



The Investable Transition: why the energy transition will happen at the speed of economics, and why that is good news for infrastructure investors

THE DALMORE INFRASTRUCTURE SERIES

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The energy transition is the largest reallocation of capital in a generation — some \$2.3 trillion a year globally, and some £50 billion a year in the UK alone by 2030. Alistair Ray, Chief Investment Officer of Dalmore Capital, argues that the transition will happen at the speed of economics, not ambition — and shows why, for infrastructure investors, that is the good news.

1. KEY POINTS

- The transition will only happen to the extent that it works economically: capital at this scale — some \$2.3 trillion a year globally, around £50 billion a year in the UK by 2030 — is not donated but invested, and it expects a return.
- The evidence supports optimism, not anxiety: where the economics were made to work — offshore wind, electric vehicles, solar — deployment has consistently beaten forecasts; where policy leaned on subsidy against unreformed economics, it has stalled.
- Subsidy cannot carry a whole-economy transition: the levies that carried the first tranche of renewables — a tenth of the transition — run at around £12 billion a year, shifted in part from bills to taxpayers in 2026 but not reduced; support at that intensity across the whole programme would compound into a bill no government could raise, and revenues resting on perpetual political generosity carry a repeal risk that markets systematically underprice.
- A fixed price is not inherently a subsidy: a contract-for-difference is a two-way hedge — offshore wind generators paid money back to consumers through the 2021–22 price spike — and competitively discovered price certainty is how infrastructure has always been financed.
- The Dalmore test sorts the transition in two questions: does the asset earn its return at market or regulated prices with carbon reasonably priced — or is its support competitively allocated, falling over time, and on a credible path to standing alone? Assets that pass neither are policy speculation, whatever their labelling.
- Applied across the map — networks, industrial decarbonisation, aviation and shipping fuels, EV charging, storage, adaptation — the test reveals an opportunity set larger and more diverse than a renewables-only lens suggests, including routes where the downside is floored or a traditional business carries the transition upside.

2. EXECUTIVE SUMMARY

The energy transition is the largest reallocation of capital in a generation: some \$2.3 trillion a year globally, and around £50 billion a year in the UK alone by 2030.¹ The great majority of that money must come from private investors, which leads to a conclusion that is stated surprisingly rarely: **the transition will only happen to the extent that it works economically**. Capital at this scale is not donated. It is invested, and it expects a return.

The evidence supports optimism, not anxiety. Where the economics have been made to work — offshore wind through competitive fixed-price contracts, electric vehicles through falling battery costs, solar almost everywhere — deployment has consistently beaten forecasts. Where policy has leaned on subsidy against unreformed economics — hydrogen for home heating, grant-funded deep retrofit — it has consistently stalled. The lesson is not that the transition is failing; it is that the parts designed around sound economics succeed, and the parts designed around wishful economics do not.

Subsidy cannot carry a whole-economy transition. The levies that carried the early renewables build-out — a tenth of the transition, at most — run at around £12 billion a year, whether collected on bills or, as in part since 2026, from taxpayers; the investment requirement is £50 billion a year for decades, and support at the same intensity across it would compound into a bill of the order of £75–100 billion a year.² Subsidy at that scale is fiscally impossible and

politically fragile: Spain's retroactive solar cuts, Britain's windfall levy on generators, and the partial unwinding of the US Inflation Reduction Act all teach the same lesson — revenues that depend on perpetual political generosity carry a repeal risk that markets systematically underprice.³ A contract-for-difference, by contrast, is not inherently a subsidy: it is a two-way fixed price, the oldest financing structure in infrastructure — and when market prices spiked in 2021–22, wind generators paid money back to consumers.⁴

Our house view follows. Dalmore believes a long-term infrastructure investment is only sound if it passes one of two tests: it earns its return at market or regulated prices with carbon reasonably priced — or there is a clear strategic reason for the support it receives, such as an early-stage asset descending a learning curve, with support that is competitively allocated, falling over time, and carrying a credible path to standing on its own. Assets that pass neither test may still be infrastructure in every physical sense, but they are not sound infrastructure, and they deserve neither the infrastructure premium nor the core-infrastructure capital that goes with it — they are policy speculation, and should be priced as such. Applied across the transition — grids, industrial decarbonisation, aviation, shipping, carbon capture, storage, adaptation — this test reveals an opportunity set that is large, diverse and, in places, strikingly under-capitalised. This paper sets out the test; the two that follow apply it.

3. THE LARGEST REALLOCATION OF CAPITAL IN A GENERATION

Global investment in the energy transition reached a record \$2.3 trillion in 2025, up 8% on the year — roughly double all upstream oil and gas investment — and it is still rising.¹ In the UK, the Climate Change Committee puts the economy-wide requirement at around £50 billion a year by 2030, sustained for two decades: generation, networks, storage, industrial conversion, transport, buildings. The Government's own infrastructure strategy assumes the substantial majority is privately financed.

For infrastructure investors this is, straightforwardly, the opportunity of a career: an entire energy system being rebuilt, most of it requiring precisely the patient, yield-seeking capital that pension funds and insurers exist to provide. But the scale carries an implication that much transition commentary skips past. Money at this scale cannot be conscripted or financed principally by subsidy; most of it must be attracted on investable terms. Which means every serious conversation about the transition is, whether it admits it or not, a conversation about returns. Countries that internalise this are more likely to build faster and cheaper than those that treat economics as an obstacle to ambition rather than the mechanism of it.

4. TRANSITIONS MOVE AT THE SPEED OF ECONOMICS

The past decade offers a controlled experiment, because Britain has run both strategies side by side.

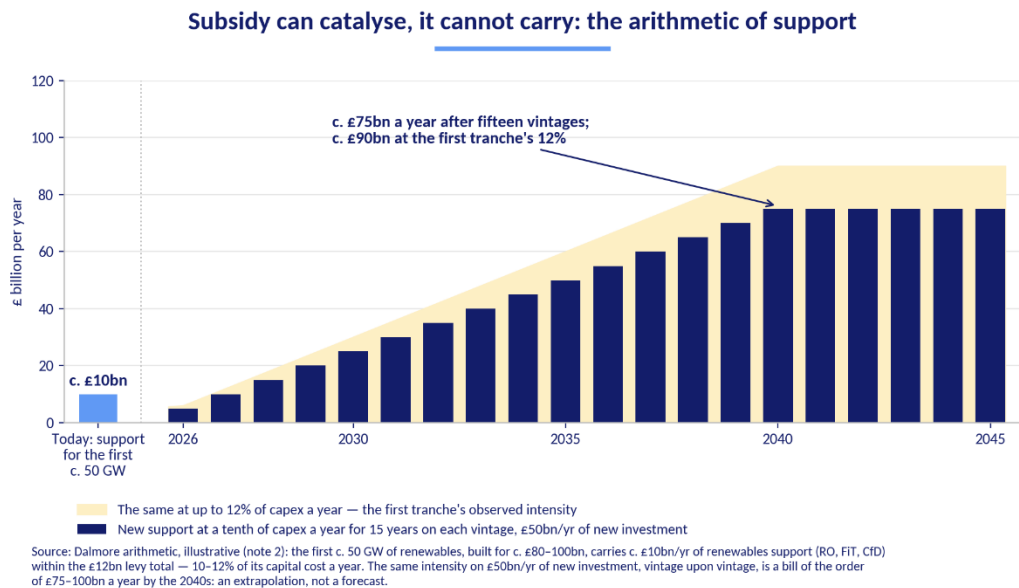
Where the economics were made to work, deployment has been remarkable. Offshore wind grew from an expensive curiosity to the backbone of the power system as competitive auctions drove contracted prices from £150/MWh to below £40 at the 2019 low.⁵ Electric vehicles are a genuine consumer success: more than one in four new cars sold in Britain in 2026 is fully electric, driven not by mandate alone but by battery costs that have fallen roughly 90% since 2010 and total running costs approaching parity with petrol.⁶ Solar deploys at pace wherever grid connections allow. In each case the pattern is identical: policy corrected a market failure — price risk, scale, early cost — and then demand did the work.

Where the economics were not made to work, no amount of ambition has substituted. Hydrogen for home heating has been quietly shelved after cancelled trials — by 2026 the Government's own description was “not yet a proven technology”, with any future role “likely to be limited”. Heat pump uptake runs at a small fraction of what any net-zero pathway requires — and in January 2026 the Government replaced its target of 600,000 installations a year by 2028 with 450,000 by 2030 rather than close the gap — for reasons of household economics that the companion paper Heating Britain examines in detail.⁷ And instructively, even within success stories the pattern holds at asset

level: EV *adoption* has flourished while much public EV *charging* has struggled to earn its cost of capital — utilisation outside prime locations remains too low to cover heavy grid-connection and hardware costs, and operators dependent on assumed future demand have absorbed painful losses.⁶ The vehicle fleet turned over because the consumer economics worked; the charging estate is finding its economics site by site. Same sector, same policy tailwind, opposite investment outcomes — the difference, in every case, is whether the revenue line stands up without heroic assumptions.

5. WHY SUBSIDY CANNOT CARRY IT

None of this is an argument against public support — it is an argument about arithmetic and durability.



The arithmetic first — and it is an arithmetic of support, not of capital, because support only ever bridges the gap between what an asset earns and what it costs. The levies that carried the early renewables build-out — some 50 gigawatts of capacity, perhaps £80–100 billion of investment over two decades — run at around £12 billion a year, of which more than half is the legacy cost of that first tranche.² Since April 2026 roughly three-quarters of that legacy cost has been shifted from bills to general taxation for three years, and from October 2026 VAT has been lifted from household electricity for six months — but moving a cost to the Exchequer does not shrink it. That first tranche was a tenth of the transition. Support at the same intensity — call it a tenth of capex a year, for fifteen years, on every vintage — applied to £50 billion of new investment every year for two decades would compound, vintage upon vintage, into a bill of the order of £75–100 billion a year by the 2040s — an extrapolation of today's support intensity rather than a forecast, but one that makes the point: fiscally impossible and politically unsurvivable. The overwhelming majority of transition capital must earn a market return. Subsidy can catalyse; it cannot carry.

“Subsidy can catalyse; it cannot carry.”

— Alistair Ray, Chief Investment Officer, Dalmore Capital

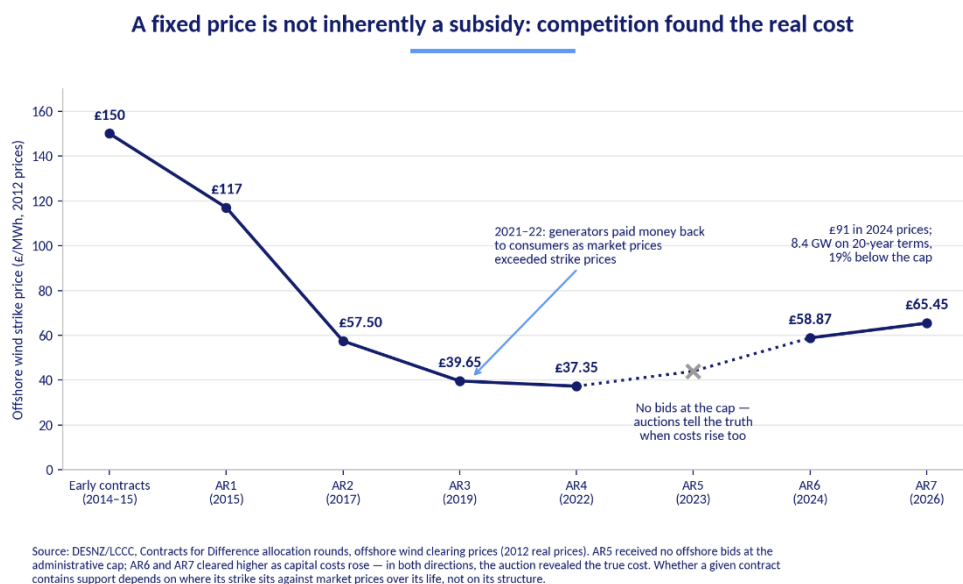
Durability matters more. A revenue line that exists because a government wills it can cease to exist the same way, and the historical record is unkind: Spain retroactively cut tariffs for operating solar plants after 2010, destroying equity

that had been invested in good faith; Britain imposed the Electricity Generator Levy on renewable generators in 2023 — prospective and time-limited, and so a milder case than Spain's retroactive cuts, but a reminder that windfall regimes arrive when politics demands them. The 2025 proposal to freeze Renewables Obligation and Feed-in Tariff indexation at 2025/26 levels showed the same instinct at work in Britain: generators and investors, Dalmore among them, objected; the Government set the freeze aside but still moved existing assets from RPI to CPI indexation from April 2026 — a smaller retrospective change, but a retrospective change nonetheless. The risk was reduced, not removed. Nor is the instinct confined to Europe: the United States is partially unwinding the Inflation Reduction Act's credits within four years of enactment.³ Britain's own 2026 bill measures make the same point from the opposite direction: a levy shifted to the taxpayer for three years, and a six-month VAT cut funded by the cancellation of an unrelated programme, are support that one announcement switched on and the next can switch off. We draw a precise conclusion, not a cynical one: the more an asset's value depends on *continuing discretionary generosity*, the larger the unpriced political risk on its balance sheet. Long-term infrastructure — assets with 30- and 40-year lives — cannot be built on 4-year revenue politics. This is why significant, open-ended subsidy is not merely expensive; for an investor, it is structurally unreliable.

This is not an argument that economics should replace policy. On the contrary: the greatest successes of the transition have occurred where policy corrected a market failure — and then allowed competition and private capital to do the rest. The objective of policy is not to override economics but to improve it. The next section shows what that looks like in practice.

6. A FIXED PRICE IS NOT INHERENTLY A SUBSIDY

The distinction the subsidy debate usually misses is between *price support* and *price certainty*. They look similar — both involve a government contract — and they are economically opposite.



“The mechanism tells the truth in both directions, which is precisely its value.”

— Alistair Ray, Chief Investment Officer, Dalmore Capital

A contract-for-difference is a two-way fixed price. When the market price is below the strike, the generator receives a top-up; when it is above, the generator pays the difference back — as offshore wind generators did through the 2021–22 price spike, returning money to consumers.⁴ With wholesale power averaging above £80/MWh in 2025 — above the strikes of the 2019 and 2022 rounds in today's money — and higher again through the gas-price shock that followed the closure of the Strait of Hormuz in March 2026, the arithmetic of those contracts points the same way again — though whether a given round was a net payer in any period turns on hourly reference prices and eligible output, and the position is a matter of LCCC's published payment data rather than assertion here.⁴ Whether any subsidy is present depends entirely on where the strike sits relative to market prices over the contract's life, and that is exactly what competitive auctions ground away: from £150/MWh in the early contracts to £37–40 by 2019–22 — at which point the contracts became what they always were structurally: a price hedge, not a transfer.⁵ Whether a particular contract contains support is a question about its strike, not its structure: the £150 contracts of 2014 contained a great deal; AR7's £91 — in 2024 prices, set against a 2025 wholesale average above £80 in money of the day — sits close to the market it will be measured against; what it contains over twenty years depends on where wholesale prices settle, which no single year's average can establish. The structure is identical in both — and it is the structure, not the strike, that this section defends. The 2023 auction that attracted no bids, the 2024 round that cleared higher as capital costs rose, and the 2026 round — a record 8.4 GW of offshore wind at £65/MWh in 2012 prices (£91 in today's money), on 20-year terms and a fifth below the administrative ceiling — complete the picture: the mechanism tells the truth in both directions, which is precisely its value.⁵

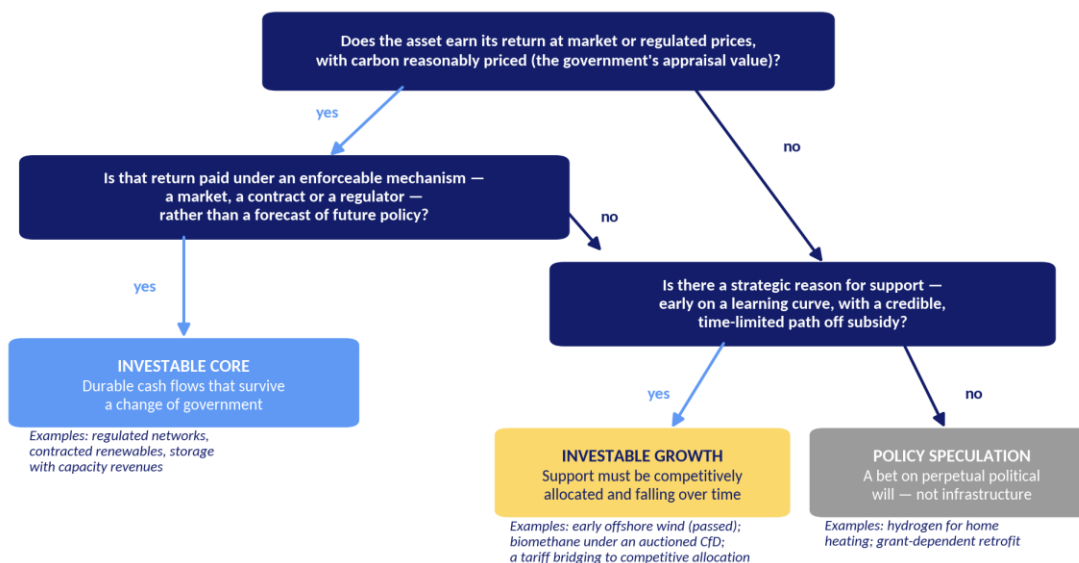
The honest objection to the offshore wind story is not the contract but the wires. The strike price is the generator's cost, not the system's: the transmission needed to carry Scottish wind to English demand has not been built at the pace the auctions filled the pipeline, and the bill for the gap is paid outside the CfD — in constraint payments to turn wind down and gas up, which reached about £1.5 billion in 2025, are running a third higher in 2026, and on the Government's own delivery plan go on rising to a peak around 2030 before the Eastern Green Links and the onshore reinforcements behind them land.⁵ None of that is an argument against the mechanism. It is the strongest argument there is for the network build-out that the next paper calls the backbone trade, and for the locational signals that connection reform has begun to supply. But a reader who prices offshore wind at £91 and stops there has priced the generator and not the system — and this series does not.

Nor is a fixed price a departure from market economics. It is how infrastructure has always been financed: regulated water and network returns, availability-based PPPs, power purchase agreements. Nobody calls a water company's regulated asset base a subsidy. What these structures share is correct risk allocation — moving multi-decade price risk away from the party least able to bear it — and since the cost of capital is the dominant cost of any capital-intensive asset, correct risk allocation is the cost reduction. A substantial share of offshore wind's famous cost decline came not from turbines but from exactly this: de-risked revenues cutting the discount rate.⁸ The policy lesson generalises, and it is a constructive one: governments do not need bigger subsidy budgets to mobilise transition capital — they need to extend price certainty, competitively allocated, to the sectors still waiting for it. The investor lesson generalises too: contracted and regulated revenues at market-discovered levels are the most durable in the asset class, because they are the ones no Treasury is itching to claw back.

7. THE DALMORE TEST

Our house view distils into a two-question test, applied before anything else we do. One clarification matters before the test is stated: it does not decide what is and is not infrastructure — plenty of high-risk, policy-dependent assets are infrastructure in every physical sense. It decides what counts as sound infrastructure: what deserves the infrastructure premium, and the core-infrastructure capital that comes with it.

The Dalmore test: two ways to be investable, one way not to be



Source: Dalmore. 'Carbon reasonably priced' uses the government's own appraisal value (£280/tCO₂e in 2030, 2020 prices) rather than the traded ETS price — a test of economic merit; underwriting counts only revenues someone is obliged to pay. A transparently funded, time-limited tariff where no pipeline yet exists to compete counts as a path off subsidy.

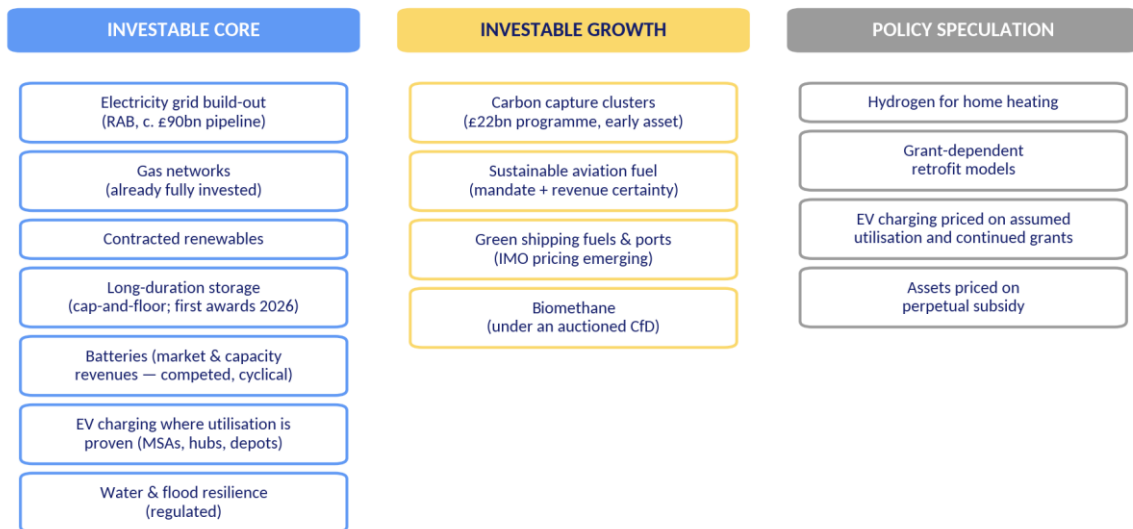
First: does the asset earn its return at market or regulated prices, with carbon reasonably priced? This is a test of economic merit, and for it we use the government's own appraisal value of carbon — £280 per tonne in 2030, in 2020 prices, or roughly £350 in today's money — rather than the traded ETS price, because it is the value government itself uses to decide what to support, and so the best available guide to where policy is heading.⁹ It is not a revenue line. Underwriting uses only revenues that someone is obliged to pay — a market, a contract or a regulator — and treats any future carbon price above today's as upside rather than base case; the investor's question is always who pays, under what enforceable mechanism, and whether that revenue justifies the capital and the risk. Assets that pass on both counts are the investable core: regulated networks, contracted generation, storage earning market and capacity revenues. Their cash flows survive a change of government, which for a 30-year asset is the risk that matters most.

Second, for assets that do not yet pass: is there a strategic reason for support? Early assets descending a learning curve are the legitimate case — offshore wind in 2015 was exactly this, and the support that carried it was defensible because it was competitively allocated, fell over time, and carried a visible path to standing alone. That is the template, and two clarifications keep it honest. "Standing alone" means at market prices with carbon priced: an asset whose economics close once the carbon it displaces is paid for, as the Government's own valuation says it should be, has a path — and the policy that creates that price is the destination, not a subsidy. And an administratively priced tariff is legitimate as a bridge where no pipeline of projects yet exists to compete: France built its biomethane market on one before moving to auctions, and the auction it tried too early failed — provided the tariff is transparently funded and carries a sunset into competitive allocation. Support that is grant-based, priced by officials indefinitely, or without a sunset fails the template — not because subsidy is wicked, but because it neither reveals costs nor builds toward its own redundancy. Greening the Molecule applies both clarifications to the asset that needs them most. Assets that pass neither test — whose models require perpetual political will — remain infrastructure in form, but they are not sound infrastructure: they are policy speculation, whatever their ESG labelling, and we avoid them. The test is deliberately symmetrical: it will rule out some assets fashionable in transition portfolios, and rule in some that are unfashionable. That is rather the point.

8. THE TEST APPLIED ACROSS THE TRANSITION

Applied sector by sector, the test sorts the transition into a rich and genuinely investable map — with far more opportunity than a renewables-only lens reveals.

The test applied across the transition



Industrial decarbonisation spans all three: ETS- and CBAM-driven fuel switching is core; cluster infrastructure is growth; processes with no credible route off subsidy are speculation. Pure public-good adaptation is government's job — the investable share sits inside regulated utilities.

Source: Dalmore. Placement reflects the revenue model today, not asset quality or return volatility: market revenues and a regulated floor are both 'core' on this test with very different risk. Assets move left as support is competed away.

Electricity networks are the purest core asset in the transition: Ofgem's December 2025 settlement approved £28.7 billion of upfront network investment for 2026–31 within a pipeline of roughly £90 billion, of which electricity transmission alone could reach some £70 billion as projects are released through in-period mechanisms — all under the RAB model, with distribution behind it, and all regulated returns on a build-out that is necessary under every scenario.¹⁰ Nor is the door narrowing: in September 2026 the Government created Great British Grid, a publicly owned network company that will compete for tendered transmission projects alongside private capital rather than take the incumbents into public ownership — a state bidder whose arrival commits the Government to more competitive tendering, not less.¹⁰ The complement is less often stated: Britain's **gas networks are already fully invested** — the pipes are in the ground, the iron-mains replacement programme is deep into its final phase, and Ofgem's accelerated depreciation means today's broad customer base is paying the capital down now.¹¹ One network needs vast new capital and offers regulated growth; the other needs far less — maintenance, replacement and connection works, and in time decommissioning, rather than expansion — and offers depreciating-asset cash yields plus option value on green gas. Both pass the test; they simply pay differently. The transition's cheapest asset is the one that is already built — a distinction developed fully in the companion paper Heating Britain.

Industrial decarbonisation spans all three columns. Fuel switching and efficiency driven by the UK ETS — reinforced from 2027 by a carbon border adjustment that protects industry from being undercut by unpriced imports — is core: the carbon price is the revenue line.¹² Cluster infrastructure — the pipes and stores of **carbon capture**, backed by the Government's £22 billion, 25-year commitment to the first two clusters — is the growth column's textbook case: genuinely early assets, strategically supported, with contracted revenue models designed to hand over to the carbon price as it rises.¹³ Processes with no credible route off subsidy sit in the third column, and honesty requires saying so.

Aviation and shipping are earlier on the same road, and both are moving in the direction the test rewards. The UK's sustainable aviation fuel mandate — 10% by 2030, rising thereafter — creates obligated demand, and the revenue-certainty mechanism legislated in March 2026 — a guaranteed strike price, with the first allocation round opening in 2027 — is, in effect, a CfD for SAF plants: price certainty, not grant.¹⁴ Shipping went further than any sector expected, and then stalled: the International Maritime Organization approved the first genuinely global emissions pricing regime in April 2025, saw its adoption adjourned for a year that October under American and Saudi pressure, and returns to the vote in December 2026.¹⁵ If it passes, green fuels and port infrastructure convert from policy bets into assets with a worldwide revenue standard; if it fails again, the regional carbon regimes carry the structure forward more slowly. Both sectors are for now investable growth rather than core — but they are building the right structures, and early-mover infrastructure (fuel production, bunkering, airport and port logistics) will be scarce when the mandates bind.

Electric vehicle infrastructure illustrates the test's discipline inside a success story. The fleet transition passes easily — consumer economics did the work. Public charging passes *selectively*: where utilisation is demonstrated (motorway service areas, urban hubs, fleet depots), revenues underwrite the asset; where models rest on assumed future utilisation and continued grant support, the assets are still infrastructure but the investment case is speculation — to be priced as speculation, not at the infrastructure premium. The sector's early losses are not an indictment of the theme but a repricing of it — and repriced entry into an asset class whose demand curve is genuinely secular is precisely the kind of opportunity disciplined capital waits for.⁶

Storage and flexibility pass the test with increasing comfort: batteries earn stacked market revenues today; long-duration storage has its first cap-and-floor awards in prospect, Ofgem having signalled in June 2026 that it is minded to contract sixteen projects and 7.6 GW, on terms still being settled — risk allocation again, not subsidy; and seasonal gas storage acquires contractable insurance value in any system honest about rare-event demand — a point the Government conceded in 2026, accepting that the market will not fund storage unaided and recording cap-and-floor as the operators' preferred instrument, while the country's largest store sat near-empty through a gas-price shock.¹⁶

A fourth pattern deserves naming, because allocators increasingly ask for it: transition exposure with a floored downside, or with a traditional business underneath. Some of the most investable transition opportunities are not pure-play new build but assets where an established revenue line carries the investment while the transition upside accrues. The motorway service area is the cleanest example: today's fuel, retail and parking revenues fund the charging forecourt it is steadily becoming, so the investor is paid to wait for the fleet to arrive rather than paying today for the assumption that it will. The fully invested gas network is another — regulated, depreciating-asset cash yields now, option value on green gas later. And the cap-and-floor family converts merchant exposure into a bounded band: the downside is not a forecast but a floor, contractual or regulated. For capital wary of paying growth prices for policy hope, this floored-and-optional route into the transition is among the most underrated doors the map offers — and it is where the series' preference for entitlement over forecast pays most visibly.

Adaptation deserves its place in any serious transition paper, because a warming climate must be paid for twice — once to slow it, once to live with it. The test clarifies where private capital belongs. Pure public goods — coastal defence, catastrophe response — are government's job and should stay so. But the largest investable share of adaptation already sits inside regulated utilities: the water sector's record £104 billion 2025–30 programme includes substantial resilience spending — reservoirs, flood mitigation, network hardening — earning regulated returns.¹⁷ Adaptation is not a rival to the transition for investors; properly structured, it is more core infrastructure.

9. WHAT THIS MEANS FOR INVESTORS — AND WHAT FOLLOWS

The reading of the transition offered here is deliberately optimistic, because the evidence supports optimism. The parts of the transition built on sound economics are not merely surviving — they are the fastest-growing infrastructure markets in the world, and the structures that made them work (auctions, CfDs, RABs, caps-and-floors) are steadily being extended to the sectors that still lack them — as they were in 2026 to sustainable aviation fuel and long-duration storage, and as green gas, shipping fuels and seasonal storage still await. Each extension converts a policy theme into an investable asset class, usually before generalist capital notices. For investors with the discipline to

distinguish price certainty from price support — and the patience to arrive early — the opportunity set is as broad as the asset class has ever offered.

“The gap between fashion and economics is where returns live.”

— Alistair Ray, Chief Investment Officer, Dalmore Capital

The test also tells us where to look hardest: at assets everyone else has sorted by fashion rather than by economics. Some fashionable assets are policy speculation rather than sound infrastructure; some deeply unfashionable ones — a fully-invested gas network, a biomethane plant awaiting its CfD, a repriced charging portfolio — pass the test comfortably. The gap between fashion and economics is where returns live.

This framework stands alone; two companion papers extend it. The second examines the uncontested build-out: the assets required under every credible transition scenario — networks, storage, flexibility, transport and industrial infrastructure — where the investment case does not depend on winning any forecast dispute. The third turns to the hardest and most contested question in the British transition — the decarbonisation of heat — and tests what the economics-first principle implies in practice: a two-network answer that may be cheaper, faster and more politically durable than the current strategy. Together they make a single argument: **the transition Britain can actually build is the one that works economically — and it is thoroughly investable.**

10. 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.

11. NOTES AND REFERENCES

1. BloombergNEF, Energy Transition Investment Trends 2026 (January 2026): global transition investment reached a record \$2.3 trillion in 2025, up 8% on 2024. UK requirement: Climate Change Committee estimates of c. £50bn/yr economy-wide investment by 2030, cited in House of Commons Library, The UK's Plans and Progress to Reach Net Zero by 2050 (2025); HM Government, UK Infrastructure: A 10 Year Strategy (2025) assumes the majority is privately financed.
2. OBR, Economic and Fiscal Outlook, environmental levies: c. £12bn/yr, of which Renewables Obligation legacy costs are c. £7bn; Capacity Market, CfD top-ups, GGSS and social tariffs make up the balance. Autumn Budget 2025 (26 November 2025): from 1 April 2026, 75% of RO costs are met from general taxation for three years and the Energy Company Obligation ends — the “£150 off bills” package. HM Government, 21 July 2026 (restated with Ofgem's cap announcement of 26 August): VAT removed from household electricity from 1 October 2026 to 31 March 2027 (HMRC, Revenue and Customs Brief 10 (2026); c. £850m, c. £45 per household), funded by the cancellation of the digital ID programme. The levy total is unchanged by either measure; its incidence has moved, temporarily, from bills to taxpayers. Support-intensity arithmetic (author, illustrative): c. 50 GW of renewable capacity accredited under the RO, FiT and early CfDs, built at c. £80–100bn, carries c. £10bn/yr of renewables support (the RO, FiT and CfD elements of the £12bn levy total; the balance is the Capacity Market, GGSS and social tariffs) — roughly 10–12% of its capital cost a year; at a tenth of capex a year for fifteen years, £50bn/yr of new investment adds £5bn/yr of support per vintage, compounding to c. £75bn/yr after fifteen vintages, and c.

£90bn/yr at 12%. This is an extrapolation of today's support intensity across future investment, not a forecast; the point is the order of magnitude, not the figure.

3. Spain: retroactive reductions to solar feed-in tariffs, 2010–2013, subject of extensive Energy Charter Treaty litigation. UK: Electricity Generator Levy, 2023–2028, a 45% levy on exceptional generation receipts; DESNZ, Renewables Obligation and Feed-in Tariffs: consultations on changes to inflation indexation (31 October 2025), and Renewables Obligation: changes to inflation indexation – government response (28 January 2026), confirming a switch from RPI to CPI indexation from 1 April 2026. US: partial repeal and curtailment of Inflation Reduction Act clean energy credits, 2025.
4. Low Carbon Contracts Company data: CfD generators made net payments back to consumers in quarters during 2021–22 when reference prices exceeded strike prices — the two-way contract operating as designed. The 2025 GB average wholesale price exceeded £80/MWh (DESNZ/Energy UK, January 2026), above the AR3 and AR4 strikes in current money (c. £55 and £52/MWh), which on the contract's arithmetic points to difference payments on those rounds running from generator to consumer in the periods when hourly reference prices exceeded the strikes; the actual 2025–26 net-payment position by round is not asserted here and should be read from LCCC's published generator payment data. AR7's £65.45 is a 2012-price strike (£91.20 in 2024 prices); its comparison with a money-of-the-day wholesale average is indicative only. Wholesale gas rose to multi-year highs after shipping through the Strait of Hormuz halted in early March 2026 (NBP roughly doubled within two sessions to above 140p/therm on 3 March, and stood at c. 188p/therm on 2 October 2026).
5. DESNZ/LCCC, Contracts for Difference allocation rounds, offshore wind clearing prices (2012 real prices): early investment contracts c. £150/MWh; AR1 (2015) c. £117; AR2 (2017) £57.50; AR3 (2019) £39.65; AR4 (2022) £37.35; AR5 (2023) no offshore bids at the administrative cap; AR6 (2024) £58.87 as capital costs rose; AR7 (results 14 January 2026) £65.45 for fixed-bottom offshore wind (£64.23 in the Scottish pot; floating £155.37) — £91.20 in the 2024 prices DESNZ now uses — for 8.4 GW across twelve projects (ten fixed-bottom, including Berwick Bank B in the separate Scottish category, and two floating) on 20-year contracts, 19% below the administrative strike price. AR7 as a whole procured a record 14.7 GW across 201 projects, including 4.9 GW of solar at £65/MWh and 1.3 GW of onshore wind at £72/MWh (2024 prices; results 10 February 2026). The AR8 application window opened on 20 July 2026. Constraint costs (NESO constraint breakdown data): constraint payments c. £1.46bn in 2025 — c. £0.38bn paid to wind to reduce output and c. £1.08bn for replacement generation (Octopus Energy 'Wasted Wind' tracker of NESO data; The Times); thermal constraint costs of £1.38bn for 1 January–8 November 2026, 37% above the same period of 2025 (NESO). The Clean Power 2030 delivery plan (April 2026) projects constraint costs peaking around 2030 and falling as new transmission commissions; Eastern Green Link 1 (2 GW, Torness–Hawthorn Pit) and Eastern Green Link 2 (2 GW, Peterhead–Drax) are targeted for 2029.
6. SMMT registrations data: battery-electric vehicles c. 20% of new UK car sales in 2024; 26.2% of registrations in January–September 2026 (28.3% in September, a record month) against a 33% ZEV-mandate requirement for 2026; battery pack prices down c. 90% since 2010 (BloombergNEF). Zapmap: c. 88,500 public charging devices at January 2026, up 19% in a year. Public charging economics: operator profitability constrained by low average utilisation outside prime sites, heavy grid connection costs, and the 20% VAT rate on public charging versus domestic electricity (5%, and zero-rated from October 2026 to March 2027) (industry reporting; Zapmap/ChargeUK data). A pay-per-mile charge on electric cars (3p/mile) was confirmed in Autumn Budget 2025 to apply from April 2028.
7. See Heating Britain: The Case for a Two-Network Transition, for the full analysis of heat pump economics, the hydrogen-for-heating trials, and the two-network alternative. Warm Homes Plan (January 2026): 450,000 heat pump installations a year by 2030 (250,000 in existing homes, 200,000 in new build), replacing the 2021 ambition of 600,000 a year by 2028; hydrogen heating “not yet a proven technology” with a role “likely to be limited”. DESNZ hydrogen heating policy update (24 March 2026) restated that position and deferred a decision to a future consultation. MCS: just over 60,000 certified heat pump installations in 2025.
8. Analyses of audited project accounts (e.g. Aldersey-Williams et al., Energy Policy, 2019) attribute a substantial share of offshore wind's 2015–19 headline cost decline to cheaper, de-risked capital rather than hardware alone.

9. DESNZ, Valuation of Greenhouse Gas Emissions for Policy Appraisal: central carbon value £280/tCO₂e in 2030 (2020 prices; low £140, high £420), used across government cost-benefit analysis — roughly £350 in 2026 prices once uprated with the GDP deflator, as the guidance requires when comparing with costs in current prices; the traded UK ETS price has been far lower, c. £35–70/t, with UKAs at c. £62/t at the end of September 2026. Negotiations to link the UK and EU schemes, formally opened in January 2026, were unresolved at the time of writing, the two sides having pledged in late September to complete a linkage agreement by their next summit.
10. 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 rounds to “£28 billion”), within a wider investment 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 — the largest network build-out since the 1960s, remunerated under the regulated asset base model. The price control took effect on 1 April 2026; SSEN Transmission accepted its determination in March 2026. Great British Grid (announced 29–30 September 2026): a publicly owned network company within Great British Energy, to “bring together public and private investment” and to compete in the competitive tendering of transmission projects, which the Government undertook to accelerate; no existing assets taken into public ownership; Ofgem and NESO roles unchanged; funding beyond start-up costs to be set at a future spending review. Ofgem's draft CATO licence (consultation to 16 October 2026) provides a 35-year availability-based revenue stream, with a first tender anticipated in 2027. See The No-Regrets Build-Out, Section 2.
11. Ofgem, RIIO-GD3 Final Determination (December 2025): confirmed faster depreciation of gas network investment, with new assets fully depreciated by 2050. The HSE iron mains risk reduction programme runs to 2032 (enforcement period 2026–31); the great majority of the capital stock is in place.
12. UK Emissions Trading Scheme; UK Carbon Border Adjustment Mechanism, commencing 1 January 2027, applying carbon pricing to imports of iron and steel, aluminium, cement, fertiliser and hydrogen. UK–EU ETS linking negotiations (opened January 2026) continued at the time of writing; the EU's CBAM took effect in January 2026.
13. HM Government, October 2024: c. £22bn over 25 years for the first carbon capture, usage and storage clusters (HyNet and the East Coast Cluster), with contracted revenue mechanisms for transport, storage and dispatchable power.
14. 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 — a guaranteed strike price funded by a levy on aviation fuel suppliers; 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.
15. 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 of October 2025 (57 votes to 49 on a Saudi motion, 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.
16. Ofgem, long-duration electricity storage cap-and-floor, Window 1 minded-to decisions (26 June 2026): 16 of the 73 projects assessed (77 were eligible; four withdrew), c. 7.6 GW and 137 GWh at eight to 22 hours' duration — three pumped-hydro schemes, eleven lithium-ion batteries, one compressed-air and one flow battery project; final awards expected in autumn 2026. DESNZ, Gas System in Transition: Security of Supply, interim response (18 August 2026): respondents and the Government doubt the market will maintain gas storage commercially; cap-and-floor was the operators' preferred model, with a strategic reserve under consideration and “minded-to” positions to follow. Centrica (4 September 2026): Rough “practically empty” and set to close by spring 2027 without a support framework. On seasonal gas storage and rare-event system value, see Heating Britain, Section 4.

17. Ofwat, Final Determinations for PR24 (December 2024): c. £104bn of water sector investment 2025–30, including major resilience, storm overflow and supply security programmes. Environment Agency flood and coastal erosion risk management programme: £5.2bn, 2021–27.



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