

LCoS assessment for the LDES revenue floor bid limit

A report to EirGrid plc

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1 Background to the LDES service provision and procurement mechanism

The Long Duration Energy Storage (LDES) service is a service being introduced by EirGrid to help manage rising volumes of variable renewable generation, reduce dispatch down, and contribute to secure operation of a system moving towards 100% non-synchronous penetration. In line with Action 6 of the Department of Climate, Energy and the Environment's Electricity Storage Policy Framework, the service targets assets with a minimum 4-hour duration capable of importing and exporting electricity to and from the grid.

Operationally, the service is built around a Trading Envelope (TE) — a dynamic, time-based set of maximum import/export limits expected to be issued at 10:00 D-1. This is intended to prevent LDES units from charging during periods of system tightness and/or discharging during curtailment/constraint events. Otherwise, LDES assets will be free to trade across all SEM markets.

The procurement process will take the form of a technology-neutral, service-based tender for up to 500 MW of LDES assets with a minimum 4-hour duration. First, there will be a pass/fail qualification stage followed by a tender stage. Projects will need to have a Connection Offer to qualify, and a Connection Agreement to participate in the tender.

Projects will submit bids that will be assessed on three criteria: a) cost (50%); b) impact on dispatch down and energy arbitrage availability based on ECP 2.5 modelling (30%); and c) connection method (20%). Shortlisted projects will then progress to a BAFO stage that includes a grid connection deliverability assessment.

Successful projects will be awarded 10-year contracts. The procurement process is expected to commence in 2027, with delivery timelines designed to accommodate both new LDES projects and projects that are already under development and could benefit from securing long-term contractual support through this procurement process.

The operational incentive instrument relies on a ‘revenue floor’, which is the outcome of the tender process and based on the bids from the successful projects, and revenue sharing arrangements for any income above this floor. The asset owner/operator will retain 70% of the revenues above the floor and the remainder 30% will be returned to consumers. The revenue compared to the ‘floor’ is the gross revenue, and the reconciliation will take place annually ex-post. The rationale for the ‘floor’ is twofold:

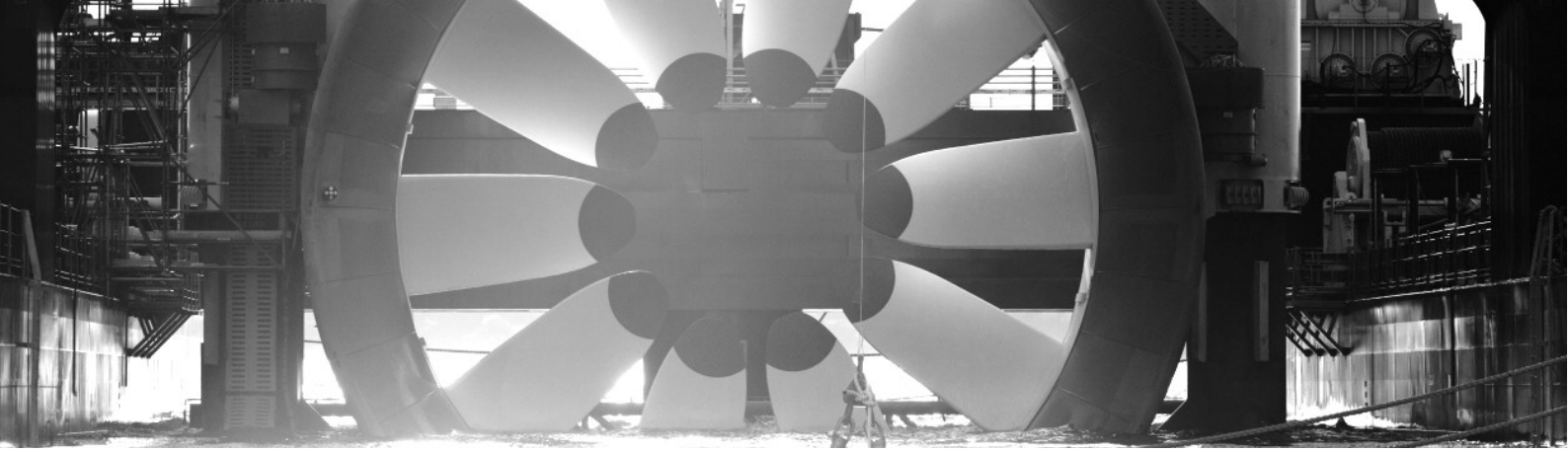
— the Trading Envelope may, at times, restrict contracted assets market operation, foregoing some ‘unconstrained’ energy arbitrage opportunities in order to deliver value to the system on a ‘constrained’ basis; and
— a floor being needed as a *quid pro quo* to protect investors from revenue uncertainty, as current SEM energy, capacity and system service revenues under a trading envelope

approach may not suffice to deliver investment in LDES. Revenue certainty was also highlighted in the responses to the 2023 Call for Evidence and the 2025 Consultation on the Procurement Approach.

At the same time, the use of a revenue floor bid limit and the 70:30 revenue sharing helps protect consumers. The 'floor-and-share' design is intended to strike a balance between investment certainty for LDES developers (who need bankable revenues to finance capital-intensive assets) and value for money for consumers, in a market where the TSO cannot own or directly operate storage under EU law and must therefore rely on market-compatible mechanisms to secure the required system services.

The presence of a revenue floor and wider contractual arrangements for the LDES assets can have a strong impact on asset operation. If not meticulously designed, this may result in inefficient dispatch. A revenue floor that is too high has an obvious drawback – the asset operator may have limited incentive to actively participate in the different markets if it is challenging to capture revenues that exceed the floor and/or if it was to retain only a very small part of the income above the floor. To avoid this, EirGrid has already proposed a maximum revenue floor at, or below, the expected LCoS for the relevant assets. On the other hand, a revenue floor that is too low may fail to derisk the LDES projects.

The focus of this paper is to give clarity to industry on how the revenue floor bid limit is set, what the considerations are, and what it means for their project – i.e. what is the value of the relevant bid limit for their type of project.



2 Choice of reference technologies and LCoS definition

2.1 Choice of reference technology

There are various LDES technologies, ranging from mature technologies that have been widely deployed over the years, such as pumped hydro, to emerging ones that are not yet commercially ready. For the purposes of this initial procurement of up to 500MW of LDES service provision the process will contract LDES service provision only from experienced developers and from technologies that meet the minimum technical criteria, as set out in Exhibit 2.1.

This paper is focused on assessing technologies that are:

— established with proven technical and commercial performance; and

— can meet the below technical criteria and are effectively eligible to participate in the upcoming LDES tender.

A project must have a Connection Agreement to be eligible to participate in the LDES procurement process with the current connection queue consisting almost exclusively of Li-Ion battery projects. Given this requirement, our analysis focuses **on Li-Ion battery costs and the relevant parameters that can help inform the LCoS for Li-Ion batteries**.

The methodology and the cost assessment can be updated and expanded in the future to cover additional LDES technologies. In any case, the LDES system service and procurement are technology neutral. Should another technology be in a position to meet the technical eligibility criteria and, at the same time, be cost competitive, basing the revenue floor bid limit on Li-Ion batteries costs should not be a barrier.

Exhibit 2.1 – Technical eligibility criteria

Criteria	Unit
Duration	The storage asset must be capable of discharging electricity continuously at its nameplate power capacity rating for the contracted MWh duration (**minimum 4 hours**) in line with its contracted MEC, and charging for the contracted duration continuously at its nameplate power rating in line with its contracted MIC, sustained over the full contract term. There is no maximum duration.
MEC/MIC ratio	MEC = MIC
Minimum capacity	20MW
Maximum capacity	100MW
Minimum Round-trip efficiency	75%
Asset Health Management	The asset must be able to deliver its full contracted power and duration over the full duration of the contract; this will be verified on an annual basis. This will be verified either through operational delivery and reporting, or, where needed, through performance testing. Degradation is the asset owner's responsibility and can be managed through oversizing, augmentation, replacement, etc. Any shortfalls outside the agreed tolerance can trigger reduced/withheld revenue floor payments and, ultimately, contract termination.
Grid connection	A Connection Offer and a Connection Agreement are required at Qualification stage and at the Tender stage respectively, together with a connection programme. During the BAFO stage, EirGrid assesses deliverability and determines a Target Energisation Date, which must be at least four months before the Target Go-Live Date to pass the deliverability criterion.
Planning permission	Final Grant of Planning Consents for both the Facility and the Grid Connection is required, together with Evidence of Land Owner Consents, a Key Map, and an AutoCAD of the Grid Infrastructure.
Deliverability	The target go-live date is expected to be a set number of months from contract execution. Early delivery is incentivised with projects able to deliver the LDES service ahead of the target go-live date awarded a longer contract term.

2.2 LCoS definition

The Levelised Cost of Storage (LCoS) is defined as a cost per unit of capacity (EUR/kW-year), equal to the annualised (discounted) capital costs plus fixed operating costs, both divided by the asset's average available capacity. A variable cost component that scales with the assumed load factor and the number of hours in the year can also be included. The energy production captured through the load factor is an assumption when it comes to a dispatchable asset, and it is good practice to also state the assumed number of cycles and resulting production.

2.2.1 LCoS formula and parameters

The LCoS can be estimated based on the equation shown in Exhibit 2.2, where:

- Avai: Annual average availability (%)
- BT: Build time (years)
- Capex: Capital expenditure (EUR/kW)
- FT: Financial lifetime (years)
- HR: Hurdle rate (%)

— LF: Load factor (% of nameplate capacity)
— $Opex_F$: Fixed operating expenditure (EUR/kW-year)
— $Opex_V$: Variable operational expenditure (EUR/MWh)

Exhibit 2.2 – LCoS formula (EUR/kW-yr)

$$LCoS = \frac{\sum_{-BT+1}^{0} \frac{Capex}{BT*(1+HR)^t}}{Avai * \sum_{1}^{FT} \frac{1}{(1+HR)^t}} + \frac{Opex_F}{Avai} + Opex_V * LF * \frac{8760}{1000}$$

2.2.2 'Delivered Energy' LCoS

The Delivered Energy LCoS (DE LCoS) is expressed in EUR/MWh and can help present the cost of delivered energy on a like-for-like basis across different storage durations and asset configurations. We have chosen to exclude the cost of purchasing energy to charge the asset (or one could view this as charging always at price of zero). The formula can be seen in Exhibit 2.3, where:

— Avai: Annual average availability (%)
— BT: Build time (years)
— Capex: Capital expenditure (EUR/kW)
— FT: Financial lifetime (years)
— HR: Hurdle rate (%)
— LF: Load factor (% of nameplate capacity)
— $Opex_F$: Fixed operating expenditure (EUR/kW-year)
— $Opex_V$: Variable operational expenditures (EUR/MWh)

Exhibit 2.3 – DE LCoS formula (EUR/MWh)

$$DE\,LCoS = \frac{\sum_{-BT+1}^{0} \frac{Capex}{BT*(1+HR)^t} * 1000}{Avai * \sum_{1}^{FT} \frac{LF*8760}{(1+HR)^t}} + \frac{Opex_F * 1000}{Avai*LF*8760} + Opex_V$$

2.3 Conventions

The analysis presented in this report has been prepared based on information publicly available as of late-June 2026. Unless otherwise indicated, monetary values are expressed in real Jan 2025 money terms. For simplicity, values are sometimes calculated as averages, approximations or groupings without loss of accuracy for the purposes of the analysis. Unless otherwise stated, the source of all tables and figures is AFRY.



3 Cost and economic parameter benchmarks

The cost of utility-scale Li-Ion storage is shaped by both global and local factors. Battery pack prices are influenced by global supply chains, cost of raw materials and competition between manufacturers. Grid connection costs, on the other hand, are specific to the Irish system and depend on the connection type, project location and network works required for each asset. We, therefore, combine global benchmarks (including evidence from other markets), Irish-specific inputs and evidence from comparable support mechanisms in other markets.

Li-Ion battery component costs have fallen rapidly in recent years, and observed costs have increasingly aligned with lower-cost forecasts from 2023 onwards. Bloomberg NEF reported an 8% fall in its any-use weighted average Li-Ion battery pack price between 2024 and December 2025[1].

3.1 Experience with Li-Ion cost determinations in other markets

3.1.1 Italy's MACSE

The Italian TSO, Terna, has already developed MACSE, a market framework for long-term contract storage procurement. In its 2025 Reference Technologies study[2], Terna published benchmark costs for Li-Ion batteries, covering capex, opex and CoNE (Cost of New Entry). The respective values and the equivalent cost in EUR/kW-year are shown in Exhibit 3.1.

[1] BloombergNEF (2025). Battery storage system prices continue to fall sharply (battery storage market benchmark). Access link: Energy Storage News article reporting BloombergNEF findings.
[2] Terna (2025). Study on Reference Technologies for Electricity Storage. Institution: Terna S.p.A. Access link: Terna Study on Reference Technologies for Electricity Storage.

Exhibit 3.1 – MACSE cost and economic assumptions for 4 and 8-hour Li-Ion BESS, 2025

MACSE published benchmark costs ahead of its 2025 auction.

Parameter	Unit	4-HR	8-HR
Investment costs	EUR/kWh	191-282	189-267
Oversizing	% of investment	12%	12%
Annual fixed costs	EUR/kWh-yr	2.3 – 7.0	2.1 – 6.3
WACC*	%	9%	9%
Build time	years	1	2
Delivery period	years	15	15
CoNE	EUR/kWh-yr	31-50	31-47
CoNE equivalent in EUR/kW-yr		124-200	248-376

Notes: Values are presented in nominal money terms
WACC: Weighted Average Cost of Capital
Source: Terna (2025)

Terna held the first MACSE auction on 30 September 2025, procuring the full 10 GWh of storage capacity sought across four zones in Southern Italy and the islands (Central-South, South and Calabria, Sicily and Sardinia). The auction was heavily oversubscribed, with bids exceeding demand by more than four times, and cleared at a weighted average price of 13.0 EUR/kWh-year – well below the 37.0 EUR/kWh-year reserve premium, and below the CoNE-equivalent range shown in the table above.

Zonal clearing prices ranged from 12.1 EUR/kWh-year in South and Calabria to 15.8 EUR/kWh-year in Sicily. Awarded projects are Li-ion BESS with an average duration of approximately 7 hours, reflecting developers' preference to minimise capex per unit of contracted capacity given the 15-year guaranteed revenue period, and are expected to enter operation in 2028.

3.1.2 Western Australia's Reserve Capacity Mechanism

Battery storage is now the benchmark technology for capacity procurement in the South West Interconnected System (SWIS) under Western Australia's Reserve Capacity Mechanism (RCM). A benchmark payment is calculated and published annually by the Economic Regulation Authority (ERA)[3]. Under the current methodology, ERA estimates the costs of constructing, connecting, operating, and financing a 'typical' battery asset and uses these assumptions to determine the Benchmark Reserve Capacity Price (BRCP). The price is then used by AEMO (Australian Energy Market Operator) in determining capacity payments within the market.

The latest official determination is based on a benchmark 200 MW / 1,200 MWh (6-hour) Li-Ion BESS with a an assumed 15-year economic life. The resulting BRCP is AUD 488.5/kW-yr, equivalent to 296.6 EUR/kW-yr.

[3] Economic Regulation Authority (2026). Benchmark Reserve Capacity Price (BRCP) Determination for the 2028/29 Capacity Year. Institution: Economic Regulation Authority (Western Australia). Access link: BRCP [aemo.com.au].

3.1.3 GB's LDES Cap-and-Floor scheme

Great Britain's LDES scheme is an example of a revenue floor instrument. Under this scheme, projects will receive a minimum revenue floor if market revenues fall below an agreed threshold and share a portion of revenues above a predefined cap with consumers. The GB mechanism does not rely on a published technology benchmark. Instead, cap and floor levels are determined through a project-specific financial assessment that considers capex, opex, financing costs, construction costs and target rates of return. The scheme therefore provides a useful methodological benchmark for designing a revenue floor, but it does not provide a specific published value to use for reference.

Ofgem defines LDES specifically as storage with a discharge duration of 8 hours or more. In its most recent Window 1 outcome, Ofgem provisionally selected 16 projects out of 73 eligible applicants, totalling approximately 7.65 GW and 136.9 GWh, with durations ranging from 8 to 22 hours – notably longer than the 4 to 12-hour range considered in this paper for the Irish LDES scheme.

The floor itself is set using either an administrative floor, based on a notional cost of debt, or an Actual Cost of Debt (ACOD) floor where the project is project-financed. Ofgem has also increased the share above the cap from 10% to 30%, meaning developers retain 70% of revenues above the cap – a split that mirrors the 70/30 arrangement already proposed for the Irish LDES scheme (see Section 5). Indexation under the GB scheme is based on CPIH rather than a fixed inflation assumption, in contrast with the flat 2% inflation rate applied in this paper's hurdle rate methodology[4].

Ofgem sets a target rate of return as a fixed parameter for the scheme, although projects may request a higher rate with strong justification, which Ofgem then assesses on a case-by-case basis. This provides a degree of flexibility not currently reflected in this paper's hurdle-rate build-up methodology.

3.2 Public benchmark values

We have used the following sources:

- NLR (formerly NREL) 2023[5] & 2025[6];
  - the National Laboratory of the Rockies conducts research to advance real-world applications to advance energy technologies that lower costs, strengthen security, and ensure abundant energy. NLR published an annual view of LCoS for technologies including Li-ion batteries. In its 2025 European Resource Adequacy Assessment (ERAA) the European Network of Transmission System Operators (ENTSOE) used NLR assumptions as a source for costs for 4-hour utility-scale batteries[7].

[4] The indexation applied in this paper is an assumption and the approach to be used in the scheme is yet to be determined.
[5] NLR, formerly NREL (2023). Annual Technology Baseline (ATB) 2023: Utility-Scale Battery Storage Scaling Relationships. Access link: https://atb.nrel.gov/electricity/2023/utility-scale_battery_storage.
[6] Cole, W., Ramasamy, V. & Turan, M. (2025). Cost Projections for Utility-Scale Battery Storage: 2025 Update (NLR/TP-6A40-93281). Institution: NLR, formerly NREL. Access link: NLR Battery Storage Cost Projections 2025. [docs.nlr.gov].
[7] European Network of Transmission System Operators for Electricity (ENTSO-E) (2025). European Resource Adequacy Assessment (ERAA) 2025. Access link: European Resource Adequacy Assessment 2025.

- these reports act as a key bottom-up benchmark for utility-scale Li-Ion battery storage, including a detailed capex breakdown in battery equipment, power conversion systems, balance of system and EPC, which helps distinguish which parts of the capex are influenced by equipment costs and which are linked to installation and project delivery;
- IEA World Energy Outlook 2025[8];
  - the IEA cost reference is not as complete as the NLR version as it excludes some delivery components;
- BNEF's 2025 benchmark[9];
  - BNEF tends to be the most up-to-date market reference for battery equipment and turnkey BESS pricing, making it particularly important with battery pack costs having declined materially in recent years, supported by cell manufacturing overcapacity, stronger supplier competition, higher energy density and the shift towards lower-cost LFP chemistries;
- Lazard's 2025 LCOE[10];
  - this report focuses on the US market and provides a range of costs for projects.

Grid connection costs are location specific, and depend on the network conditions, project location and the specific connection requirements for each asset. We, therefore, use information that is representative of Ireland. However, we define a figure that is typical for Ireland but may not necessarily reflect the specific conditions of each asset.

[8] International Energy Agency (2025). World Energy Outlook 2025. Access link: World Energy Outlook 2025.
[9] BloombergNEF (2025).
[10] Lazard (2025). Levelized Cost of Energy+ (Version 18.0) and Levelized Cost of Storage (Version 10.0). Access link: Lazard LCOE+ June 2025. [lazard.com].



4 LCoS determination

For each cost and economic parameter used in the LCoS calculation, we present a Base Case, alongside a High and a Low scenario. The Base Case reflects our best view of the relevant parameter, informed by the public benchmark sources set out above and our own market intelligence. The High and Low scenarios are constructed by applying a symmetric variation to the Base Case: a 25% premium is applied to the Base Case value to define the High case, and a 25% discount is applied in the Low case.

This approach is intended to provide a reasonable and consistent range around our central view, broadly capturing the spread of values generally observed across the public sources reviewed in Section 3.2, rather than representing the specific high or low estimate from any sole source.

For the hurdle rate, the approach is considering in the High case a premium of +2pp, as it operates under the assumption of a more dynamic economic context; on the other hand, the Low case considers a discount of -2pp to reflect a more stagnant economic context.

4.1 Capital expenditure

We have used the above sources for estimating the Li-Ion capex. NLR provides the 'basis' for our bottom-up capex view, including power conversion systems, balance of system and EPC, with the battery pack cost updated based on the BNEF benchmark. The IEA and Lazard figures are used as comparators.

Additionally, for grid connection capex, we expect connection costs in Ireland to differ from international benchmark values because they are driven by local system conditions, being generally higher than most continental European markets.

4.1.1 Capex stack and scaling for different durations

We have built the capex 'stack' from the following components:

- **Battery pack:** the core battery storage component – this is mainly driven by international manufacturing capacity, chemistry trends and supplier competition;
- **Battery oversizing:** the additional battery capacity acquired by operators to manage degradation over the life of the asset, while delivering the contracted power for the contracted duration;
- **BoS structural:** physical balance-of-system costs, such as foundations, containers, roofing and other structural requirements;
- **BoS electrical:** electrical balance-of-system costs outside the battery pack and power conversion system, including cabling and related electrical equipment;

— **Grid connection:** the cost of connecting the asset to the Irish grid, based on Irish-specific project information because it depends on connection type, local network conditions and project-specific works; and
— **EPC:** engineering, procurement and construction costs required to bring the asset into operation;

For the different storage durations, we apply scaling factors based on the cost relationship in the 2022 ATB utility-scale battery storage dataset. ATB provides bottom-up installed cost estimates for Li-ion BESS at different durations, including 2-, 4-, 6-, 8- and 10-hour systems. We then use this relationship to scale the relevant technology-led capex components from the 4-hour reference case to assets with different storage durations.

4.1.2 Capex benchmark

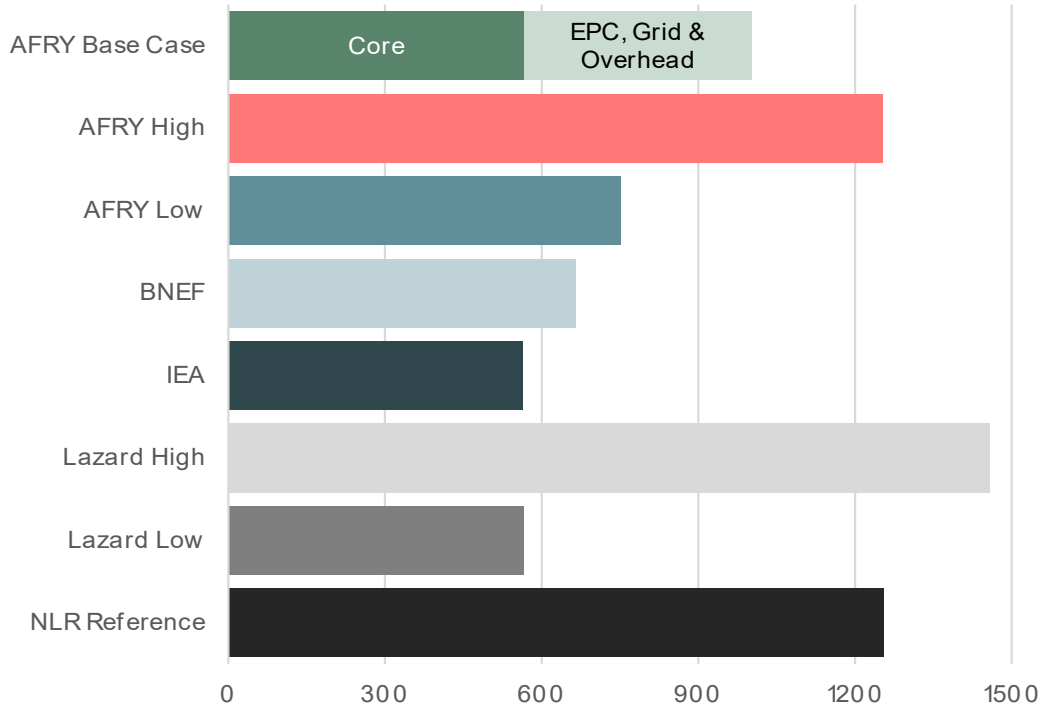
Our bottom-up Li-Ion capex estimate sits within a reasonable range of recent public evidence:

— NLR (2025) is at the top end of the range – this is predominantly because of battery pack cost assumptions that are higher than what is currently observed in the market;
— Lazard (2025), on the other hand, gives a much broader range to help capture a wider set of project circumstances, including differences in procurement route, location, contracting strategy, tax treatment and developer assumptions; and
— IEA (2025) and BNEF (2025) are 'incomplete', focusing mostly on core components (battery pack and balance of system), and not reflecting the full installed cost of a unit.

The core capex items in the AFRY Base Case capex (battery pack, battery oversizing and balance of system) are comparable with the BNEF and IEA estimates. The AFRY total capex Base Case estimate is below the NLR and Lazard values because of more up-to-date and cheaper battery pack costs in our estimate. We also provide High and Low cases, to reflect a reasonable capex range of capex. The graphic comparison can be seen in Exhibit 4.1.

Exhibit 4.1 – CAPEX benchmark for a 4-hour battery deployed with COD 2024 - EUR/kW

AFRY's view is widely aligned with the ranges seen in public sources



Notes: AFRY values assume a 2025 COD capex view split between core battery costs versus grid connection, EPC and overheads. NLR (2025) reflects a full owner-cost view and is used as a conservative system-planning reference. Lazard (2025) presents a market range intended to reflect full owner costs. The IEA (2025) and BNEF (2025) provide equipment-led benchmarks and exclude grid connection, EPC and overheads.

4.1.3 Capex used in LCoS calculation

The table below sets out the capex used in the LCoS calculation, expressed in EUR/kW, for each storage duration and commercial operation date. The capex increases with duration as longer-duration assets require additional battery capacity and drops over time in line with technology-led component cost reductions over time.

Exhibit 4.2 – CAPEX assumptions for the LCoS calculation (EUR/kW)

Year	4-hour			6-hour			8-hour			12-hour		
	Base case	High	Low	Base case	High	Low	Base case	High	Low	Base case	High	Low
2025	1003	1254	752	1314	1643	986	1705	2132	1279	2160	2700	1620
2026	969	1211	726	1261	1576	946	1636	2046	1227	2042	2553	1532
2027	939	1174	704	1215	1519	912	1577	1971	1183	1942	2427	1456
2028	895	1118	671	1157	1446	867	1501	1876	1126	1851	2314	1388
2029	869	1087	652	1119	1399	839	1452	1815	1089	1771	2213	1328
2030	845	1056	633	1082	1353	812	1404	1755	1053	1696	2119	1272
2031	831	1038	623	1061	1327	796	1377	1722	1033	1652	2065	1239

Source: AFRY analysis based on public sources and market intelligence .

4.2 Opex

4.2.1 Opex build-up

The Opex represents the ongoing costs of maintaining and operating a storage asset each year, and can be divided into two categories:

— **fixed opex**: these are the annual avoidable fixed costs, incurred irrespective of asset operation (number of cycles, energy stored and injected to the grid, etc.), and includes:
  - routine operation and maintenance (O&M);
  - monitoring and software support;
  - planned inspections and servicing;
  - insurance;
  - land lease costs; and
  - reactive maintenance and certain component replacements where costs are not linked to asset usage;

— **variable opex**: costs that depend on asset utilisation, cycling, and energy throughput.

As part of these costs, we consider an augmentation component. Even though this is generally addressed by projects as a capex, for the purposes of our LCoS calculation, we assume this cost is incurred on an annual basis and is included in the opex. This can be split into two components:

— degradation due to aging that happens over time regardless of utilisation and is reflected within the fixed opex through replacement and augmentation allowances; and

— degradation due to cycling that depends on asset usage and is therefore treated as variable opex. This component is assumed to be paid continuously to maintain the battery's capacity at a constant level.

Replacement and augmentation costs are derived from the battery pack costs used in the capex assessment, reflecting the cost of future battery equipment required to maintain performance.

4.2.2 Opex benchmark

The chart below compares our opex assumption for a 4-hour Li-Ion BESS, including both fixed and variable opex expressed in €/kW-year, against external benchmarks.

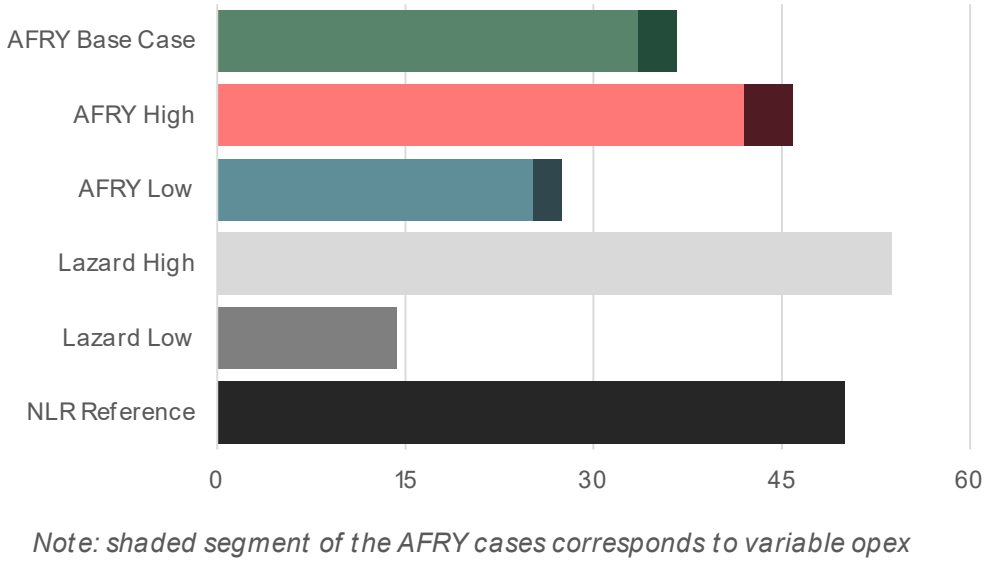
For comparison, NLR's fixed O&M benchmark is shown as a reference for recurring operating and maintenance costs, while Lazard's opex estimate has been converted to a

EUR/kW basis to enable a like-for-like comparison. As Lazard reports total operating costs rather than fixed O&M alone, its values provide a broader reference point.

Our opex (as presented in the chart below) reflects both the fixed costs of maintaining asset availability and the variable costs associated with battery cycling and degradation, providing a benchmark that is consistent with the LCoS assessment framework used in this study. We see that AFRY's Base case is somewhat in the mid-point versus the relevant benchmarks, while the High and Low cases provide coverage of the potential range of expenditures.

Exhibit 4.3 – OPEX benchmark for a 4-hour battery deployed with COD 2024 (EUR/kW-yr)

AFRY's view is widely aligned with the ranges seen in public sources



Notes: AFRY values assume a 2025 COD.

4.2.3 Opex input

Exhibit 4.4 contains the fixed opex inputs used in the LCoS calculation, while Exhibit 4.5 shows the variable opex values. Fixed opex is expressed in EUR/kW-year while variable opex is expressed in EUR/MWh.

Exhibit 4.4 – Fixed OPEX assumptions for the LCoS calculation (EUR/kW-yr)

Year	4-hour			6-hour			8-hour			12-hour		
	Base case	High	Low	Base case	High	Low	Base case	High	Low	Base case	High	Low
2025	34	42	25	46	57	34	57	71	43	66	83	50
2026	32	40	24	43	54	32	54	68	41	62	78	47
2027	31	38	23	41	51	31	51	64	39	59	74	44
2028	29	36	22	39	49	29	49	61	37	56	70	42
2029	28	35	21	38	47	28	47	59	35	54	67	40
2030	27	34	20	36	45	27	45	56	34	51	64	39
2031	26	33	20	35	44	26	44	55	33	50	62	37

Source: AFRY analysis based on public sources and market intelligence.

Exhibit 4.5 – Variable OPEX assumptions for the LCoS calculation (EUR/MWh)

Year	4-hour			6-hour			8-hour			12-hour		
	Base case	High	Low	Base case	High	Low	Base case	High	Low	Base case	High	Low
2025	2.1	2.6	1.6	2.0	2.5	1.5	2.0	2.4	1.5	1.9	2.4	1.4
2026	1.9	2.4	1.5	1.9	2.3	1.4	1.8	2.3	1.4	1.8	2.2	1.3
2027	1.8	2.3	1.4	1.7	2.2	1.3	1.7	2.1	1.3	1.6	2.1	1.2
2028	1.7	2.1	1.3	1.6	2.0	1.2	1.6	2.0	1.2	1.5	1.9	1.1
2029	1.6	2.0	1.2	1.5	1.9	1.1	1.5	1.8	1.1	1.4	1.8	1.1
2030	1.5	1.9	1.1	1.4	1.8	1.1	1.4	1.7	1.0	1.3	1.7	1.0
2031	1.4	1.8	1.1	1.4	1.7	1.0	1.3	1.6	1.0	1.3	1.6	1.0

Source: AFRY analysis based on public sources and market intelligence

4.3 Hurdle rate

4.3.1 Hurdle rate methodology

The hurdle rate represents the return required to finance an eligible LDES asset. It is used as a discount rate for the cash flows. We have estimated a hurdle rate with reference to Irish financing conditions, the asset risk profile and the proposed revenue floor arrangements.

The hurdle rate is calculated as a pre-tax, real WACC. The WACC combines the cost of debt and the cost of equity using the assumed project gearing. Debt costs reflect the risk-free rate and a debt margin for project-financed energy infrastructure. Equity costs reflect the risk-free rate, an equity premium and the risk associated with the technology and revenue model. The final value is expressed in real terms, consistent with the LCoS calculation.

Our approach relies on inputs from the framework developed by Aswath Damodaran[11] for estimating country and market risk premia, adapted to the financing characteristics of energy infrastructure assets. The risk-free rate is inferred from 30-year EUR swap rates, using Chatham Financial data, while the remaining debt, equity and risk-premium inputs are informed by our own market intelligence with respect to country and technology-specific financing conditions.

These inputs are used within the WACC framework and adjusted, where needed, to reflect the risk profile of eligible LDES assets and the proposed scheme. The presence of the revenue floor changes the risk profile of an LDES asset compared with a fully merchant project by reducing exposure to wholesale price volatility, dispatch volume risk and short-term system-services price movements for the revenues covered by the scheme.

A project supported by a revenue floor or similar long-term contract is assumed to carry lower risk than a fully merchant project as a material share of its revenues is stabilised over the contracted period. This improves cash flows predictability available to service debt and remunerate equity. Lenders and investors would, therefore, typically require a lower return than for an equivalent merchant asset, where revenues depend entirely on uncertain future market conditions. Some market risk remains for revenues beyond the floor and the post-

[11] Damodaran, A. (2026). Damodaran Online: Data page for Aswath Damodaran (country risk premiums, equity risk premiums, cost of capital estimates). Institution: New York University Stern School of Business. Access link: pages.stern.nyu.edu/~adamodar/

contract period. This means any hurdle rate adjustment is not equivalent to treating the asset as fully contracted, rather, reflects the extent to which the floor reduces downside revenue risk over the asset lifetime.

4.3.2 Formula and parameters of the hurdle rate

We calculate the hurdle rate as a real pre-tax WACC. It combines the cost of debt and the cost of equity according to the assumed gearing ratio. The relevant formula is shown in Exhibit 4.6.

Exhibit 4.6 – Hurdle rate formula (%)

$$\text{Hurdle rate} = \frac{1 + \text{Gearing} * WACC_D + (1 - \text{Gearing}) * WACC_E}{1 + INF} - 1$$

The cost of debt, $WACC_D$, starts from the risk-free rate and adds allowances for country risk, debt risk and market exposure The corresponding formula can be found in Exhibit 4.7. The cost of equity, $WACC_E$, uses the same risk-free rate and country-risk allowance, but adds the equity premium, development risk and market exposure before applying the tax adjustment, as shown in Exhibit 4.8. The two components are then weighted by the assumed gearing ratio.

Exhibit 4.7 – Cost of Debt (%)

$$WACC_D = RFR + CRP + DRP + MER$$

Exhibit 4.8 – Cost of Equity (%)

$$WACC_E = \frac{RFR + CRP + ERP + DEV + MER}{1 - TAX}$$

The parameters used in the different formulas are informed by our own view of Irish financing conditions, the risk profile of eligible LDES assets and the proposed revenue floor design. They cover the cost of debt and equity, inflation, country-specific risk, development risk, market exposure, the tax rate and achievable gearing.

- **Risk-free rate (RFR):** baseline return expected from a risk-free investment, used as the starting point for debt and equity return assumptions.
- **Country risk premium (CRP):** allowance for country-specific payment, credit or offtake risk, including payment delay or default risk.
- **Debt risk premium (DRP):** additional return required by lenders to reflect the credit and project risks associated with lending to an energy infrastructure asset.
- **Equity risk premium (ERP):** additional return required by equity investors to reflect the risks of providing equity capital to an LDES project.

— **Development risk (DVR):** allowance for risks during development and construction, including delays, cost overruns or delays to commercial operation.
— **Market exposure risk (MER):** allowance for uncertainty in future market revenues, particularly revenues not covered by the revenue floor or earned after the contracted period.
— **Inflation (INF):** expected rate of price inflation, used to convert between nominal and real return assumptions where required by the LCoS calculation.
— **Tax rate (TAX):** applicable corporate tax rate used in the pre-tax WACC calculation to adjust the equity return component.
— **Gearing ratio:** assumed proportion of debt and equity used to finance the asset, reflecting the level of debt that the project risk profile can support.

4.3.3 Hurdle rate input

Exhibit 4.9 shows the parameters used to calculate the hurdle rate in the Base Case. The cost of debt is built up from the risk-free rate, country risk premium, debt risk premium and market exposure risk, resulting in a nominal cost equal to 6.3%. The cost of equity applies the same risk-free rate and country risk premium, and adds the equity risk premium, development risk and market exposure risk, with the tax adjustment applied through the pre-tax WACC formula. This results in a pre-tax equity cost of 12.3%.

The debt and equity components are then combined using the assumed gearing ratio of 40% debt and 60% equity. The resulting nominal pre-tax WACC is converted into real terms using the assumed inflation rate of 2% per year[12].This gives a real pre-tax hurdle rate of 7.8%, which is applied in the LCoS calculation as the discount rate for relevant project cost cash flows.

Exhibit 4.9 – Hurdle rate parameters in the Base Case (%)

	RFR[13]	CRP[14]	DRP[15]	ERP[16]	DEV[17]	MER[18]	TAX[19]	Total
$WACC_D$	3.0%	0.8%	1.5%			1.0%		6.3%
$WACC_E$	3.0%	0.8%		4.0%	2.0%	1.0%	12.5%	12.3%
Gearing[20]								40.0%
Inflation[21]								2.0%
Hurdle rate								7.8%

[12] Based on the ECB long-term inflation target, European Central Bank (2025). Monetary policy strategy: Price stability. Institution: European Central Bank (ECB). Access link: ecb.europa.eu/mopo/strategy/pricestab
[13] Based on Chatham Financial (2026). European Interest Rate Data. Institution: Chatham Financial. Access link: cf.com/rates/europe. [Data viewed 19 June 2026]; value has been rounded to 3.0%.
[14] Damodaran, A. (2026).
[15] Damodaran, A. (2026).
[16] Damodaran, A. (2026).
[17] AFRY assumption.
[18] AFRY assumption.
[19] Damodaran, A. (2026).
[20] AFRY assumption.
[21] European Central Bank (2025).

As previously described, for the High case we consider a premium of +2pp in the hurdle rate, as it operates under the assumption of a more dynamics economic context; on the other hand, the Low considers a discount of -2pp to reflect a more stagnant economic context.

4.4 Technical characteristics

4.4.1 Duration

Most Li-Ion batteries currently connected in Ireland and elsewhere in Europe have durations of less than 4-hour, although more recent procurement processes, such as the GB LDES scheme, are indicating longer duration Li-Ion units will become more prevalent. They provide value to the system by delivering fast response, reserve and short-duration flexibility, helping to support secure operation as renewable penetration has increased.

As the generation mix changes, the system will need storage that can 'shift' more energy volumes over more extended periods of time. This is particularly relevant during extended periods of renewable surplus, network constraint or system stress. Longer duration storage can therefore help make better use of renewable generation, reduce curtailment and redispatch, and provide flexibility beyond the services delivered by the existing battery fleet.

For the initial LDES procurement, EirGrid recognises the system rationale for longer-duration storage with the tender evaluation criteria designed in a way that balances overall cost and benefit from incremental energy capacity/duration.

4.4.2 Capacity

The LDES scheme defines eligible units as having a minimum capacity of 20 MW (hybrid sites only- standalone sites must be a minimum of 75MW) and a maximum capacity of 100 MW.

The revenue floor bid limit, in absolute terms, is defined by the asset's maximum export capacity (MEC). As a result, an asset with a 100 MW MEC will have a higher absolute bid limit than an otherwise comparable asset with a 20 MW MEC. However, as the bid limit is expressed on a per-kW basis (EUR/kW-year), assets of the same duration will have the same bid limit on a per-kW level, regardless of their MEC. This per-kW value will, however, vary across durations, reflecting the different cost profiles associated with each storage duration.

4.4.3 Availability

The LCoS calculation incorporates an availability assumption. Based on our experience, BESS assets typically achieve availability levels above 95%. For the purposes of this analysis, a 95% availability assumption has been adopted, providing a reasonable allowance for operational downtime while remaining representative of expected asset performance.

We assume that scheme payments will not be adjusted to reflect the actual availability of individual technologies or projects. Consequently, assets with availability levels below the assumed threshold would not receive a corresponding adjustment to the payment value, resulting in a lower realised revenue than that assumed in the LCoS calculation.

4.4.4 Round-trip efficiency (RTE)

The LDES scheme sets a minimum round-trip efficiency of 75% for eligible assets. In practice, this means an asset must be able to discharge at least 75% of the energy used to charge it. Round-trip efficiency varies by technology. For the initial LDES scheme, the methodology focuses on Li-ion battery performance, which meets the minimum requirement. We have assumed a round-trip efficiency of 85% for this analysis, as this is typically the industry standard expected for Li-ion batteries.

4.4.5 Build time

Development and construction build times vary by storage technology. For utility-scale Li-ion battery systems, construction typically takes around one to three years. For this analysis, we use two years as the reference build time assumption.

4.4.6 Summary of technical specifications

Exhibit 4.10 contains a summary of the relevant technical specifications necessary.

Exhibit 4.10 – Summary of technical specifications for the LCoS calculation.

Specification	Unit	Value
Build time	years	2
Lifetime	years	15
Number of cycles	#	4,500–5,000
Optimal SoC range	%	15/20 – 100%
Availability	%	95%
Annual degradation	% per year	1.5%
Cycling degradation	% per 365 cycles	0.5%

Source: AFRY analysis based market intelligence .

4.5 Cycling

4.5.1 Degradation

Li-Ion batteries degrade due to both cycling and ageing. Operating within the recommended state-of-charge range can reduce degradation, with a level of around 60% state of health commonly treated as an end-of-life threshold based on AFRY's experience, and may require replacement of battery modules. The expected cycling pattern therefore affects the asset's degradation profile and its useful life.

The LCoS calculation includes a capex allowance for battery oversizing to help manage degradation from cycling and ageing. It also includes a fixed opex allowance for replacement of degraded components. These allowances are intended to support continued asset performance over the contract period.

4.5.2 Cycling assumptions for DE LCoS

For the DE LCoS comparison, we assume one full cycle per day for 4-hour batteries, 0.8 cycles per day for 6-hour batteries, 0.7 cycles per day for 8-hour batteries and 0.55 cycles per day for 12-hour batteries. These assumptions are used only for the delivered-energy comparison (shown for informational purposes only) and not for the EUR/kW-year revenue floor bid limit.



5 Proposed LCoS and revenue floor bid limit

The LCoS assessment reflects the availability payment structure of the revenue floor and is not based on a specific cycling assumption. The revenue floor requirements are set as a minimum annual requirement, and LDES service providers will be eligible for revenue floor payments based on their assessed annual revenues. Should they have a lower annual revenue than their revenue floor requirement, they will receive a top up payment. Should the asset capture revenues above the floor requirement the service provider gets to keep 70% of the upside but 30% is returned to consumers through an adjustment of the TUoS charge.

Minimum levels of availability will be a feature of the contracted service provision and non-compliance charges will be used where the service provider has traded outside the bounds of the trading envelope in any ex-ante market. In addition, the TSO proposes to introduce a non-trading activity scalar, whereby if the TSO assesses that service providers are not trading actively (for a minimum volume of trading periods per year) in a manner that can support the integration of renewable energy on the system then their revenue floor payments would scale downwards.

All other relevant market charges and incentives will apply as per the standard ex-ante market designs and will not be covered for LDES assets unless the trading envelope has explicitly prevented the asset from meeting its obligations. Assets are expected to operate within the Trading Envelope and respond to market price signals where that envelope does not restrict operation.

Consistent with the revenue floor design, the revenue floor bid limit is expressed in EUR/kW-year.

5.1 Bottom-up LCoS determination

Exhibit 5.1 presents the results of our LCoS analysis for 'typical' Li-Ion battery assets with different storage durations, each based on a reference grid connection of 20 MW.

Exhibit 5.1 – Bottom-up LCoS determination (EUR/kW-yr)

Year	4-hour			6-hour			8-hour			12-hour		
	Base case	High	Low	Base case	High	Low	Base case	High	Low	Base case	High	Low
2025	165	226	113	217	297	149	279	382	192	346	476	237
2026	158	217	109	208	284	143	267	366	183	327	450	224
2027	153	210	105	199	273	137	256	351	176	311	427	213
2028	146	200	100	190	260	131	244	335	168	296	407	203
2029	141	194	97	183	251	126	235	323	162	283	389	194
2030	137	188	94	177	242	121	227	312	156	271	372	186
2031	134	184	92	173	237	119	222	305	152	264	363	181

Source: AFRY analysis.

Comparing against values proposed in international markets for equivalent or similar mechanisms, our range for a 4-hr battery in 2025 (113 to 226 EUR/kW-yr) is comparable to that of the Italian MACSE (124 to 200 EUR/kW-yr). In the case of Western Australia, the reference cost of 296.6 EUR/kW-yr for a 6-hr battery is similar to the upper end of our range, with the High being at 297 EUR/kW-yr.

5.2 Implied LCoS based on auction/tender outcomes

The MACSE outcome highlights how competition can help deliver lower prices. The reserve premium was set at 37.0 EUR/kWh-year, sufficiently high to give developers confidence that projects facing real delivery, financing or supply-chain challenges could still participate. However, the auction was more than four times oversubscribed, and competitive pressure drove the weighted average clearing price down to 13.0 EUR/kWh-year, with zonal clearing prices ranging from 12.1 EUR/kWh-year in South and Calabria to 15.8 EUR/kWh-year in Sicily. This is equivalent to an **implied LCOS of 48 EUR/kW-yr to 63 EUR/kW-yr for a 4-hour battery**. This level is well below our bottom-up LCOS estimates.

This is an important consideration for the LDES revenue floor bid limit. The value should be high enough to avoid excluding credible projects or underestimating industry delivery challenges. However, should there be more limited competition, there is scope for adjusting the revenue floor bid limit to a level that is closer to what has been observed in other similar procurement processes to help protect consumers. The choice between a bottom-up LCOS estimate, one implied by outcomes from other similar procurement processes or a blend of these should also be informed by the expected competition, and be taken closer to the start of the procurement process.

5.3 DE LCoS results

We also present the DE LCoS for reference. This can be used to compare the cost of delivered energy across different storage durations on a like-for-like basis.

Exhibit 5.2 – DE LCoS values (EUR/MWh)

Year	4-hour			6-hour			8-hour			12-hour		
	Base case	High	Low	Base case	High	Low	Base case	High	Low	Base case	High	Low
2025	107	147	74	118	161	81	130	178	89	137	188	94
2026	103	141	71	113	154	77	124	170	85	129	177	88
2027	100	137	68	108	148	74	119	163	82	123	168	84
2028	95	130	65	103	141	71	113	155	78	117	161	80
2029	92	126	63	99	136	68	109	150	75	112	153	76
2030	89	122	61	96	131	66	105	145	72	107	147	73
2031	87	120	60	94	129	64	103	142	71	104	143	71

Source: AFRY analysis.

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