PR6 period. While the assessment undertaken by CEPA estimated a weighted average RPE allowance on total opex of 0.8 - 1.3% per annum for the DSO. More details of this assessment can be found in the published CEPA report (CRU202593).

Overall, the CRU is proposing to apply a Frontier Shift adjustment to the DSO's Opex of 0.1% per annum, which reflects the higher end of the ongoing efficiency range and the mid point of the RPE range. The CRU considers that this includes an ongoing efficiency challenge which is stretching but achievable, satisfying one of the key PR6 objectives to increase efficiency and protect customers. By setting the ongoing productivity factor at (and not above) our advisor's estimate, the CRU notes that the challenge is reasonable. The CRU also considers that this provide reasonable *ex-ante* provision for RPEs, which will enable the DSO to manage the risk of input costs increasing. Noting that the ex-post assessment process will be retained and used to review whether network companies efficiently managed input price pressures within the period.

This approach is in-line with regulatory precedent and is informed by CEPA's review of evidence of TFP and partial factor productivity growth rates in Ireland.

Table *23*: Frontier Shift Draft Determination

Network Company	PR6 Factor
DSO Frontier Shift (per annum)	0.1%

As the overall Frontier Shift adjustment is positive (i.e., an increase in allowed opex), this implies that for both network companies RPEs in Opex may be greater than the scope for both network companies' productivity improvements during PR6.

4.3 Conclusions

The CRU proposes to allow the DSO a gross capex baseline of €5,194.9m (with the ability to flex up to €7,003.4m during the period through use of uncertainty mechanisms). This is €1,478.7m (40%) higher than PR5 outturn and €2,297.6m (31%) lower than the DSO's total request. The CRU is proposing an allowance of €2.1bn on controllable opex. This is €405.6m (24.2%) higher than the DSO's PR5 outturn expenditure. The CRU notes the following.

- The CRU has challenged the DSO on a relatively large proportion of its forecast capital and opex, which we refer to as areas needed further justification and information.

However, if the DSO can provide further information to support a particular request, the allowances proposed in this paper may increase.

- Notably, if the DSO can provide sufficient justification for the areas where further information is required, these costs may be included—either in full, in part, or within an uncertainty mechanism—in the allowances set in the PR6 Final Determination.
- In addition to the areas requiring further information, the CRU is proposing to ringfence a proportion of the DSO's allowances for use in uncertainty mechanisms, Delivery Obligations (DO), volume drivers and re-openers.

Table 24 summarises PR6 forecast capital and opex for the DSO.

Table 24: Summary of PR6 Request and Proposed Draft Determination Capital and Operational Expenditure for the DSO

		Draft Determination (€m)	
	PR6 Request (Baseline)	PR6 Allowance (Baseline)	PR6 Allowance (High)
DSO Opex €m (Excl. Frontier Shift, inc. non-controllable)	3,011.3	2,509.4	2,761.0
DSO Opex (Incl. Frontier Shift, incl. non-controllable)	3,011.3	2,517.6	2,344.3
DSO Capex €m	6,617.7	5,194.9	7,003.4

Question(s):

4. What are your views on the DSO's PR6 Capex request and the CRU's proposed Draft Determination?
5. What are your views on the DSO's PR6 Opex request and the CRU's proposed Draft Determination?
6. What are your views on the CRU's areas of additional information as applied to the DSO's baseline allowances?
7. Do you have any comments or views on any of the proposals set out in this Section?

5 The Regulatory Asset Base

This section provides information on a number of interrelated issues that determine the DSO's RAB. Specifically, this section provides information on:

- the type of assets within the DSO's RAB;
- the methodology used to value the assets within the DSO's RAB;
- the length of asset lives applied to the assets within the DSO's RAB;
- the depreciation methodology applied to the DSO's RAB;
- the regulatory practice when an asset is physically replaced prior to being fully depreciated; and
- the regulatory treatment of (1) additions to the DSO's RAB and (2) claw back of revenue earned on assets that were not put in place.

5.1 Introduction

The revenue that the DSO recovers from its customers during each review period can be spilt into three separate categories:

1. revenue to cover the DSO's operational costs during that period;
2. a return on the capital that the DSO has invested in the distribution system assets; and
3. revenue to cover depreciation of those assets.

The RAB is the value on which the amount of depreciation that the DSO receives is based (item 3 above), and is the amount to which the rate-of-return is applied when determining the return on capital for the DSO (item 2 above).

5.2 Value and Composition

The approach to valuing the assets within the RAB is an important decision within the revenue control process. For the PR5 period, the CRU proposes to continue its current approach for valuing the RAB, that is, the DSO's RAB will be valued using a replacement cost approach. This approach has been used in all review periods to date. The CRU considers that this approach remains appropriate and furthermore has the benefit of maintaining regulatory certainty for PR5. For further details on this approach and other approaches please see Appendix 4.

Table 25 shows the DSO's PR6 RAB as forecast in CRU's draft determination for PR6, while Table 26 shows the contribution of each of the RAB categories to the total capex spend in each year of PR6.

Table 25: DSO's PR6 RAB

(€bn, 2024 prices)	2026	2027	2028	2029	2030
Opening Asset Value	**8.13**	**8.40**	**8.73**	**9.18**	**9.69**
Capex	0.76	0.86	1.00	1.11	0.81
Depreciation	(0.47)	(0.51)	(0.54)	(0.57)	(0.60)
Secondary Asset Adjustment	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)
Smart metering Adjustment	(0.04)	(0.03)	(0.03)	(0.03)	(0.03)
Closing Asset Value	**8.40**	**8.73**	**9.18**	**9.69**	**9.89**

Based on the capital expenditure proposed is set out below in Table 26 below.

Table 26: DSO's PR6 Capex

(€m, 2024 prices)	2026	2027	2028	2029	2030
Load related capex	451	568	703	821	557
Non-load related capex	165	178	198	199	197
Non-Network capex	144	139	134	138	116
Smart Metering	124	105	99	84	76
Contributions	(130)	(131)	(129)	(130)	(131)
Total capex	**755**	**859**	**1005**	**1111**	**815**

The CRU's DSO revenue model (CRU202599i) which is published with this document contains information on the composition of the RAB projected movements in the DSO's RAB over PR5.

5.3 Asset Lives Applied to RAB

The assets lives applied to assets within the RAB feed through into the level of depreciation that the DSO receives on those assets within each control period (or year).

In the last number of price reviews the CRU has used average assets lives of 45 years for the DSO's network assets.

Table 27: Assets lives Applied to Assets within the RAB

Asset	PR6 (yrs)
110kV networks assets	**45**
HV/MV/LV network assets	
IT	**5 or 7**

Office equipment	**10**
Fixtures & fittings	**5**
Scanda telecoms	**15**
Vehicles	**7**
Premises	**50**
Tools	**5**
Telecoms	**15**
Grants	**45**
Smart Metering	**10**
Customer Contributions	**45**
Continuity	**15**
System Control	**10**
Other	**45**

The CRU intends to continue using average assets lives of 45 years for the DSO's network assets. The asset lives applied during PR5 for the various types of assets within the DSO's RAB are detailed in Appendix 3. The CRU intends to continue to apply these through the PR6 period.

5.3.1 ESBN's Proposal on Technical Asset Lives

ESBN commissioned consultants, WSP, to carry out an assessment of asset lives for electricity network assets for distribution and transmission. WSP's technical report was provided to the CRU as part of the DSO's Business Plan submission (full version received in early May 2025).

WSP's report describes the methodology used to estimate new asset lifetimes primarily for distribution assets, but also with reference to transmission assets. The estimations are based on the change in asset profile data between PR5 and PR6 for each installation year, which in turn is used to determine the volume of assets removed and the average age of assets when removed from service. This data is summarised to determine the retirement age which is compared against the rated technical life of the asset.

Examples for various assets, such as MV pole mounted transformers, and underground cables, are presented in the document along with average age profile information for distribution and transmission. WSP's assessment concludes that "*In general, the calculated average asset age at retirement for each asset category tends to be lower than the rated technical lifetime, which supports a reduction in the economic life*". WSP adds that depending on asset type this can be between 9% and 46% lower than the assets rated life for distribution, and that a similar reduction on asset lives would be expected for transmission assets.

5.3.2 Review of ESBN's Proposal on Technical Asset Lives

In setting the asset life assumption for the purpose of the depreciation calculation, it is important to consider evidence on whether the technical asset life has materially changed or is expected to materially change.

ESBN, through WSP, have provided a report that focuses primarily on 'retirement age' as opposed to 'asset life'. In several places the document provides examples illustrating where assets have been removed from the network for reasons other than non-load related replacement. The primary examples given are replacement due to overloading of 110 kV and 38 kV transformers and changes in engineering standards for pole mounted transformers. Other examples of retiring assets before they have reached their asset lifetime include diversions, undergrounding or changes to network configuration.

The CRU notes though that the report only provides a high-level overview of specific assets that have been retired before their asset lifetime and thus detailed analysis of the materiality of these asset retirements on the overall asset base is difficult to establish.

While it is recognised that some assets may need to be retired ahead of their asset lifetime due to reasons other than non-load related intervention, the CRU does not consider it appropriate to adjust the asset lifetime for these instances. The asset lifetime estimations should be based on the technical performance of an entire asset group, informed by data related to non-load related replacements. In this instance, ESBN should be applying the expected asset lifetime for each particular asset group regardless of whether it may or may not be identified for replacement ahead of its asset lifetime. For example, it is anticipated that over the course of PR6 and PR7 a large volume of load related interventions will be required. Adjusting the asset lifetime in accordance with the methodology outlined in the WSP's report would therefore result in a significant decrease in asset lifetime. However, the new assets installed as part of the load related interventions would be expected to have an asset lifetime in line with industry standards and not a shortened lifetime, skewed because of load related inventions previously made.

WSP's report also refers to changes in engineering standards with respect to pole mounted transformers, with the minimum standard rating increasing from 15 kVA to 33 kVA. The findings in WSP's report implies that due to this change in standard, significant volumes of transformers will need to be replaced. However, changes in engineering standards should not result in programmes to retrospectively replace existing assets. Instead, asset replacements should be driven either by load related or non-related reasons as opposed to changes to engineering standards to increase capacity of assets.

While WSP's report provides a useful overview of the interventions that ESBN are carrying out across the network due to system reinforcement, specific manufacturer issues and other non-load related issues, the CRU does not consider that it has fully addressed why the asset lifetime of a particular asset group should be adjusted downwards for PR6.

The CRU recognises that assets may need to be replaced ahead of their asset lifetime, however, changing the anticipated asset lifetime would need to be based on substantive evidence to demonstrate that particular asset groups were experiencing failures or accelerated deterioration, resulting in the need to reduce the asset lifetime. The CRU also notes that evidence should be considered on the impact that advanced monitoring technology, enhanced maintenance routines and better asset knowledge for example, is having on asset lives. However, this has not been evidenced yet by ESBN, or its advisors, and would likely require several years of data to understand the impact.

As noted in Section 5.3, the CRU intends to retain the current approach and continue using average assets lives of 45 years for the DSO's network assets. However, the CRU would welcome further input and evidence from ESBN on this matter, and propose to continue engagement on this ahead of Final Determinations.

5.4 Depreciation Methodology

The CRU has used a straight-line depreciation methodology for the previous price review periods, and proposes to use this approach for PR5.

5.4.1 Context

Economic depreciation profiles allocate the original capital cost of a project over its useful life. There are a number of possible methods through which asset bases may be depreciated; common relevant examples are straight-line, sum-of-years-digits and declining balance depreciation.

When setting the first revenue control, covering the period 2001 to 2005, the CRU chose the straight-line method. The following benefits were noted:

- Due to the nature of the design life of network assets and the load profile of the use of network assets, the straight-line method was a reasonable representation of economic depreciation for network assets.

The straight-line approach to depreciation was then continued when setting the second, third and fourth Price Reviews.

5.4.2 PR6 Proposal

For the review period covering 2026 to 2030, the CRU intends to continue applying the straight-line method of depreciation used during previous price review periods. Maintaining regulatory certainty by continuing this methodology was a factor in this proposal. However, regulatory certainty aside, the rationale that led to this approach being chosen in the first instance are still applicable for the forthcoming period.

5.5 Replaced Assets

When setting the price review covering the PR2 period from 2006 to 2010, the CRU noted that a significant amount of expenditure had taken place in the last decade on replacing assets in ESB's networks. This could possibly lead to a situation where an asset and its subsequent replacement would both be included in the RAB at the same time, that is, the asset has been replaced before its value in the RAB has been fully depreciated. In the PR2 decision paper (affirmed in the PR3 decision) the CRU stated its view that assets included within the RAB that have been replaced should be removed from the RAB at the time of their replacement.

The CRU proposes that this policy should also be applied during the PR6 period where material values of assets are replaced before being fully depreciated. However, the CRU will also take into consideration that using an average asset life for a class of assets may extend a subset of assets beyond their planned depreciation life.

5.6 Capital Expenditure Approved but not Incurred

The CRU proposes that revenue collected by the DSO to cover return and depreciation on projects which were planned for the 2021 to 2025 period and subsequently not put in place will be netted off the revenue to be collected by the DSO during the 2026 to 2030 period. To a large extent this has already occurred in the annual revenue adjustments, but to the extent any non-expenditure of capital expenditure remains it will be accounted for in the k-factor adjustments during PR6.

5.7 Additions to the RAB

The regulatory treatment of additions to the DSO RAB is an important issue in a price review. This section explains and proposes to continue the current regulatory approach to treatment of additions to the DSO RAB for:

- Interest During Construction (IDC); and,
- Capital contributions and grants.

5.7.1 Interest During Construction (IDC)

In previous price reviews, assets were added to the RAB as costs were incurred, not on the date of commissioning. The DSO received a return on the assets from the middle of the year in which the costs were incurred, rather than when the asset was commissioned. For this reason, the CRU did not allow IDC to be added to the RAB.

Depreciation was also provided as expenditure on assets was incurred. This means that expenditure on assets still under construction during any given year will be included in the calculation of that year's annual depreciation charge.

Not allowing IDC, or not adding assets to the RAB as the costs are incurred, has two potential effects:

- it may cause a mismatch of cost and revenue, meaning that the DSO has insufficient funds; however, on the other hand,
- it may provide an incentive on the DSO to fully deliver the assets in order to start the flow of depreciation and return, to the advantage of customers.

In PR4 the CRU decided that assets which have been added to the RAB, but have not been energised within five years (except in the case where the programme of work was scheduled to be longer than five years or where the DSO can satisfactorily show that the delay is beyond its control) would be temporarily removed or "paused" from the RAB (with all return and depreciation paused) until the point at which the asset can be energised and utilised. At this point, this does not result in any current reductions/ removals from the DSO RAB.

The CRU proposes to continue this policy, regarding IDC, during the forthcoming revenue control period, covering 2026 to 2030.

5.7.2 Capital Contributions and Grants

In previous price reviews, capital contributions and grants were subtracted from capital expenditure in the relevant year.

The CRU proposes to continue this policy during the forthcoming revenue control period, covering 2026 to 2030.

5.8 Conclusions

The CRU is not proposing changes the RAB methodology relative to that employed during the 2021 to 2025 period. As summarised above, the CRU has considered the asset lives proposal and has concluded that it will retain the current approach and continue using average assets lives of 45 years for the DSO's network assets.

Question(s):

8. What are your views on the CRU's review of ESBN's asset lives proposals?
9. Do you have any comments or views on any of the proposals set out in this Section?

6 Cost of Capital

The CRU, with the assistance of expert financial advisors, sets the fair rate of return that the regulated network companies can earn on the efficiently incurred capital investments in its regulated asset base. This return is known as the Weighted Average Cost of Capital (WACC).

6.1 Introduction

The WACC is a weighted average of the cost of debt and the cost of equity.[13] It is the CRU's role to set a WACC that gives a fair deal to customers and the companies. If the CRU sets a rate of return that is too high, customers end up paying too much. If the CRU sets it too low, utilities cannot raise the finance to deliver the necessary level of network investment, which can result in a reduced quality of service for customers. Setting a fair rate of return helps the utilities manage their challenges, such as financing their investment programme.

Consistent with many other regulators in similar environments,[14] when setting the appropriate cost of capital, the CRU has used a WACC methodology, estimating the cost of equity using the Capital Asset Pricing Model (CAPM) and the cost of debt using the data from capital markets. The CRU has used this methodology to set the cost of capital for the utilities it regulates including gas, water and electricity.

The CRU published an Information Paper in February 2020 setting out the principles for estimating the cost of capital across electricity, gas and water in Ireland.[15] This paper noted that the CRU continues to review its methodology with the aim of ensuring it provides the best outcomes for customers.

ESBN is a 'asset heavy' business with a high proportion of long-term fixed assets. In the PR6 period, ESBN will need to deliver a very significant step up in its investment programme , and thus the level of WACC set by the CRU would be critical in enabling the price control to be financeable for the licensee. The cost of debt reflects the average cost of finance over the PR6 period, including compensation for existing debt costs issued prior to PR6 (embedded debt) as well as issuance during PR6 (new debt).

[13] For a notional company, not the true cost of debt and equity experienced by the companies
[14] This methodology is widely used by other Irish and European regulators in the electricity, gas, telecom and aviation industries.
[15] CRU20029 Cost of Capital CRU Approach

This Draft Determination Paper presents the results of the work that was completed when deriving the proposed costs of capital for the DSO. A report provided by CEPA – Price Review Six Onshore Cost of Capital (CRU202594) has been published alongside this paper and interested parties should refer to that document for further detailed information on these issues.

6.2 Methodology

The cost of capital value set out in this paper has been derived using an established CRU WACC methodology and approach, including using the CAPM for the cost of equity[16], and as such this paper is restating the CRU's intention to continue using these methodologies to calculate the appropriate costs of capital for the DSO, for the 2026 to 2030 period. Several key factors considered when estimating the cost of debt and cost of equity as set out below.

6.2.1 Key considerations in setting the WACC

The CRU considers a number of factors when setting the cost of capital. These have been reflected below, along with the rationale for PR6 cost of capital considerations.

Notional or Actual Capital Structure

The standard approach that CRU has taken in previous price reviews (and in line with economic regulation in Ireland, UK and other European countries) is to set the allowed WACC with reference to a notional rather than actual capital structure for the regulated entities.

A notional capital structure ensures that the consumers only pay for efficient cost of capital. This means that any risks, and associated costs, of financing decisions made by the regulated companies, such as the level of gearing, timing of debt issuance, and choice of debt instrument, are ultimately paid for by the shareholder and not the final customer. The consumers' prices therefore only reflect the financing costs that a notionally efficient business would incur under the price control[17]. At the same time, a notional capital structure incentivises the utility business to seek efficient low-cost financing.

The CRU has thus assumed a notional capital structure for the utility businesses for determining the cost of capital and carrying out financeability assessment[18] for PR6.

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16 CAPM is used for estimating the cost of equity.
17 As noted by the CRU in its Offshore Revenue Model decision paper - CRU202499.
18 See section 7 on financeability.

Tax Treatment

Since the network entities are state-owned, it is assumed that the companies follow the headline corporation tax rate (12.5% in Ireland), rather than having a bespoke tax rate. The CRU has thus historically adjusted the post-tax WACC for headline corporation tax levels to derive the pre-tax WACC. Ireland signed up to the OECD pillar Two agreement in October 2021, including the agreement of a global minimum effective tax rate of 15% for firms that meet certain conditions. The Finance (No. 2) Act 2023 implemented the Pillar Two minimum effective tax rate in Ireland19. For PR6, the CRU thus proposes to adopt a tax range of 12.5% - 15%.

Real or Nominal WACC

A nominal rate of return includes inflation, whereas a real return excludes inflation. The regulated asset bases of ESBN and EirGrid are indexed to inflation, providing a return to the investors which compensates for inflation. The CRU thus sets a real WACC to ensure that the investors are compensated for inflation only once. The CRU purposes to continue with this approach for PR6.

Data used to estimate WACC

For PR5, CEPA used Eurozone data rather than Irish-specific data. For PR6, CEPA have continued with this approach, the rationale being that:

- the investors are more likely to view Irish regulated companies as part of an asset class that includes European utilities;
- the European dataset is richer than the more limited Ireland-only data and is more likely to produce statistically robust estimates; and
- in a monetary union such as the Eurozone, individual countries would be expected to converge to a long-term equilibrium.

Aiming up

There are risks associated with setting a WACC which is too low or too high. Since WACC is the rate of return that can be earned on the RAB, setting a low WACC would lead to a reduction in investment levels and consequently a reduction in the service standards, thus resulting in long-term disadvantages to the customers, even though they might benefit from lower bills in the short

[19] See Guidance on Pillar Two available here.

run. On the other hand, over-funding can lead to investors receiving increased returns at the expense of customers. Setting too high a WACC, however, is considered to be less harmful as the increased return can create incentives to innovate and invest, which would ultimately benefit the customers in the long run.

The CRU and other regulators have historically adopted the view that the long-term consequences of underestimation are worse and have thus set a WACC in excess of the level implied by the WACC formula. This increase is known as 'aiming up'. In PR4, PR5 and PC5, the CRU has aimed up to the 67th percentile. The CRU, however, does not mandate the use of the 67th percentile.

The CRU cost of capital approach paper (CRU20029)[20] states that:

"*The CRU may also consider the context of the sector and any unique characteristics associated with the utility when coming to a decision on aiming-up. For example, the nature of the capital programme, the utility's funding model, and levels of uncertainty may be amongst the factors that the CRU takes into account when setting the aiming-up level for the WACC, if any.*"

For PR6, the 67th percentile of the range is proposed, which is consistent with PR4, PR5 and PC5.

6.2.2 Building Blocks of WACC

The CRU sets the allowed rate of return as a Weighted Average Cost of Capital (WACC), weighting together debt and equity costs, using the following formula:

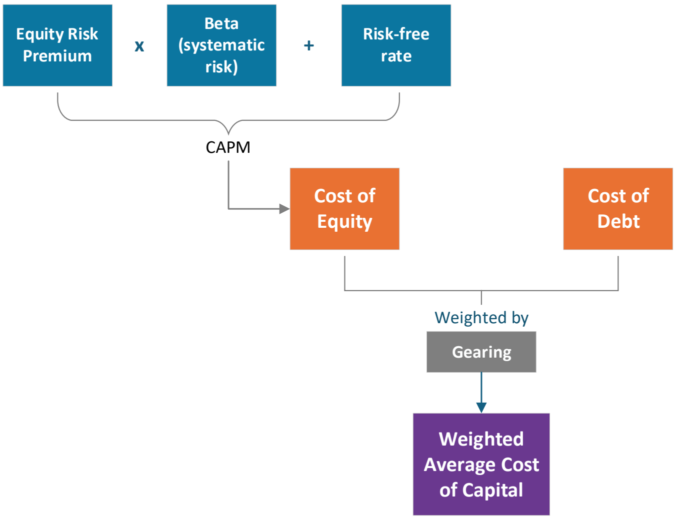
$$WACC = \left(\frac{E}{D+E}\right) * CoE + \left(\frac{D}{D+E}\right) * CoD$$

- 'CoE' is the cost of equity;
- 'CoD' is the cost of debt;
- 'E' and 'D' are the total values of equity and debt respectively; and
- (D/(D+E)) represents notional gearing which is the proportion of debt that a regulated entity would hold.

Figure 8 below shows the different components that make up this cost of capital.

[20] CRU/20/029 – Cost of Capital – CRU Approach – Information Paper

Figure 8: Building Blocks of Cost of Capital



The approach taken by the CRU along with the estimated value for each component of the rate of return is set out in the following sections.

6.3 Estimating the PR6 Cost of Capital

The CRU's advisors have assessed ESBN's methodologies used in estimating the different components of the Cost of Capital. The below table provides a RAG status against each component, highlighting the degree of difference in the approaches taken by the utility business and CEPA[21]. Full details of the methodology and estimates can be found in the accompanying CEPA Price Review Six Onshore Cost of Capital report (CRU202594).

Table 28: Difference in CEPA vs ESBN's Proposed Approach to PR6 WACC Estimation

WACC component		CEPA vs ESBN (DSO)
Cost of Equity	Risk-free Rate	Minor
	Total Market Return	Minor
	Asset Beta	Minor
	Debt Beta	Uniform
	Equity Beta	Uniform

[21] The RAG status only indicates the differences in methodologies and is not an indication of the differences (or similarities) in the estimates. See Section 6 on WACC estimate proposals.

	Tax Rate	Minor
Cost of Debt	**Benchmark Cost of Debt**	Major
	Adjustments	Uniform
	Inflation adjustment	Minor
Gearing	**Notional Gearing**	Uniform

The PR6 approach taken by CEPA to estimate these WACC components is set out in the below sub-sections.

6.3.1 Cost of Equity

The CRU has historically used the (CAPM) to estimate the cost of equity. This approach is continued for PR6.

Risk-free Rate (RfR)

In previous price controls, long-term German government bonds have been considered as a proxy for risk-free rate. CEPA propose to continue with this established approach for PR6. German bonds are regarded as a good proxy for the risk-free rate of return on the Eurozone investments, as they are widely considered to have negligible default risk. CEPA have not adopted the forward curve adjustment suggested by ESBN.

Total Market Return (TMR)

CEPA focus on the historical *ex-post* and *ex-ante* evidence when estimating the TMR, utilising the Dimson, Marsh and Staunton (DMS) data series estimates. ESBN focused on only the historical *ex-post* approach.

Asset Beta

For PR6, CEPA have estimated the asset beta using a wider comparator set and a 'pure-play'[22] comparator set, placing more weight on the latter. 'Pure-play' energy comparators have greater similarity to the notional entity in terms of risk profile and thus are likely to provide a better evidence base for beta. This is in line with the PC5 determination. CEPA have used a slightly different comparator set to ESBN.

[22] Pure play comparators are companies with a substantial part of their business energy network related.

Debt and Equity Betas

CEPA propose to assume zero debt beta for the DSO, consistent with the CRU regulatory precedent, as ESBN have done. The asset beta is then combined with the notional gearing to arrive at the equity beta.

Tax Rate

The CRU has historically used the headline corporation tax figure of 12.5% for Ireland. CEPA have used a range of 12.5% to 15% (in case of uncertainty around the headline number) as the corporation tax range for PR6 for the DSO.

6.3.2 Cost of Debt

At prior price reviews, the CRU has calculated notional debt rather than using the utility companies' actual cost of debt to ensure that the consumers only pay for efficient debt costs. The CRU focused on the use of an "all-in" cost of debt in PR5, using a 10-year trailing average of historical rates observed, not making a distinction between debt taken out before and after the price control period for the network owner. The DSO will enter PR6 with existing debt which has existed since prior to the start of the PR6 period (embedded debt), a share of which will need to be replaced with / refinanced over the course of PR6. It will also need to raise new debt to finance some of its significant scale up in capital expenditure. For PR6, the CRU has thus looked at estimating the cost of debt by taking a weighted average of the embedded debt and new debt.

6.3.3 Gearing

The CRU assumes a notional gearing level for the regulated companies, independent of their actual gearing. The CRU has consistently used a standard gearing level of 55%, in line with the levels assumed by other regulators in the UK and Europe.

For PR6, ESBN assessed the gearing levels in other comparator companies and proposed to retain the 55% notional gearing level. Consistent with the company's proposal, and in line with the regulatory precedent, CEPA agree with the proposed notional gearing assumption of 55% for the DSO. CEPA's financeability assessment shows that this level is appropriate within the context of PR6.

6.4 Conclusions

This section lists the cost of capital recommendations provided by CEPA to the CRU for the period 2026-2030 which reflects updated market data. It also lists the values of the factors that underpin this estimate. The DSO proposals are summarised in the CEPA report (CRU202594). These figures are also included in Table 29 below, along with the DSO's proposed figures for comparison purposes.

Table 29: Cost of Capital Estimates and Proposals - DSO

	CRU PR6		DSO	
	Lower	Upper	Lower	Upper
Benchmark cost of debt	1.18%	1.50%	1.15%	1.49%
Small company premium	N/A		N/A	
Premium on Irish utilities	N/A		N/A	
Issuance costs	0.10%	0.20%	0.10%	0.20%
Cost of debt	**1.28%**	**1.70%**	**1.25%**	**1.69%**
Risk-free rate	0.50%	0.60%	0.36%	0.65%
Total market return	6.40%	6/80%	6.45%	6.80%
EMRP	5.90%	6.20%	6.09%	6.15%
Asset beta	0.31	0.35	0.31	0.35
Equity beta	0.69	0.78	0.68	0.77
Cost of equity (post-tax)	4.56%	5.42%	4.52%	5.41%
Tax	12.5%	15%	12.5%	
Cost of equity (pre-tax)	**5.22%**	**6.38%**	**5.17%**	**6.18%**
Notional gearing	55%			
WACC (real, pre-tax)	**3.05%**	**3.81%**	**3.01%**	**3.71%**
Adjustment for inflation expectation	0.10%	0.40%	0.58%	0.83%
WACC (real, pre-tax) after adjustment for inflation expectations	**3.15%**	**4.21%**	**3.6%**	**4.54%**
Cost of Capital	**P67=3.85%**		**P67=4.23%**	

The following should be noted in conjunction with Table 29

- CEPA's point estimate of ESBN's WACC based on the 67th percentile of the range is 3.85%, which is lower than ESBN's WACC estimate of 4.23% (also based on the 67th percentile), primarily due to a difference in the inflation adjustment estimate.
- ESBN's assessment found German inflation to be consistently above Irish inflation during the past 10 years (2014 – 2024) and stable between 2014 and 2020. Their assessment did not focus on the decreasing size of this gap between 2020 – 2024. CEPA's assessment noted that while the historical data might imply that a larger adjustment is required, this data may have been influenced by macroeconomic events that may not apply in future (e.g., impact of Brexit on Irish inflation), and so CEPA apply caution in placing much weight on this data.

CEPA thus consider a small uplift to account for the wedge between Irish and German inflation as compared to ESBN's uplift of 0.6 – 0.8%, resulting in a lower inflation adjustment range than ESBN.

- The cost of debt proposed by ESBN is slightly higher than PR5, while CEPA estimate involves a narrower range due to higher new debt costs mitigated by lower embedded debt costs.
- The TMR range was relatively wide at PR5, however, during PC5[23] the lower bound of the range increased in line with the new GB regulatory precedent / regulatory guidance. The CEPA proposed PR6 range is much closer to the PC5 determination.
- ESBN proposed a reduction in asset beta which is in line with the direction applied in PC5[24] and is considered to be appropriate by CEPA.

Question(s):

10. What are your views on the proposed methodology for estimating the cost of capital?
11. Do you have any comments or views on the proposed estimates for the WACC parameters?

[23] See CRU2023139
[24] PC5 applied an asset beta range of 0.33 – 0.37.

7 Financeability

The CRU is required to have regard to the ability of network companies to finance their operations. The CRU has consistently interpreted this as to ensure that an efficient licence holder, in this case the DSO, can finance its activities. The CRU has made some assumptions in this respect which are:

The DSO does not exceed the allowance for operating costs.

- The allowed operating costs are set at the level an efficient utility can achieve.

The financeability assessment is based on the notional capital structure assumed by the CRU.

- It is not the function of the CRU to specify the capital structure of the DSO, to the extent the actual differs from the notional any costs should be borne by the shareholder and not the final customer.
- If financeability assessment is based on an actual gearing level, achieving a certain credit rating might lead the utility business to raise its debt (gearing) levels, resulting in the regulator having to increase the cashflows (allowed return and depreciation) to ensure that the business can meet its debt obligations while remaining financeable.

The effects of any unfinanced pension deficit are a matter for the network companies.

- The treatment of any pension deficits within the utility will not be dealt with as part of the PR6 process.

7.1 Summary and Conclusions

The financeability test is based on the DSO achieving an investment grade credit rating. Rating agencies take a number of factors into consideration when determining the rating of a company, such as quantitative metrics (like interest coverage ratios), as well as qualitative factors such as the stability and predictability of the regulatory regime and company financial policy.

ESBN conducted a financeability assessment based on their baseline and Agile Investment and Monitoring Framework (AIMF) adjusted allowance proposals[25], noting that significant investments through the AIMF could potentially undermine the financeability of the business,

[25] ESBN proposed a baseline + AIMF-adjusted allowance of €13.4 billion.

which in turn would require ESBN to defer their AIMF investments. To manage this risk, ESBN proposes the following:

- the CRU should ensure that the business is financeable at the minimum level of defined *ex-ante* AIMF spend (13.4 billion); and
- the PR6 framework includes a reassessment of financeability if the AIMF investment needs reach a level which is unfinanceable. The reassessment will thus be triggered if the AIMF levels reach or exceed the pre-determined non-financeable outcomes (e.g. exceed the minimum *ex-ante* AIMF level of €13.4 billion over PR6).
    - ESBN will provide evidence showing that the resulting financial metrics indicate a financeability challenge, thus requiring a reassessment to adjust for the revenue gap to the minimum threshold.
    - The revenue gap will be addressed through an appropriate defined intervention (such as increased revenues or higher WACC) that ensures financeability of the business.

The CRU have noted ESBN's proposal for financeability reassessment and **do not consider that a financeability reopener should be included in PR6** framework proposals at this time. CEPA have tested the proposed package on a high case scenario and find the price control proposals to be financeable with sufficient headroom in the underlying cash flow and interest cover ratios.

ESBN currently finances its network investments through ESB Group and as such any rating of ESBN as the DSO is notional. Moody's August 2024 credit rating for ESB is A3 (Positive)[26]; which has been revised from Stable to Positive outlook.

In carrying out financeability assessments for the regulated companies (in this case the DSO business and not the Group it's part of), the CRU does not consider it appropriate, nor is it in any case possible, to replicate all the factors that the credit rating agencies take into consideration when developing a credit rating. However, the rating agencies do publish their methodologies for rating regulated utilities, and this gives guidance on what factors are taken into consideration, and the financial metrics associated with the different credit ratings. The financial ratios

[26] ESB Credit Ratings – Moody's; Moody's A3 rating for ESB is maintained in its 2025 outlook on Regulated Electric & Gas Networks Europe (published on 10 April 2025) , while the overall outlook for the sector has changed from stable to negative.

consistent with Moody's Investment Grade Credit Rating are set out in Table 30 below[27]. See CEPA report – Price Review Six Financeability Assessment (CRU202596) for more detail.

Table 30: Financial Ratios Consistent with an Investment Grade Credit Rating

Moody's[28]		
Metric	**A**	**Baa**
(FFO[29] + Interest)/Interest	4.0x – 5.5x	2.8x – 4.0x
FFO/Net Debt	18% - 26%	11% - 18%
AICR[30]	2.0x – 3.5x	1.4x – 2.0x
RCF[31]/Net Debt	14% - 21%	7% - 14%

The CRU considers that the regulatory regime in Ireland is consistent with international best practice and provides a stable and transparent framework within which the DSO operates. In terms of the financial profile, the CRU has assessed the DSO with regard to the financial ratios set out above and considers that the allowed revenues provide for sufficient headroom on these key credit metrics for the DSO to be considered financeable, with overall metrics consistent with comfortable investment grade [32].

The CRU, having engaged with its advisors, is of the view that based on the notional financial metrics of the combined DSO-TAO entities and investment plans over PR6, the WACC of 3.85% is consistent with ESBN being adequately financeable over the period.

To deliver this investment programme, ESBN will need to access significant amounts of new debt and equity capital. Illustrative CRU modelling suggests for ESBN an equity requirement may be required in the baseline (assuming 55% notional gearing and current ESB dividend policy), which would increase under the high case.

Question(s):

12. Do you have any views on the assessment of financeability?

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[27] We have considered individual metrics from other rating agencies, including S&P, in forming our assessment.
[28] Moody's ratings, Regulated Electricity and Gas Networks, 2022, Exhibit 2 – available here.
[29] Funds From Operations
[30] Accrual-based Interest Coverage Ratio
[31] Retained Cash Flow
[32] The simulated outcome following Moody's 2025 Moody's Regulated Electric & Gas Networks Rating Methodology paper (dated August 2024).

8 Allowed Revenues and Profiling

The subsections below set out the allowed revenues for the DSO, as determined within the CRU's revenue model.

8.1 Revenue Profiling

The PR6 price profile is defined as the profile of revenues the CRU sets at its Final Determination, which will be influenced by choices on how the CRU chooses to sculpt and smooth (or not smooth) its allowed revenues at PR6. As detailed in this Draft Determination, a significant increase in allowed revenues is forecasted for the network companies for the PR6 period, which has implications for the PR6 price profile.

The CRU must balance a number of criteria when assessing and defining the price profile for PR6. These are summarised below:

- **Legitimacy:** The price profile achieves an appropriate balance of distributional and intergenerational equity between consumer groups. The proposals are proportionate.
- **Financeability:** The price profile enables the price control to be financeable, for example, in potentially facilitating the notional efficient company achieving key credit metrics.
- **Cost reflectivity:** Overlapping with legitimacy, the price profile ensures that users of the network are making a proportionate contribution to its costs given the objectives for PR6.
- **Practicality and simplicity:** As far as possible, the approach to determining the price profile should be targeted and as transparent and simple as possible.
- **Predictability and volatility**: The price profile for PR6 should deliver stable and predictable tariffs as far as possible, and avoid undue volatility of bills.

Taking the above into account, the CRU's proposed approach for PR6 is to set a baseline revenue allowance that reflects CRU's view of core efficient opex and capital maintenance and an initial *ex-ante* allowance for enhancement related expenditure, with the network companies having the ability to access significant additional revenues through the AIMF where clear milestones or triggers are met. The proposed level of agile revenues seeks to balance the predictability of the price profile with legitimacy, while enabling a financeable price control.

The proposed allowed revenues for the DSO is set out in Table 31 below, respectively. The CRU is proposing to front load the revenues for PR6 as this would bring in funding potentially ahead of expenditure being incurred.

Table 31: Proposed Allowed Revenues for the DSO

€m's 2024 prices	2026	2027	2028	2029	2030
Opex (€m)	498	500	499	502	519
Depreciation (€m)	488	525	561	593	614
Return on assets in the RAB (€m)	318	330	345	363	377
Incentives (€m)	0	0	0	0	0
PR5 adjustments (€m)	-20	-20	-20	-20	-20
Revenue Requirement (€m)	**1,285**	**1,336**	**1,385**	**1,439**	**1,491**

Question(s):

13. Do you have any views on revenue profiling for PR6?

9 Customer Impact Summary

The impact of the PR6 distribution Draft Determination proposals, in terms of current estimates[33] of network charges and cost drivers are discussed in this section. The charges which would be expected to be relevant for an archetypical domestic electricity customer in the last tariff year entirely in PR6 (2029/30) are considered, along with the movement from the charges in the last tariff year entirely in PR5 (2024/25). Values are presented for two scenarios, both related to the Draft Determination proposals for distribution. The first is the baseline scenario and the second is a high scenario which includes the AIMF. For further details on this topic, including background, definitions, assumptions, other scenarios, non-domestic examples and further figures please refer to the Price Review Six Impact Analysis Note (CRU202591).

Table 32: Draft Determination Proposals: Domestic Customer Distribution Impact (Nominal Values)

Scenario	2024-25 (€)	2029-30 (€)	Change (€)	Change (%)
Baseline	250	305	+54	+22%
High		337	+87	+35%

In 2029/30 an archetypical domestic customer's electricity supplier is estimated to be charged €305 (baseline scenario) or €337 (high scenario) in charges relating to the distribution network for that customer[34]. This is via the DUoS charges, which collect revenues for the DSO. This is an increase of €54 (baseline scenario) or an increase of €87 (high scenario) from the comparable charge in 2024/25.

The main drivers of the high scenario +€87 increase (from 2024/25 to 2029/30) are the estimated increase in costs relating to delivering decarbonised electricity (+€46) and secure and resilient networks and supplies (+€36); these factors are partially offset by an estimated reduction in returns (-€28) and depreciation (-€4), relative to the last year of PR5.

Comparing the Draft Determination scenarios against company ask scenarios (baseline and full ask scenarios as relevant), the estimated 2029/30 distribution charges (relating to an

[33] The CRU will continue to refine and assess the consumer impact modelling for the Final Determination.
[34] Suppliers determine what level of these charges to either absorb or to pass on to their customers through their billing.

archetypical domestic customer) are €55 lower in the baseline scenario and €35 lower in the high scenario.

10 Conclusion and Next Steps

This paper, together with the supporting documents published alongside it, has outlined the CRU's proposals on the revenue that the DSO should be allowed to collect from its customers over the 2026 to 2030 period.

The CRU currently proposes to allow total gross baseline expenditure of almost €7.7bn for the five-year period. The detailed proposals behind these expenditure allowances are detailed in the sections above. This has the potential to be €9.8bn of total allowance if the DSO can provide sufficient justification for those requests which requires additional information.

It should be noted that the DSO has submitted a large volume of material prior to the publication of this paper, which could not be reviewed without further delays to the process. The CRU and its advisors will review this material, any additional submissions made by the DSO and the responses to this consultation in developing the Final Determination for PR6.

The proposed regulatory framework for PR6 is discussed in the Regulatory framework paper which is published alongside this paper.

Interested parties are requested to provide comments on the above proposals as detailed in this paper by 17:00 on 11 September 2025.

We are seeking comments from members of the public, the industry, customers and all interested parties on proposals put forward in this paper. These include the proposed operational expenditure allowance, and capital expenditure allowance over the PR6 period. The CRU is also seeking stakeholders' views on the areas requiring further information as applied to the DSO's revenues request and the proposed regulatory framework. Responses will assist and inform the CRU in reaching its final decision on the DSO's revenue allowance for the PR6 period. Consultation questions are listed in Appendix 1 below.

Following consideration of all responses received, the CRU intends to publish a decision on this matter before the beginning of the PR6 period.

Appendix 1 – List of Draft Determination Consultation Questions

Questions:

1. What are your views on the DSO's PR5 outturn capex, and the CRU's proposed Draft Determination ex post PR5 capex allowance?
2. What are your views on the DSO's PR5 outturn opex, and the CRU proposed Draft Determination ex post PR5 opex allowance?
3. Do you have any comments or views on any of the proposals set out in Section 3?
4. What are your views on the DSO's PR6 Capex request and the CRU's proposed Draft Determination?
5. What are your views on the DSO's PR6 Opex request and the CRU's proposed Draft Determination?
6. What are your views on the CRU's areas of additional information as applied to the DSO's baseline allowances?
7. Do you have any comments or views on any of the proposals set out in Section 4?
8. What are your views on the CRU's review of ESBN's asset lives proposals?
9. Do you have any comments or views on any of the proposals set out in Section 5?
10. What are your views on the proposed methodology for estimating the cost of capital?
11. Do you have any comments or views on the proposed estimates for the WACC parameters?
12. Do you have any views on the assessment of financeability?
13. Do you have any views on revenue profiling for PR6?

Appendix 2 – Summary of Responses to PR6 Strategy Paper

On 24 April 2024, the CRU published a Strategy Paper to inform and seek comments from consumers and relevant stakeholders on the approach proposed for PR6.

The CRU received a total of sixteen responses, all of which were non-confidential. The CRU analysed the Strategy Paper responses and considered the findings during the PR6 cost assessment phase. These enabled CRU to incorporate Strategy Paper feedback during the Network Companies workshops and therefore shaping the Draft Determination paper. These responses have been published in full on the CRU website and a summary of the key points are set out in Table 33 below.

Table 33 Summary of Responses to PR6 Strategy Paper

Area		Response Overview
1	Policy Developments	• One respondent pointed out the European Commission's recommendation in their assessment of Ireland's NECP to *"significantly raise the ambition of a share of renewable energy sources to at least 43% as a contribution to the Union's binding renewable energy target for 2030"*, which in their view necessitates further support and flexibility for the network companies. • One respondent pointed out that Section 17 of the Climate Action and Low Carbon Development Act (Amendment) 2021 places an onus on CRU to take all reasonably practicable measures necessary to ensure compliance with a range of government targets including CAP[35].

2	Outcomes	• There was broad agreement among respondents on the CRU's proposed outcomes for PR6.
		• One respondent suggested that outcomes should have specific dates and targets.
		• On Secure and resilient networks and supplies:
		  ○ One respondent commented that Ireland's energy supply should be sustainable, secure and cost efficient.
		• On decarbonised electricity:
		  ○ One respondent noted that carbon budgets require Ireland to reach a level of RES-E greater than 80% by 2030 or shortly thereafter.
		  ○ One respondent commented that this should be done both cost effectively and mindful of cost of electricity in competitors' locations.
		• On Empowered customers:
		  ○ One respondent noted that flexible consumers are excluded from participation in the Irish balancing market because TSO systems cannot issue dispatch instruction to flexible consumers.
		• One respondent commented that achieving these outcomes would require a complete transformation of the electricity system.

3	Objectives	• There was broad agreement among respondents on the CRU's proposed outcomes for PR6.

[35] Climate Action and Low Carbon Development (Amendment) Act 2021 – Section 17

- One respondent suggested that objectives need to be flexible, with measured real-time outcomes year on year during the price control period.
- Five respondents suggested that the network companies are given adequate resources in order to deliver on the objectives of PR6, particularly in delivering infrastructure at pace.
- On delivering infrastructure at pace:
    - Four respondents stressed that dispatch down costs must be a focus for PR6 to ensure that grid investment can realise reduction in constraints.
    - One responded sought to understand how the CRU will review and track progress of the business plans.
    - One respondent stressed that it is vital that network companies have the ability to find new solutions to deliver network infrastructure, such as through partnerships or an extension of the third-party network delivery framework.
    - One respondent sought clarity in the setting of targets and ambitions as to how Ireland will ensure compliance with the revised timescales under the Renewable Energy Directive for the connection (including permitting) of new energy infrastructure.
    - One respondent sought clarity on how projects are progressed through the TSO’s six step grid development process.
- On the Enhance system efficiency objective:
    - One respondent stated that PR6 must require a comprehensive and holistic delivery roadmap of all of EirGrid’s projects underway that will facilitate efficiency and optimisation of renewables, and that, where applicable, there is transparency and certainty in procurement.
    - One respondent urged the CRU to consider within its workplans and strategic planning how and when critical decisions (e.g. shared MEC behind 1 connection point, improved SEM-GB trading) which could impact on the network companies’ ability to ensure the optimised and efficient system operation can be developed.
- On the Ensure compliance with security of supply standards objective:
    - One respondent suggested that PR6 must take steps to consider the conclusions of the McCarthy report.
    - One respondent commented that timely delivery of all projects is crucial in establishing the security of supply required to ensure value delivery to the consumer who will be asked to meet the capital requirements through their bills.
    - One respondent posed that short-term costs of security of supply could be better utilised in grid infrastructure investment to leave a longer-term benefit to end consumers and increase investor confidence.
- One respondent suggested a further objective for PR6 on developing the organisational capacity of the network companies in order to deliver on ambitious decarbonisation plans beyond PR6.
- On the objective to Drive smarter, flexible, more digitally enabled networks and energy system:
    - One respondent commented that reductions in system wide carbon emissions should be the primary focus of any charging regime as part of the delivery of demand flexibility and CAP targets.
    - One respondent said that a range of renewable and complimentary technologies will be essential to Ireland meeting the 2030 RES-E targets and beyond, including both hybrid and storage projects, as well as various renewable technologies.
    - One respondent would like to see explicit recognition in PR6 for the ability of all forms of flexibility to delay or replace the need for new network when optimally sited behind a network constraint.
    - One respondent said that It should be possible to get information on network capacity and grid assets such as substation layouts

		and spare bay availability, along with comments on a grid route at an early stage well in advance of a project applying for planning.

4	Approach to Delivery	• There was broad support from respondents for the proposed approach to delivery.
		• On Flexibility:
		    ○ One respondent commented that network operators must be enabled to deploy resources flexibly where delays occur, such that delays to one programme of works do not directly impact others.
		• On the whole-of-system approach:
		    ○ One respondent commented that there needs to be a focus on measuring how decarbonisation can be delivered at least cost as part of the approach.
		• On Leveraging data and digitalisation:
		    ○ One respondent suggested that all reports issued by network companies include the provision of data in accessible and digital formats.
		• On Efficiency and justification of costs:
		    ○ One respondent stressed that the potential for commodity price related spikes to occur once again in the future needs to be forefront in the mind of any cost-benefit analysis of delivering new grid infrastructure.

5	Challenges and Opportunities	• One respondent noted that acquiring planning permission in relation to the sizeable pipeline of network infrastructure was not specifically outlined.
6	Regulatory Framework	• Two respondents supported the move beginning in PR5 towards a more output-based Price Review. • One respondent supported a review of the AIF ahead of PR6 to ensure that agility is prioritised. • One respondent suggested that regulatory framework is supportive whether through the appropriate use of uncertainty mechanism or in setting a WACC which will attract the necessary investment into the sector. • One respondent commented that an effective response to supply chain costs and challenges by the Government, the CRU and the wider sector is required to maintain the pace and reduce the costs of decarbonisation.
7	Incentives and Monitoring	• Four respondents suggested that the network companies are properly incentivised to reduce dispatch down levels, and that any proposals in this space are properly consulted upon. • Two respondents supported incentivizing Key Performance Indicators (KPIs) for delivery of additional grid capacity. • One respondent supported the CRU's intention to build on the regime adopted in PR5 for PR6, to ensure greater transparency and enhanced reporting around delivery of outcomes in terms that customers can meaningfully engage with. • One respondent suggested that CRU considers placing a proportion of PIs earned into a long-term account, payable only on full delivery of critical path projects and successful adherence to timelines. • One respondent recommended an increased focus and potentially changes in PR6 to the incentive/penalty structures if progress is not delivered within the PR5 period. • On the TSO/DSO coordination incentive, one respondent sought to understand how this can be further incentivised in a more equitable fashion to deliver new and upgraded transmission infrastructure. • One respondent supports the continuation of the cost and PI framework of output-based incentives in support of the Price Review objectives. It is their view that an output-based incentive should also be of benefit to consumers. • One respondent suggested an additional transparency incentive/penalty mechanism to motivate clear and transparent delivery plans and procedures.

		• One respondent suggested that the monitoring and reporting regime needs to strike the right balance between transparency of spending and delivery for the CRU and customers, while allowing the transmission utilities the space to focus on transmission system delivery. • One respondent stated that the impact of NEDS on the overall incentives of the network operators must be considered.

8	Miscellaneous	• Several comments were made in relation to expectations of the network companies' business plans:
		  ○ One respondent stressed that there needs to be clear planning, transparency and evidence-based assessments as a standard requirement for each of the plans being submitted.
		  ○ One respondent suggested that network companies should lay out their forecasting assumptions and scenarios that underpin their business plans in respect of the growth in electric heat, domestic and industrial, as well as electric transport with the wider gains being considered.
		  ○ One respondent suggested that business plans address:
		    ▪ Private wires
		    ▪ Connection delivery
		    ▪ Delivery of firm access
		    ▪ TUoS reform for refurbishment
		    ▪ Repowering and retention of existing sites for further development
		    ▪ Transparency of EirGrid market activities
		    ▪ Delivery of fully optimal participation of batteries
		    ▪ Implementation of hybrid connections
		    ▪ Facilitation of data centres
		• Five respondents want to see reform of the existing TUoS and DUoS tariff structures.
		  ○ One of the respondents suggested that reforms are clear, dependable and give a long-term cost signal.
		  ○ One respondent suggested that tariffs could focus more on SNSP than on day/night trends. They also suggested that they could be reviewed to analyse what mechanism in the structure can be reformed to allow for improved expansion of electrification.
		  ○ One respondent said that the tariffs need to be reformed in order to enable meeting various CAP decarbonisation targets.
		  ○ One respondent pointed out that the PR6 project has the potential to worsen the uncompetitive cost of electricity in Ireland, and that the phase and structure the components of electricity charges other than input costs should be adjusted to combat this.
		  ○ One respondent wants this to include a review of the application of pass-through costs, its price ratio in comparison to fossil fuels and how reform could support meeting CAP targets.
		• One respondent stressed that costs of operating and maintaining the overall networks do not become excessive and place an undue burden on customers.

Appendix 3 – Asset Lives Applied to Distribution Assets

Table 34: Assets Lives Applied to DSO Assets

Asset	Pre PR1	PR1	PR2	PR5
110kV networks assets	30	40	45	45
HV/MV/LV network assets	25			
IT	5	5	5 or 7	5 or 7
Office equipment	10	10	10	10
Fixtures & fittings	5	5	5	5
SCADA telecoms	15	15	15	15
Vehicles	7	7	7	7
Premises	50	50	50	50
Tools	5	5	5	5
Telecoms	15	10	10	10
Customer Contributions	45	45	45	45
Smart Metering				10
Protection				15
Continuity				15
System Control				10
Secondary Assets				10

For the initial revenue control period covering 2001 to 2005 (PR1) an asset life of 40 years was applied to network assets by the CRU. When setting the revenue control period for 2006 to 2020, the CRU decided that network assets contained in the RAB should be depreciated over an average lifetime of 45 years. The other asset lives were not changed when moving between periods.

Regarding the change from 40 to 45 year asset lives for the network assets, the PR2 decision paper noted that internationally in recent years there has been a general trend towards extending the lifetimes of electricity distribution assets. This is based on the experience of efficient network operators, who have found that equipment that is properly specified, installed and maintained will last longer than had previously been assumed. Performance of older assets is generally adequate, not least due to the modest pace of technological advance in electricity distribution, and the risks of purely age-related failure are considered to be low. In addition, condition monitoring has replaced age-based techniques in determining effective asset lifetimes.

The CRU decided that network assets contained in the RAB should be depreciated over an average lifetime of 45 years. Changes in an asset's life should be implemented in accordance with Section 5. The CRU sees no reason to change this treatment for the 2026 to 2030 period.

Appendix 4 – Valuation of the Regulatory Asset Base

The approach to valuing the assets within the RAB is also an important decision within the revenue control process.

The CRU proposes to continue to use its current approach for valuation of the RAB through into the PR4 period. This has become established practice during the first three review periods. The CRU considers that this approach remains appropriate and furthermore has the benefit of maintaining regulatory certainty for PR4.

The CRU decided for the initial price review (PR1) that the DSO's RAB would be valued using a replacement cost approach for the period 2001 to 2005. It was subsequently decided that the approach would be continued for the PR2 and PR3 periods.

While it is recognised that there are advantages and disadvantages associated with each methodology, the CRU selected, and continues to use, the replacement cost approach as it is more likely to result in the correct level of network investment.

As documented in previous Price Reviews, there are a number of variations of replacement cost that could be used. The CRU uses the acquisition cost, indexed with inflation, as a proxy for the replacement cost.

Background

The core issue regarding the valuation of the DSO's RAB is whether the RAB should reflect the value of the assets now (replacement value) or when they were built (acquisition cost). A number of variations on these approaches are outlined below. The advantages and disadvantages of each were set out in PR5 and still hold true.

Acquisition cost

Assets are valued at their original cost of construction/acquisition. The value of assets are not indexed for inflation nor is their value linked to the cost of replacement.

Replacement cost

Assets are valued at what it would cost to replace existing assets. There are two approaches to replacement cost:

- indexing the acquisition cost of the assets; and

- revaluing the asset based using a modern equivalent asset (MEA) approach.

Replacement cost less stranded assets

This is as per replacement cost (above) but those assets that are not utilised in the current system would be excluded. Effectively, this would be the cost of building a replacement system for the currently used system.

Deprival value

The assets would be valued at the lower of their replacement cost or economic value (in the event that they could not be replaced).