



The No-Regrets Build-Out: the transition assets you can own without winning a forecast argument

THE DALMORE INFRASTRUCTURE SERIES

This document is intended for professional investors only. This document is for information purposes only and does not constitute investment research, advice or a recommendation. All investments contain risk and may lose value. Past performance is not a reliable indicator of future returns.

Information and explanations from public or third-party sources used in this document have been deemed reliable by Dalmore Capital at the time of writing, however no representation is made by Dalmore Capital as to the reasonableness, completeness or accuracy of the same. Any opinions, estimates, or forecasts expressed are the current views of the author(s) at the time of publication and are subject to change without notice. Information is as at 21 October 2026 unless otherwise stated.

Disclosure of interests: Dalmore-managed vehicles hold interests in Cadent Gas, Anglian Water, Cory Riverside, a portfolio of EDF onshore wind assets, Scottish run-of-river hydro assets and an offshore transmission (OFTO) asset — positions spanning the gas and electricity systems, water, energy from waste and carbon capture discussed in this series; they are disclosed so that readers can weigh the analysis with full knowledge of the author's interests. Forward-looking statements are estimates only.

Dalmore Capital Limited is authorised and regulated by the Financial Conduct Authority (FRN:509930).

The energy transition is full of forecast arguments — about heat, hydrogen and how much power AI will really need — but a core set of assets is needed in every credible future, and it is large enough to build an allocation around. Alistair Ray, Chief Investment Officer of Dalmore Capital maps that no-regrets core — an electricity transmission programme Ofgem says may need over £70 billion of investment in 2026–31, a carbon-capture programme with up to £21.7 billion of committed funding over 25 years, a grid-scale battery fleet grown roughly seven-fold in five years — and the discipline that still earns the return: own the assets no scenario cancels, and let structure and entry price do the rest.

1. KEY POINTS

- The method is regret minimisation, not prediction: assets needed in every column of the scenario matrix — whatever happens to heat, AI demand or hydrogen — can be underwritten on entry price, structure and execution rather than on forecasts — project by project, because a needed sector can still hold surplus capacity and weak assets.
- The opportunity is committed work-in-progress at its core and a pipeline around it, not aspiration: £28.7 billion of approved upfront network investment across transmission and gas networks, alongside an electricity transmission programme that could exceed £70 billion under Ofgem's 2026–31 settlement, up to £21.7 billion of committed 25-year CCUS funding and Sizewell C on a Regulated Asset Base (RAB) — with the first cap-and-floor awards for long-duration storage and 83 GW of battery capacity with Gate 2 status still to be converted into funded projects.
- Deliberately contrarian: grid-scale wind and solar pass the scenario test best of all, yet the returns are mostly competed away — attractive only with development, repowering, storage co-location or repriced entry.
- Storage is a duration ladder, not one asset class: batteries' 2023–24 saturation is the discipline lesson, cap-and-floor long-duration storage is, in the author's view, today's best risk-adjusted entry in the flexibility stack, and the weeks-to-seasons rung still has no contracting model — though 2026's gas shock and a near-empty Rough have forced the question.
- Whole networks change hands rarely, and in sizes beyond the mid-market's reach; the mid-market opportunity is the capital that must get into the system around them — OFTOs, CATOs, IDNOs — and the Government's new Great British Grid, which will bid in the same tenders rather than nationalise anything, is a signal that more projects will be tendered, not fewer. In charging, the segment is the strategy.
- The credentials paradox protects the return: the assets that pay are the hardest to badge as green, and the crowding follows the badge, not the contribution — provided the sustainability case is evidenced, not asserted.

2. EXECUTIVE SUMMARY

The energy transition is full of arguments — about heat, about hydrogen, about how much power artificial intelligence will really need. The investability test is straightforward: transition assets must work economically, or be early on a credible path to doing so; otherwise they are policy speculation rather than sound infrastructure. This paper adds a second discipline that matters just as much for portfolio construction: **scenario robustness**. Some transition assets only pay if a particular forecast comes true. A smaller, more valuable set is required under every credible future — and that set is large enough to build an entire allocation around.

The method is regret minimisation, not prediction. For each asset class we ask how it fares across the genuinely open questions of the British transition: whether heat electrifies fully or follows the two-network path; whether AI-driven demand booms or disappoints; whether hydrogen scales or stalls. Assets needed in every column of that matrix —

electricity networks, storage and flexibility, fleet and en-route EV charging, industrial cluster infrastructure, the fuels build-out for aviation and shipping, and the supply chain that delivers all of it — can be underwritten on entry price, structure and execution, without betting the portfolio on any scenario. System need is not project demand, though: the matrix shows that an asset class stays relevant in every future, not that every location, size or commissioning date does, and a needed sector can still hold surplus capacity and weak assets — which is why the entry-price discipline matters as much as the selection.

The opportunity is unusually concrete. Ofgem's December 2025 settlement approved £28.7 billion of upfront network investment for 2026–31 within a pipeline of roughly £90 billion, with electricity transmission alone potentially exceeding £70 billion and distribution to follow; up to £21.7 billion of 25-year carbon capture funding has been committed; Sizewell C has taken the RAB model into nuclear; long-duration storage has its first cap-and-floor awards in prospect; grid-scale batteries have grown seven-fold in five years, with some 83 gigawatts holding Gate 2 status.¹ These are not policy aspirations, but nor are they all the same thing: the approved allowances and the carbon-capture funding are committed money; the wider pipeline, the storage awards and the connection agreements are prospects that still have to become funded projects. The committed core is work-in-progress, and much of it sits in segments that mid-market capital can access directly — segments the Government chose to widen rather than close when it announced Great British Grid in September 2026 as a competitor in tendered transmission, not an owner of the existing networks.

Discipline still earns the return. No-regrets does not mean no-risk: batteries carry merchant revenue cyclicality, charging returns divide sharply by segment, and the supply chain rewards those who distinguish infrastructure from manufacturing. A final discipline concerns evidence rather than economics: many of the assets this paper favours are the hardest to badge as green. Section 10 argues that this very obscurity is part of what protects their returns from crowding — provided the sustainability case is evidenced rather than asserted. Section by section, this paper sets out where the durable structures sit and what would change each case. One sector is deliberately absent: heat, where the scenarios genuinely diverge; the companion paper Heating Britain treats that question in full. Water and climate resilience, a major British investment story in its own right, is treated separately in Water Beyond Thames.

3. INVESTING WITHOUT A CRYSTAL BALL

Infrastructure investors are routinely asked to take a view on questions that will not resolve for a decade: the pace of heat electrification, the realism of AI demand projections, hydrogen's eventual role. The honest answer is that nobody knows — the range of credible expert opinion on each is wide. Portfolio construction should not pretend otherwise.

The response is not paralysis but selection. Rank the transition's asset classes by how their demand holds up across the scenarios, and a striking pattern emerges: a substantial core is needed in every future, differing only in scale or timing. A system that electrifies heat fully needs dramatically more network and peak capacity; a two-network system still needs far more than exists today. An AI boom accelerates the grid build-out; an AI disappointment still leaves a reformed connection queue of 283 GW of generation and storage and almost 100 GW of new transmission-connected demand — 87 GW of it sought for 2030–35, with data centres prominent among the applicants.² Hydrogen's fate moves the shape of industrial clusters, not their existence. Assets in this core can be underwritten on entry price, structure and execution — the things an investor can actually control — rather than on forecasts. The matrix below sets it out.

The no-regrets test: needed in every column

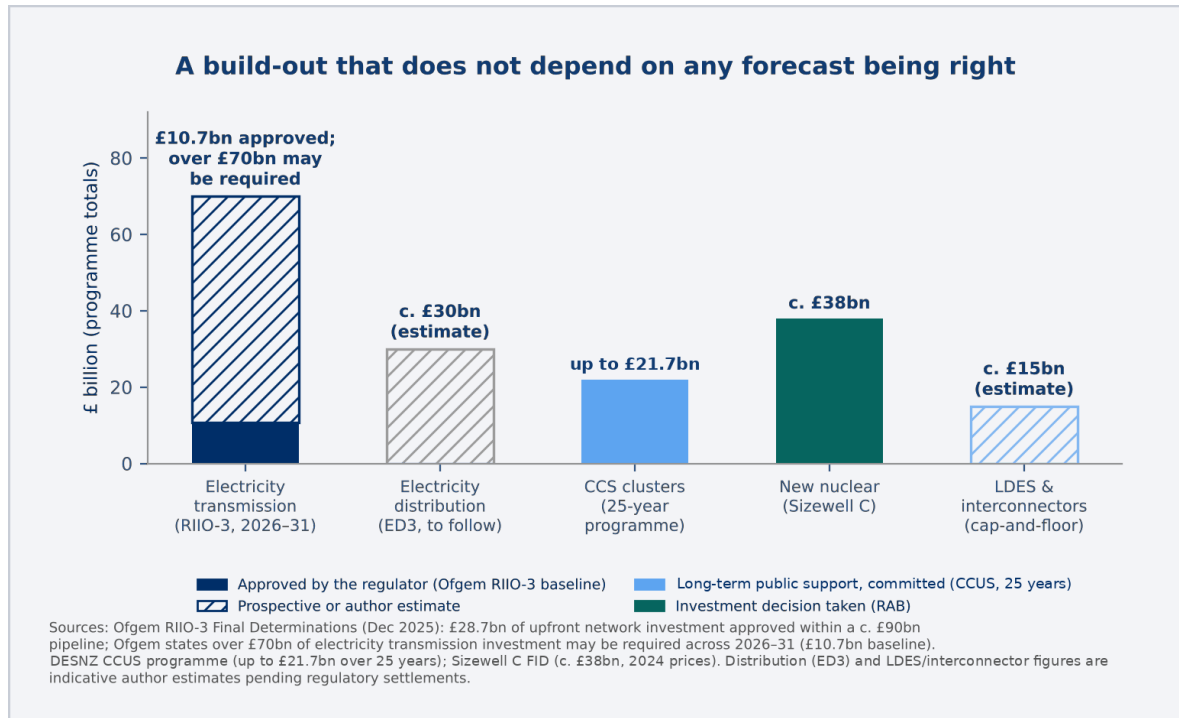
	Heat		AI demand		Hydrogen	
	all-electric	two-network	booms	disappoints	scales	stalls
Electricity networks	needed	needed	needed	needed	needed	needed
Batteries & LDES	needed	needed	needed	resized	needed	needed
Interconnectors	needed	needed	needed	resized	needed	needed
EV charging (fleet/en-route)	needed	needed	needed	needed	needed	needed
CCS cluster infrastructure	resized	needed	needed	resized	needed	resized
SAF & port fuel infrastructure	needed	needed	needed	needed	resized	needed
New nuclear (RAB)	needed	resized	needed	resized	needed	needed
Grid supply chain	needed	needed	needed	resized	needed	needed

Source: Dalmore. 'Resized' = required in that scenario at smaller scale or later date, not eliminated. Illustrative summary of the scenario analysis in this paper.

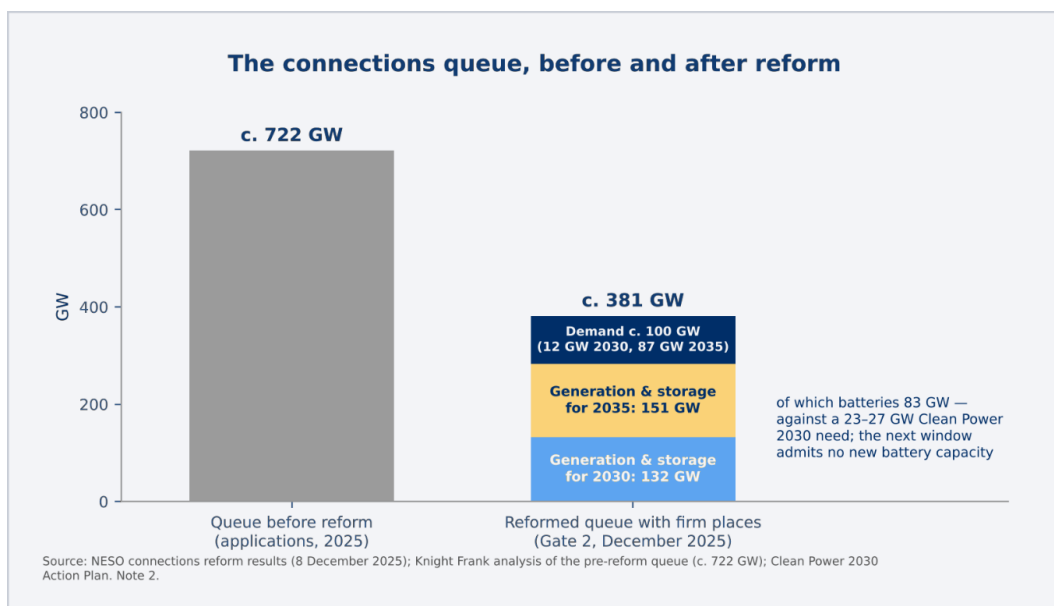
The matrix also identifies what this paper is *not* about. Assets whose case rests on a single contested scenario — hydrogen for home heating is the canonical example — belong in the 'policy speculation' category until the scenario resolves. And one great sector resists the no-regrets logic entirely: domestic heat, where the all-electric and two-network futures imply genuinely different asset bases. The companion paper Heating Britain develops that argument.

4. NETWORKS: THE BACKBONE TRADE

Every scenario in the matrix runs through the same wires. Ofgem's RIIO-3 settlement, in force since April 2026, approved £28.7 billion of upfront network investment for 2026–31 within a pipeline of roughly £90 billion — electricity transmission alone could exceed £70 billion over the period, a programme of a scale Ofgem has said it has probably not seen since the National Grid was formed in the 1960s — remunerated under the regulated asset base model that has financed British infrastructure for three decades.¹ Distribution reinforcement follows behind it, and the connections queue — more than 700 gigawatts before reform, cut to 283 GW of generation and storage plus almost 100 GW of new demand with firm places in the reformed queue — is evidence of demand for grid access that no plausible downside scenario exhausts.² The cost of building generation faster than wires is already on the bill: wind-related constraint payments reached about £1.5 billion in 2025 and had passed that level again by October 2026, and every pound of them is an argument for the programme this section describes.²



The important structural point is that the networks themselves are, for practical purposes, closed to new mid-market owners. Britain's transmission and distribution companies sit either in listed vehicles or with long-term strategic holders — sovereign funds, pension consortia, utilities — who acquired them over two decades and rarely sell into the most capital-hungry period of the assets' lives — and when one does, as with ENGIE's purchase of UK Power Networks, agreed in February 2026 at a £10.5 billion equity value and completed in May, the transaction is large, infrequent and beyond the practical scope of mid-market funds. Direct acquisition of a network is therefore rarely the opportunity. The opportunity is the capital that has to get *into* the system around those owners: a programme on this scale strains even incumbent balance sheets, and the regulatory architecture is deliberately multiplying the mechanisms by which outside capital participates.



Those mechanisms are precisely the mid-market entry points, and they are less crowded than the assets they orbit: **offshore transmission assets (OFTOs)**, auctioned with availability-based regulated revenues over 20–25-year terms as

each offshore wind connection is built and sold down; **competitively appointed transmission (CATOs)**, extending that auction logic onshore — belatedly: the first candidate, a new double circuit between north-west England and south-west Scotland, was withdrawn in 2025 when Ofgem found it did not yet qualify, but the draft licence is now out, NESO is to nominate projects in late 2026 and the first tender is expected in 2027; **independent distribution networks (IDNOs) and last-mile connection businesses**, which build and own the final network segment for new developments — growing with every housing estate, data centre and depot connection regardless of which transition scenario unfolds; and the further structures the build-out will force into existence, from single-project financings of major links to minority stakes sold to fund capex.³ These are quintessential no-regrets positions: regulated or contracted revenues, demand underwritten by physics rather than forecasts — and a seller (the system itself) that must keep issuing them for two decades.

The newest entrant is the state. In September 2026 the Government announced Great British Grid: a publicly owned network company within Great British Energy that will "bring together public and private investment" and compete for transmission projects alongside the incumbents, with start-up costs met from GBE's existing budget and its long-term funding left to a future spending review.³ Existing network operators keep their roles, as do Ofgem and NESO: competition, not nationalisation, as HSF Kramer reads it.³ For the CATO regime the announcement is, on balance, good news. A government that has created a state bidder has every incentive to accelerate the tendering that lets it bid — and said so, promising to "accelerate the competitive tendering of transmission projects" so that "a wider range of organisations, including Great British Grid" can deliver new network infrastructure — while Ofgem's draft CATO licence, consulted on until 16 October, sets out the draft terms private capital has been waiting for: a 35-year availability-based revenue stream, a refinancing mechanism passing gains and losses to consumers, a normal 98% availability target and a first tender expected in 2027 once NESO nominates projects in late 2026. Alongside it come an independent transmission owner licence and a right for developers and large users to build their own connections — the Irish model, credited there with cutting connection times by up to eleven months — which widen the last-mile entry point this paper already favours; and because most developers want to build a connection without keeping it, a state company willing to take the finished asset as co-investor or owner would be a new counterparty for that segment as much as a new rival. Two caveats are honest ones. Nobody has yet said what "accelerate" means against Ofgem's 2027 timetable, and the first early-competition assets are not due in service until the mid-to-late 2030s. And competitive neutrality is unresolved: a bidder with the state's cost of capital could crowd out the private capital the regime exists to attract, so the tender rules will have to say how a public bidder is treated — just as they already ring-fence National Grid when it bids. Our reading is that the politics now run towards more tendered projects rather than fewer — the thesis of this section — and that the discipline for a private bidder is unchanged: bid where the asset's risk and its 35-year revenue are properly priced, and not where a state balance sheet has decided to win. One listed investor's view deserves the last word, because it is this paper's own argument in Section 9: the binding constraint on the grid build-out is not capital but the skilled workforce to deliver it.³



5. GRID-SCALE RENEWABLES: ROBUST DEMAND, COMPETED RETURNS

“The no-regrets discipline applies to what the system needs, not to any price paid for it.”

— Alistair Ray, Chief Investment Officer, Dalmore Capital

An honest no-regrets paper must deal with the apparent anomaly at the heart of transition investing: grid-scale wind and solar pass the scenario test more comfortably than anything else in this paper — every future needs more of them — and yet we generally find them unattractive. The two facts are connected. Scenario-robustness this obvious is fully priced. An operational, CfD-backed wind or solar farm is, in investment terms, close to a commodity: homogeneous cash flows, revenues set by auction, no meaningful operational differentiation, and a valuation determined almost entirely by the global cost of capital. It is precisely the asset that the world's largest specialist funds and core vehicles are built to own, and they compete for it accordingly. In heavily brokered processes for de-risked assets, the winner is usually the bidder prepared to accept the lowest return — and sometimes one who has mispriced the risk. Passing the demand test is necessary; it is not sufficient. *The no-regrets discipline applies to what the system needs, not to any price paid for it.*

The exceptions are where genuine scarcity re-enters, and they matter because they are the difference between owning the commodity and being paid for skill. **Development and construction exposure** — sites, planning, grid connections, PPA structuring — earns a premium precisely because those capabilities are scarce while operating assets are not; develop-to-core strategies capture the value the auction gives away. **Repowering and life extension** of the ageing early fleet is a growing, under-competed niche with development-like economics on brownfield risk. **Co-location with storage** converts a price-taking generator into a flexibility asset — connecting this section to the next. And **repriced secondary situations** — including the listed renewables trusts trading at persistent discounts to asset value — periodically offer the commodity at a non-commodity price. Each exception shares a feature: the return comes from something other than simply owning megawatts.

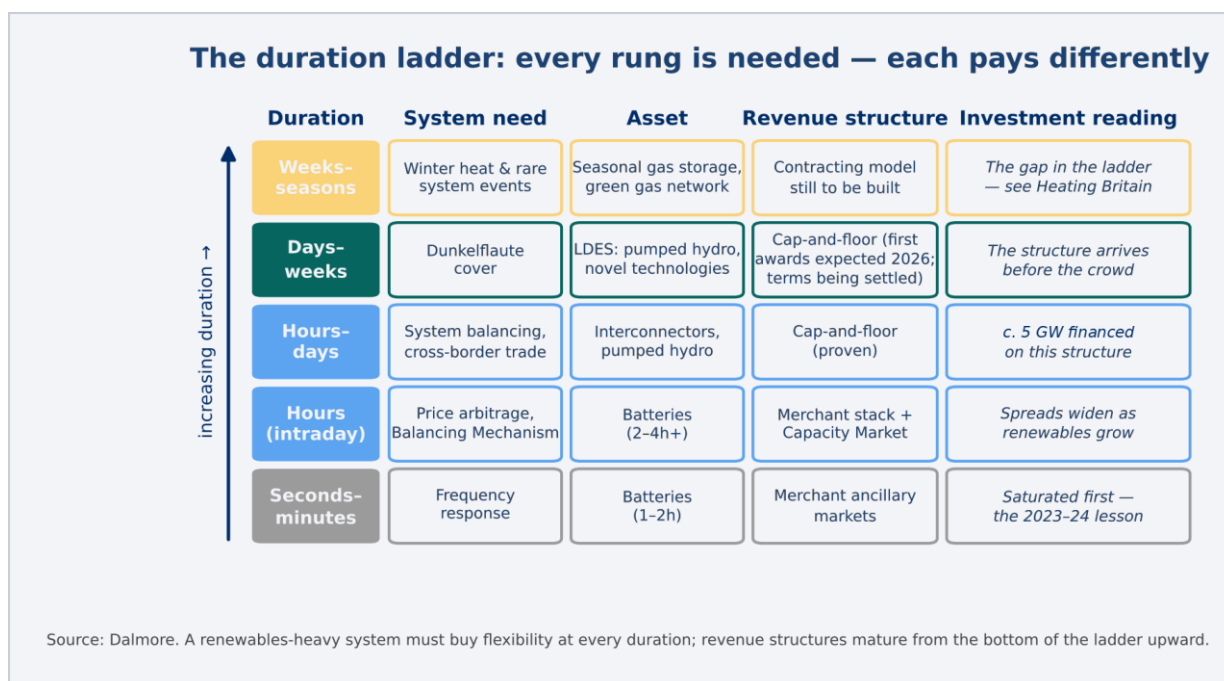
Our conclusion is deliberately contrarian for a transition series: the most celebrated transition asset class is, for a mid-market value investor, mostly the least interesting — not because the assets are poor but because the returns are competed away. The rest of this paper is, in effect, a map of where they went: into the networks that connect the renewables, the flexibility that firms them, the segments and structures where capital remains scarce. We hold renewable generation ourselves and expect to again — but on our terms: with development elements, repowering angles, storage co-location or repriced entry, never as a plain bid for operating megawatts in a crowded auction.

The same paradox has a sustainable finance reading, and it matters for how mandates are written. Investors increasingly want two things at once: credible sustainability and competitive returns. 'Dark green' assets such as operational wind and solar are the easiest to badge — their contribution is visible, measurable in megawatt-hours and instantly legible in a sustainability report — and that very legibility draws in the capital that competes their returns down. Transition assets — an energy-from-waste plant adding carbon capture, a gas network progressively greening its gas — sit outside that crowding. Their contribution is harder to explain and harder to badge, but it can be just as substantial, and the returns genuinely attractive — partly for that very reason. A mandate that selects on visible sustainability alone will therefore screen out precisely the assets this paper argues are most attractively priced. Section 10 sets out what that implies for evidencing the sustainability case.

6. STORAGE AND FLEXIBILITY: THE DURATION LADDER

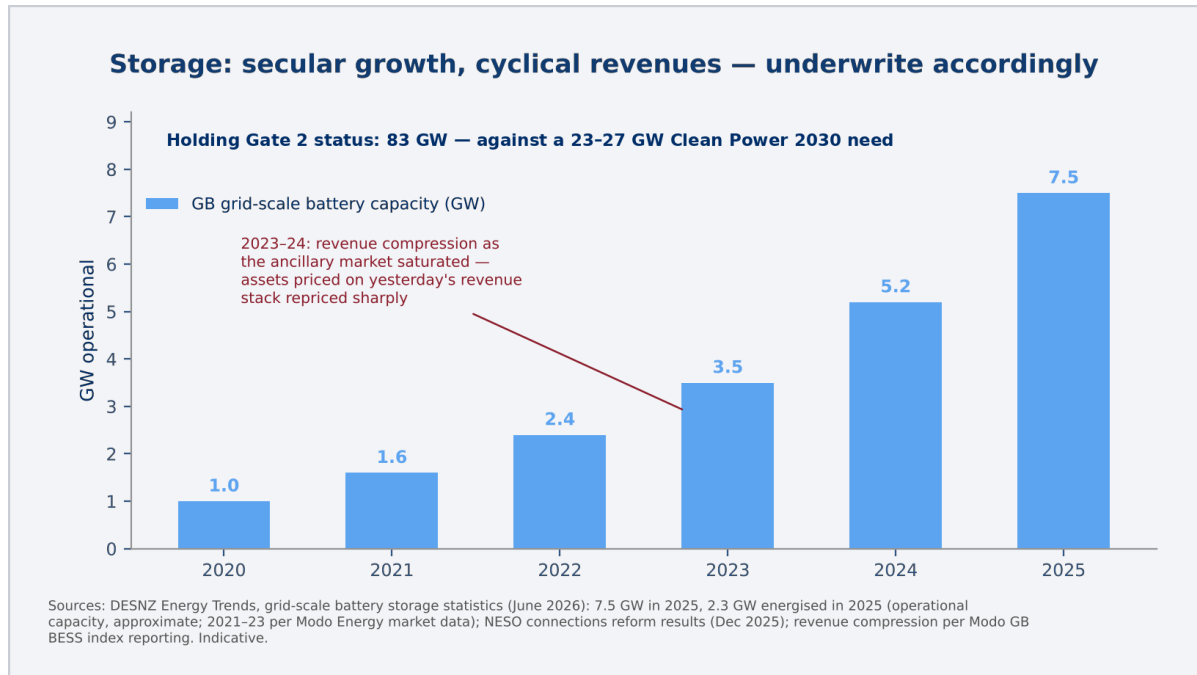
If networks are the transition's backbone, storage is its balance sheet — and it deserves more space than transition portfolios typically give it, because it is not one asset class but a ladder of them.

A renewables-heavy system must buy flexibility at every duration: sub-second frequency response, intraday arbitrage, multi-day balancing, the two-week windless cold spell, and the seasonal swing of winter heat. Each rung serves a different system need, is served by different assets, and — critically for investors — pays through a different revenue structure at a different stage of maturity. The rungs are complements, not competitors: cheap batteries do not solve Dunkelflaute, and seasonal storage is wasted on intraday spreads.



The demand side of every rung strengthens mechanically as renewables grow. More wind and solar means more zero-marginal-cost hours and more scarcity hours — wider spreads, more balancing actions, greater locational divergence. Flexibility is the one part of the system whose revenue *opportunity* is created by the build-out of everything else, which is what makes it robust across every column of our scenario matrix: even in the futures with less heat electrification or less AI demand, the renewables already contracted guarantee the volatility that flexibility monetises.

Batteries occupy the ladder's bottom rungs and have already taught the sector its first discipline lesson. Capacity has grown from roughly a gigawatt to around seven and a half in five years, with some 83 GW holding Gate 2 status against a 23–27 GW Clean Power 2030 need⁴ — but in 2023–24 the frequency-response market saturated and revenues compressed sharply, repricing assets underwritten on yesterday's revenue stack. The lesson is not to avoid the sector; it is that *secular demand growth does not immunise merchant revenues against local saturation*. We would underwrite batteries on conservative wholesale-and-balancing stacks with Capacity Market agreements as the contracted floor, treat ancillary revenues as upside, favour longer durations as spreads widen, and prize sites — including co-location with generation — whose grid position provides durable locational value.



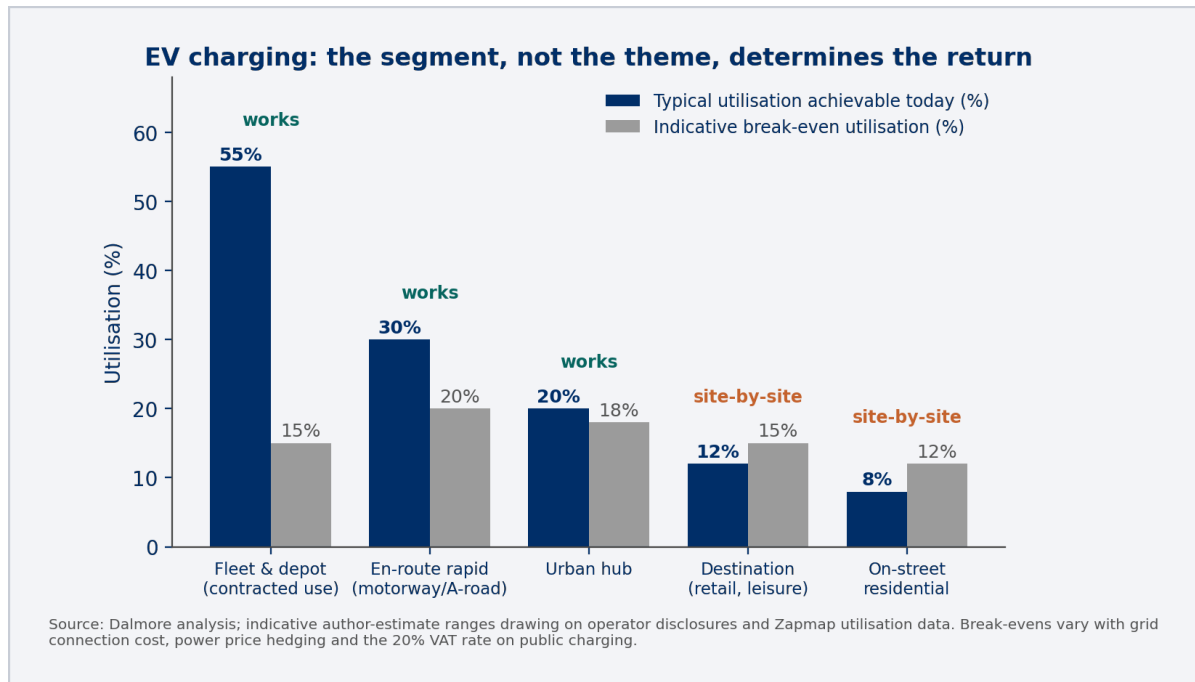
Up the ladder, the revenue structures improve just as the competition thins. **Interconnectors** proved the model: around 5 GW of GB interconnection was financed under cap-and-floor — floor for the lenders, cap for consumers, merchant incentive in between — and every scenario values the ability to trade power with neighbouring systems.⁵ **Long-duration storage** now inherits that proven architecture: in June 2026 Ofgem published minded-to awards from the first cap-and-floor window — sixteen projects totalling 7.6 GW and 137 GWh at eight to 32 hours' duration, led by three pumped-hydro schemes in Scotland alongside long-duration batteries, a compressed-air store and a flow battery — with final awards due in the autumn and a decision on a second window to follow.⁵ The regime's terms are still being settled, and the test of them is simple: the floor has to sit where the pumped-hydro schemes can raise construction finance against it, or the awards will not become assets. These are price-certainty structures of the kind governments should extend. Seventy-three projects assessed for sixteen minded-to awards says competition for the regime itself is real; what remains thin is capital for the construction phase of the pumped-hydro tranche, and the secondary market in awarded projects, which does not yet exist. That is where we would look. This is, in our view, the single most attractive risk-adjusted entry point in the flexibility stack today: multi-decade assets, physical scarcity, regulated downside protection, and a market that has not yet learned to price them.

The top rung is the revealing one. **Weeks-to-seasons storage** — the duration that covers winter heat and the rarest system events — has no contracting model at all yet, despite being the duration on which system security ultimately rests. Batteries cannot reach it economically; the assets that can are seasonal gas storage and the gas network itself, running on progressively greener gas. That gap in the ladder is not an accident of markets but of policy — a missing structure, exactly where returns should eventually migrate — and it is where the flexibility question joins the heat question. Heating Britain takes it up directly.

Events in 2026 made the gap visible. The closure of the Strait of Hormuz in March pushed British wholesale gas prices to more than double their level of a year earlier by late October; by September the operator of Rough, the country's largest gas store, described it as practically empty and warned it would close by spring 2027 without a support framework; and the Government's interim response on gas security accepted that long-term revenue support for storage may be required, recording cap-and-floor as the model operators most commonly favoured and a strategic reserve among the options raised.⁵ The missing structure, in other words, is being designed — which is what this paper would have predicted, and what makes the top rung worth watching rather than writing off.

7. ELECTRIC VEHICLE CHARGING: THE SEGMENT IS THE STRATEGY

The EV fleet transition is the consumer success story of the British transition, and it is robust across every scenario in our matrix — the vehicles are being bought in all of them, more than one in four new cars in 2026. The infrastructure behind it is where discipline pays, because the economics divide sharply by segment.⁶



Fleet and depot charging — buses, logistics, commercial vehicles — offers contracted utilisation from day one: the demand is scheduled, the counterparty is corporate, and the asset is closer to a utility than to retail. We regard it as the segment where charging is already infrastructure. **En-route rapid charging** on strategic roads clears its break-even at achievable utilisation and rising EV penetration mechanically lifts it further. **Destination and on-street charging** remain site-by-site propositions where operators dependent on assumed future utilisation have absorbed painful losses. The sector's early distress is, for disciplined capital, the opportunity: portfolios assembled in the boom are repricing, and consolidation at sensible entry multiples — anchored on the contracted and en-route segments, with destination assets as options rather than premises — is exactly the pattern by which young infrastructure classes mature. The comparison sometimes drawn with fibre is right about the build phase and wrong about the asset. Both sectors ran a lightly supervised land grab in which capital was spent ahead of demand, and in both the lost money belongs to the builders rather than to the second owner — which is why the sort by segment matters more than the sector label. Two differences are worth knowing. Charging platforms have been financed largely with equity, so their losses have arrived as down-rounds and trade sales rather than the lender-forced restructurings that repriced fibre within a few years — slower and shallower, with fewer forced sellers, which makes the entry point later and less generous than fibre's. And the strongest segments carry barriers fibre never had: a depot contract, a strategic-road concession, a grid connection that cannot be duplicated across the street. The VAT asymmetry between public charging and home electricity, and grid connection reform, are the policy levers to watch: both would move break-evens in the investor's favour.⁶

8. INDUSTRIAL CLUSTERS: CONTRACTED DECARBONISATION

Industrial decarbonisation looks daunting at economy scale but tractable where it is actually happening: in clusters, under contract. The Government has made available up to £21.7 billion over 25 years to the first carbon capture

clusters — HyNet in the North West and the East Coast Cluster — with revenue models that are price-certainty structures throughout: a regulated asset base for the transport and storage networks, CfD-style contracts for industrial capture, dispatchable power agreements for gas-CCS generation.⁷ This is the offshore wind playbook applied to industrial emissions: strategic support, competitively evolving, designed to hand over to the carbon price as the ETS tightens and the carbon border adjustment arrives from 2027.⁸

The no-regrets reading requires precision. The *cluster infrastructure* — pipes, stores, shared utilities — is robust: in every scenario Britain retains energy-intensive industry, that industry decarbonises under a rising carbon price, and clustered abatement beats dispersed abatement on cost. What varies by scenario is the mix running through it: more hydrogen production if hydrogen scales, more direct capture if it does not. Investors positioned in the shared infrastructure hold the tollbooth over that uncertainty rather than a bet on its resolution. Industrial hydrogen *within* clusters — ammonia, refining, high-grade heat — passes the test on the same logic; hydrogen ventures whose demand case requires households or road transport do not, and the distinction is the whole game.

9. AVIATION, SHIPPING AND THE FUELS BUILD-OUT

Aviation and shipping cannot electrify at scale on any relevant horizon, which makes their decarbonisation a fuels-manufacturing and logistics problem — and therefore an infrastructure opportunity. The UK's sustainable aviation fuel mandate creates obligated demand rising from 2% of jet fuel to 10% by 2030 and 22% by 2040, and the revenue-certainty mechanism legislated in March 2026 will give SAF plants a strike price, awarded competitively — the first allocation round opens in 2027 and contracts are expected from late 2028: a CfD for fuel, converting a policy target into a bankable revenue line.⁹ Shipping moved further than any observer expected, then stalled: the International Maritime Organization's framework — a global fuel standard with emissions pricing, the first genuinely worldwide carbon price on any sector — was approved in April 2025, had its adoption adjourned in October 2025 under American and Saudi pressure, and returns to the vote in December 2026.¹⁰ Adopted, it gives green fuel production, port electrification and bunkering infrastructure a revenue standard that does not depend on any single government's resolve; delayed again, it leaves the regional carbon regimes to carry the structure forward more slowly.

Both sectors sit in the growth column rather than the core: the structures are new, the technologies contested, and first-of-a-kind plants carry construction risk that must be priced. But the demand is obligated, the direction is contracted, and the physical assets — plants, storage, port infrastructure — will be scarce when the mandates bind. Early-mover infrastructure here follows the pattern this series keeps finding: the structure arrives first, generalist capital arrives later, and the interval belongs to investors who read the contracts early.

10. NEW NUCLEAR: THE RAB MODEL'S BIGGEST TEST

Nuclear divides opinion; the financing structure should not. Sizewell C reached its final investment decision financed under a regulated asset base — the first time Britain has applied its network-financing architecture to generation at scale — precisely because the alternative, loading construction risk onto a contracted power price, produced Hinkley Point C's cost of capital and Hinkley Point C's strike price.¹¹ The RAB is price certainty applied to the hardest case, and its performance at Sizewell will determine how cheaply Britain can finance firm low-carbon capacity for a generation. Small modular reactors, with Rolls-Royce SMR contracted by Great British Energy — Nuclear in April 2026 to deliver three units at Wylfa, the first site, are the classic strategic early asset under this framework: worth supporting through a disciplined, falling-cost programme, investable in stages as delivery de-risks.¹¹ In scenario terms, nuclear is needed most where heat electrifies fully and AI demand booms; in the two-network future its role is smaller but not zero. We class it as core-adjacent: robust in direction, scenario-sensitive in scale.

11. THE PICKS AND SHOVELS

Every asset in this paper depends on a supply chain that is now the transition's binding constraint. High-voltage cable and converter manufacturing capacity is being reserved years ahead; large transformer lead times have stretched to as much as four years; specialist installation vessels, switchgear and skilled labour are all scarce.¹² Scarcity of this kind is usually where returns migrate, and some of it is investable in infrastructure form: ports configured for offshore wind assembly, cable-laying and installation vessels under long charters, training and grid-services platforms with framework contracts.

“Done carefully, the picks-and-shovels layer is the purest no-regrets exposure of all: it is paid by whichever version of the transition gets built, because all of them must be physically delivered by the same constrained fleet of ships, factories and engineers.”

— Alistair Ray, Chief Investment Officer, Dalmore Capital

The test from *The Investable Transition* applies with full force, because the supply chain is where infrastructure shades into manufacturing. A cable factory is a cyclical industrial business however green its order book; a port with a 15-year offshore wind assembly lease is infrastructure. The discipline is to own the scarce, contracted, hard-to-replicate layer — and to resist paying infrastructure multiples for manufacturing risk. Done carefully, the picks-and-shovels layer is the purest no-regrets exposure of all: it is paid by whichever version of the transition gets built, because all of them must be physically delivered by the same constrained fleet of ships, factories and engineers.

12. THE CREDENTIALS PARADOX: THE ASSETS THAT PAY ARE THE HARDEST TO BADGE AS GREEN

A cluster pipeline does not photograph well in a sustainability report; nor does an OFTO, a transformer port or a cap-and-floor pumped hydro scheme — yet nothing in the transition decarbonises without them. In sustainable finance terms these are enabling assets: their own emissions profile says little about their contribution, which is delivered through what they allow the rest of the system to do.¹³ That obscurity is part of what protects the return — the crowding described in Section 3 follows the badge, not the contribution — but it shifts the burden of proof onto the manager. The sustainability case for a transition asset must be evidenced, not assumed: through transition plans aligned to the Transition Plan Taskforce framework, taxonomy treatment of enabling activities, and reporting that connects the asset to the system outcome it serves.

The same test doubles as risk management. An asset needed in every credible pathway is, by definition, the least likely to be stranded — the scenario matrix of Section 1 is a transition-risk screen as much as an origination tool. Institutional investors already run climate scenario analysis for their statutory disclosures; the no-regrets discipline applies that thinking before an asset is bought, not merely when reporting on it afterwards.

13. WHAT THIS MEANS FOR INVESTORS — AND WHAT FOLLOWS

“Networks, storage, flexibility, contracted charging, cluster infrastructure, the fuels build-out and the supply chain are needed in every credible future; what they pay is decided by entry price, location and revenue structure.”

— Alistair Ray, Chief Investment Officer, Dalmore Capital

The no-regrets core answers the objection most often raised against transition investing — ‘but what if the forecasts are wrong?’ — by declining the bet. Networks, storage, flexibility, contracted charging, cluster infrastructure, the fuels build-out and the supply chain are needed in every credible future; what they pay is decided by entry price, location and revenue structure — the matrix establishes the need, not the return. The craft lies in structure and entry: regulated and contracted revenues over merchant hope, segments over themes, repriced consolidation over boom-time primary, and the mid-market corners — OFTOs, IDNOs, depots, the construction and secondary phases of the first cap-and-floor awards, the first CATO tenders — where competition remains thin or is only now forming. And investors need not accept that sustainability comes at the cost of return: the two can be had together — but only from managers able to evidence the sustainability case through recognised frameworks rather than merely assert it.

What this paper deliberately leaves open is the transition's genuinely contested question: how Britain heats its homes. There, the scenarios diverge so far that no-regrets logic runs out, a real argument must be had, and the answer determines the fate of two national networks. The companion paper Heating Britain develops that argument — and reaches a conclusion the reader of this one will find familiar in method: the pathway that works economically is the one that will be built. Water and climate resilience, which sit outside the transition proper but inside every serious infrastructure allocation, are the subject of the series' closing paper, Water Beyond Thames.

14. ABOUT DALMORE CAPITAL AND ROYAL LONDON ASSET MANAGEMENT

Dalmore Capital is part of Royal London Asset Management, the asset management arm of Royal London. Dalmore Capital is a UK infrastructure investment manager overseeing more than £5.7 billion of capital on behalf of institutional investors. The firm currently manages a diversified portfolio of 128 infrastructure assets accumulated since its formation in 2009, across Core, Core+ and PPP social infrastructure assets.

15. NOTES AND REFERENCES

1. Ofgem, RIIO-3 Final Determinations overview (4 December 2025; 2023/24 prices): £28.7bn of upfront investment approved across electricity transmission (baseline £10.7bn), gas distribution (£14.8bn) and gas transmission (£3.2bn) for 2026–31 (Ofgem's press release and investor call give £28.1bn; the overview gives £28.7bn, which we use), within a wider pipeline of c. £90bn; Ofgem states that over £70bn of electricity transmission investment may be required across the period, released through in-period mechanisms as projects are approved. On the RIIO-3 investor call (4 December 2025), Ofgem's Director of Network Price Controls described the electricity transmission programme as “a £70 billion plus programme” and as one Ofgem had “probably” not seen the like of since the National Grid was formed in the 1960s. The price control took effect on 1 April 2026; SSEN Transmission accepted its determination in March 2026. Electricity distribution (RIIO-ED3, from April 2028) follows; the c. £30bn figure shown is an indicative author estimate pending that price control.

2. NESO connections reform (results published 8 December 2025): a queue of over 700 GW before reform (NESO; c. 722 GW per Knight Frank's analysis) — about four times the capacity required (Knight Frank) — reduced to c. 283 GW of generation and storage with Gate 2 status (132 GW for 2030, 151 GW for 2035), plus almost 100 GW of transmission-connected demand (11.8 GW for 2030, 86.7 GW for 2035), with Ofgem's chief executive, in NESO's release, citing AI and data centres among the demand drivers. Batteries hold 83.2 GW of Gate 2 capacity against the 23–27 GW Clean Power 2030 range, and NESO's December 2025 position was that the next application window would have no capacity for new batteries, with its timing yet to be confirmed. Wind-related constraint costs: c. £1.47bn in 2025 and over £1.5bn by 5 October 2026 (Wasted Wind tracker, Elexon data); total constraint costs are higher, c. £1.8bn for 2025 (EDF).
3. OFTOs: offshore transmission assets auctioned under the Ofgem tender regime with 20–25 year availability-based revenues; Ofgem's consultation on an OFTO-build model closed in July 2026 with a decision pending. IDNOs: independent distribution network operators building last-mile networks for new connections. Whole-network transactions: ENGIE agreed in February 2026 to acquire 100% of UK Power Networks at an equity value of £10.5bn (completed in May 2026) — infrequent, large and outside the mid-market's practical scope. CATO/onshore competition: provided for under the Energy Act 2023; Ofgem selected a sub-component of WCN2 (a new double circuit between north-west England and south-west Scotland) as the first early-competition project on 4 April 2025 but determined on 30 July 2025 that it did not meet the qualifying requirements, citing that it could not confirm the network needs case given uncertainty over the impact of connections reform, the Strategic Spatial Energy Plan and Clean Power 2030; no project has since been designated. NESO's expression-of-interest exercise (March–April 2026) was a market sounding to identify candidates, with a first recommendation to Ofgem expected later in 2026. Ofgem, draft CATO licence and guidance (consultation 19 August – 16 October 2026): a 35-year tender revenue stream from commissioning, a post-preliminary-works cost adjustment subject to a 40% cap (Ofgem expects a higher cap for the first tender), an availability incentive normally targeting 98%, a refinancing mechanism with full pass-through of gains and losses to consumers, and a year-30 review (decommissioning, extension or retender); first tender anticipated in 2027. Great British Grid: announced 29–30 September 2026 (Prime Minister's conference speech; DESNZ statement) as a publicly owned network company and, in the Prime Minister's words, "a new branch" of Great British Energy, to "bring together public and private investment to support the delivery of critical network infrastructure" and to compete in the competitive tendering of transmission projects, which the Government undertook to accelerate; existing network operators' roles unchanged (DESNZ), as are those of Ofgem and NESO; start-up costs from GBE's budget, long-term budget at a future spending review (the Guardian, as cited by HSF Kramer, reports access to a c. £4bn pot within GBE); HSF Kramer considers primary legislation unnecessary under the Great British Energy Act 2025, though GB Grid would need a transmission licence. Accompanying connections reforms: an independent transmission owner licence and expanded self-build rights for developers and businesses, with Ofgem consultations in autumn 2026 (Irish precedent: connection times cut by up to eleven months). Competitive-neutrality questions under the Subsidy Control Act 2022 were raised immediately by advisers (HSF Kramer, Great British Grid: competition not nationalisation, 30 September 2026), who also note that incumbent National Grid may bid in CATO tenders subject to ring-fencing (Ofgem, 2024), that CATO projects must be new, separable, needed with reasonable certainty and likely to benefit consumers, that early-competition assets are targeted for commissioning in the mid-to-late 2030s, and that "it is not clear how GB Grid will accelerate this process". TRIG's Minesh Shah (Trustnet, 13 October 2026): "it isn't a lack of capital holding grid investment back"; "what is scarce is the skilled workforce to design, build and commission new grid capacity". The National Audit Office warned in September 2026 that delivering all the grid upgrades by 2030 "will be very challenging".
4. DESNZ, Energy Trends special article, Grid-scale battery storage statistics (30 June 2026): UK grid-scale battery capacity reached 7.5 GW in 2025, with 2.3 GW energised in 2025 alone, from c. 1 GW in 2020. Clean Power 2030 Action Plan: 23–27 GW of batteries by 2030. Revenue compression in 2023–24 reflected saturation of frequency-response markets (Modo Energy, GB battery energy storage markets: 2024 year in review); revenues have since partially recovered on wholesale trading and Balancing Mechanism access. Figures approximate; the operational and pipeline datasets use different boundaries and should not be added together.
5. Ofgem, long-duration electricity storage cap-and-floor, Window 1 minded-to decisions (26 June 2026): 16 of the 73 projects assessed (77 eligible; four withdrew), 7,645 MW and c. 137 GWh (derived from Ofgem's Table 1;

Ofgem states MW only) at eight to 32 hours' duration — three pumped-storage hydro (Coire Glas, Earba and Loch Kemp, all in the north of Scotland), eleven lithium-ion, one compressed-air and one vanadium flow — at the upper end of NESO's indicated 2.7–7.7 GW range; consultation closed 14 August 2026, final awards expected in autumn 2026; a decision on a second window by 2027. The regime is modelled on the interconnector cap-and-floor that financed c. 5 GW of GB interconnection (Nemo Link, NSL, Viking Link, IFA2 and Greenlink; Ofgem). On gas storage: DESNZ, Gas System in Transition: Security of Supply, interim response (18 August 2026) — 56% of respondents doubt the market will respond without further incentives; the Government accepts long-term support may be required; cap-and-floor the model infrastructure operators most commonly favoured (no single model emerged as a clear preference), with respondents' views on a strategic reserve reported and "minded-to" positions to follow. Centrica (article by chief executive Chris O'Shea, 4 September 2026): Rough "practically empty" and set to close by spring 2027 without a support framework; c. £2bn of investment offered under a regulated model.

6. SMMT registrations data (battery-electric c. 20% of new car sales in 2024; 26.2% in January–September 2026, 28.3% in September, against the 33% headline ZEV-mandate requirement for 2026, before flexibilities); Zapmap public charging statistics (c. 87,800 public devices at end-December 2025, up 19% in a year, against DfT's 2022 expectation of at least 300,000 by 2030). Segment utilisation and break-even figures in the chart are indicative Dalmore estimates drawing on operator disclosures; public charging bears 20% VAT against 5% on domestic electricity (zero-rated from October 2026 to March 2027).
7. HM Government, October 2024: up to £21.7bn over 25 years for Track-1 CCUS clusters (HyNet, East Coast Cluster); the East Coast Cluster's first projects reached financial close in December 2024 and Liverpool Bay CCS (HyNet) in April 2025. Revenue models: Transport and Storage Regulatory Investment (TRI) model, Industrial Carbon Capture contracts, Dispatchable Power Agreements, and low-carbon hydrogen agreements.
8. UK ETS free allocation is being phased out from 2027, on an indicative nine-year trajectory, for sectors covered by the UK Carbon Border Adjustment Mechanism, which takes effect on 1 January 2027 (aluminium, cement, fertiliser, hydrogen, iron and steel); together they progressively transfer cluster revenues from contract support to the carbon price (UK ETS Authority, UK Emissions Trading Scheme Free Allocation Review: Main Authority Response, November 2025, p. 5).
9. UK SAF Mandate: 2% of jet fuel in 2025, 10% by 2030, 22% by 2040. Sustainable Aviation Fuel Act 2026 (Royal Assent 5 March 2026) provides for the revenue certainty mechanism — two-way strike-price contracts with a designated counterparty, funded by a levy on aviation fuel suppliers (Act, ss. 1 and 6); DfT's contract allocation strategy (July 2026) opens the first allocation round in the first quarter of 2027, with awards targeted for late 2028, up to 230 kilotonnes a year, on contracts assumed to run 15 years.
10. International Maritime Organization: net-zero framework combining a global fuel standard and greenhouse gas pricing, approved at MEPC 83 (April 2025). Adoption was adjourned for twelve months at the extraordinary session on 17 October 2025 (57 votes to 49 on a Saudi-tabled motion, as widely reported, with the United States opposing the framework); the adjourned session is scheduled to resume on 4 December 2026, after MEPC 85, and adoption requires a two-thirds majority of parties present and voting.
11. Sizewell C: final investment decision 2025, financed under a regulated asset base with government and private investors; capital cost of c. £38bn (2024 prices). Great British Energy — Nuclear selected Rolls-Royce SMR as preferred bidder for the small modular reactor programme (June 2025) and Wylfa, Anglesey, as the first site (November 2025), and in April 2026 signed a contract with Rolls-Royce SMR for three units there. Contrast: Hinkley Point C's CfD strike of £92.50/MWh (2012 prices; £89.50/MWh following the Sizewell C FID) reflected construction risk priced into a contracted power price.
12. Industry reporting on transition supply chains: HVDC cable and converter manufacturing capacity reserved years ahead (for example, SSEN Transmission's 2023 capacity reservation agreements with NKT and Hitachi Energy); large power transformer lead times averaging c. 2.3 years and up to c. 4 years for the largest units (Wood Mackenzie, April 2024; US/global data); constrained global fleets of cable-lay and heavy-lift installation vessels. NESO (October 2025) separately reports lead times of six to ten years for some key power-system projects.

13. Transition Plan Taskforce (TPT) Disclosure Framework, October 2023; the IFRS Foundation assumed responsibility for the TPT's disclosure-specific materials in 2024 (announced June 2024). 'Enabling activities' follows the concept in Article 16 of the EU Taxonomy Regulation (2020/852): activities that directly enable others to make a substantial contribution to an environmental objective. Sustainability claims of this kind fall within the scope of the FCA's anti-greenwashing rule (ESG 4.3.1R) and must be fair, clear and not misleading.



Alder Castle
10 Noble Street
London
EC2V 7JX

Caledonian Exchange
19A Canning Street
Edinburgh
EH3 8EG

+44 (0)20 3372 0490

