Leading Sustainability and Regeneration in Projects[1]
Series Article 11

Energy Generation and Distribution: Powering a Regenerative Future[2]

Figure 1 The commons at the mill: a village that owns what powers it, drawing on sun and wind alike — while the snails wait at the barred gate for a grid connection.

Abstract

Every credible pathway to net zero requires Great Britain's electricity system to roughly triple in size by 2050, from around 290 TWh of annual demand today to between 705 and 797 TWh across the National Energy System Operator's scenarios. The technical means to build that system are largely understood. What remains unresolved is the institutional question: who owns the generating assets, who carries which risks, who has visibility of what is happening on the network,

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and who pays when generation and network programmes fall out of step. This article, the eleventh in the series, examines energy generation and distribution as a portfolio of project decisions rather than a set of technologies. It traces the transition through Ørsted's costly first-mover experience and the replication economics of Sizewell C; the grid connection queue that now binds delivery; the 2025 Iberian blackout as evidence that system stability has become a project deliverable rather than an operational afterthought; and the Great British Energy Local Power Plan's wager that community and shared ownership convert public consent and local value into a durable asset. The Derril Water shutdown shows what happens when ownership outruns network readiness. A closure hierarchy — extend, repower, recycle, remove — tests whether "sustainable" was ever meant seriously, with the North Sea's £44 billion decommissioning bill as the cost of closure unplanned. Throughout, the argument maps to the Five Ps, with Peace — energy security — carrying unusual weight.

Keywords: *community energy; energy transition; grid connection; benefits realisation; decommissioning; Local Power Plan; shared ownership; system resilience; Five Ps; regeneration.*

Table of Contents

1. Introduction: a collision between demand and supply

Every serious pathway to net zero in Great Britain requires the electricity system — the grid and the generators that feed it — to roughly triple in size within twenty-five years. This is the arithmetic of the system operator's own published scenarios. The National Energy System Operator's Future Energy Scenarios 2025 puts annual electricity demand at around 290 TWh today, rising to 705 TWh under its "Holistic Transition" pathway, 785 TWh under "Electric Engagement", and 797 TWh under "Hydrogen Evolution" by 2050 (NESO 2025). Peak demand rises from present levels to somewhere between 120 GW and 151 GW. Total installed capacity reaches 439–450 GW. The fourth scenario, "Falling Behind", is the one that misses net zero.

These numbers are also a statement about the portfolio. Tripling a national electricity system in twenty-five years represents a huge opportunity for project managers, and a challenge of a scale the United Kingdom has not attempted since the post-war build-out: commissioning generation, network, storage and flexibility assets at pace, while simultaneously decommissioning the fleet that is reaching the end of its life, and retaining support from the public so it doesn't get undone partway through.

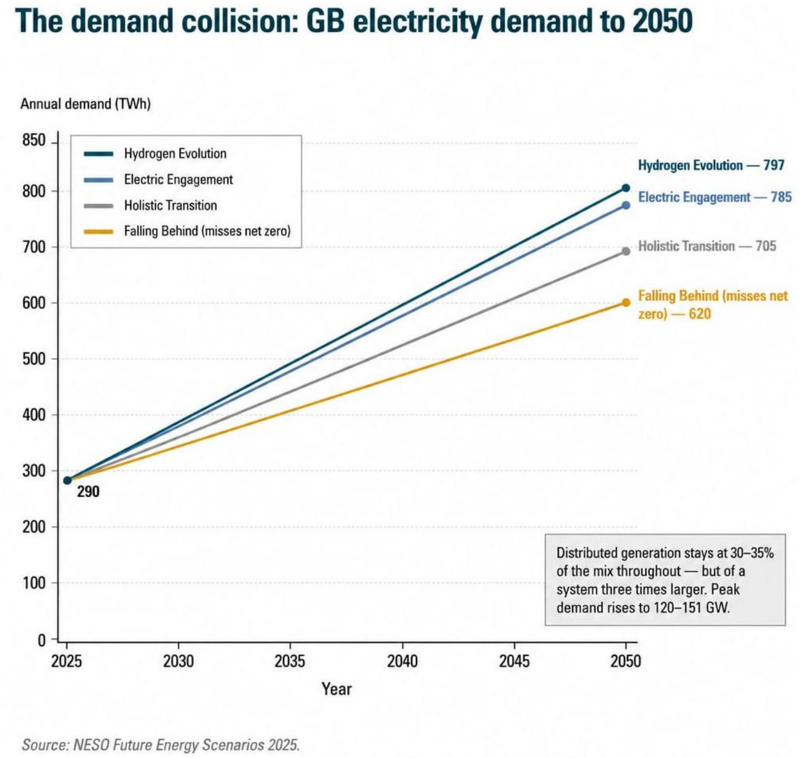

Figure 2 Great Britain's electricity demand to 2050 across the four Future Energy Scenarios pathways. Distributed generation holds its share of the mix throughout — but of a system three times larger.

Article 9 in this series examined one half of the demand collision: the data centres and computational infrastructure whose appetite for firm, clean power is reshaping procurement and siting decisions across the sector (Minney 2026c). This article takes the other half — the generation and distribution system itself — and asks the question this series keeps returning to.

We know how to build these assets. Can we build them so that the communities who host them are measurably better off, the networks that carry their output are ready when they are, and the closure of what they replace is planned and funded rather than coming as a surprise?

The technical transition is largely solved. The institutional transition is not: who owns the assets, who carries which risks, who has visibility of what is happening on the network, and who pays when the sequencing goes wrong. These are project management questions, and they are the ones on which the energy transition will be judged.

2. The transition, not always smooth

This series uses case studies. Rather than reach for a triumphant example every time, we try to show the reality, warts and all. Ørsted is a good place to start.

The boldness of the move that Ørsted took is easy to underestimate from where we stand now. When Henrik Poulsen took over as chief executive of the Danish utility DONG Energy — Danish Oil and Natural Gas — in 2012, the company had just been hit hard by a fall in gas prices, its credit rating had been downgraded, and the outlook was poor (Ørsted 2023). From that position of weakness rather than strength, Poulsen committed the company to dismantling the fossil-fuel business it had been built on and rebuilding around offshore wind. In May 2017 it sold its upstream oil and gas business to Ineos; that autumn it changed its name to Ørsted, after the Danish physicist who first described electromagnetism. A large incumbent chose to walk away from the thing it was good at, before the market forced it to. It became the world's largest offshore wind developer within a decade.

That's an inspiring story, but being the first mover is not always an advantage. Between 2023 and 2025, Ørsted discontinued the Hornsea 4 project in its existing form, incurring approximately DKK 2.9 billion in cancellation fees in the first half of 2025 alone. It took net impairments of DKK 3.6 billion across 2025, concentrated in its United States portfolio and particularly at Sunrise Wind. It completed a rights issue raising roughly DKK 60 billion to repair its capital structure, and divested a 50% equity stake in the 2.9 GW Hornsea 3 project to Apollo for approximately DKK 39 billion, a 55% stake in Greater Changhua 2, and its European onshore business entirely (Ørsted 2026b, 2026a).

By the end of 2025 the company had returned to profit – a profit of DKK 3.2 billion, EBITDA of DKK 25.1 billion excluding cancellation fees and new partnerships (within reporting guidance), interest-bearing net debt reduced to DKK 19.0 billion, more than 10 GW of installed offshore capacity, and 8.1 GW under construction (Ørsted 2026b).

Ørsted was not badly managed. It was early, and being early in capital-intensive infrastructure means carrying interest-rate risk, supply-chain inflation and political risk that later entrants will not carry to the same degree. Poulsen's 2017 gamble paid off because the pivot was structural and hard to reverse; the 2023–25 write-downs are the price of having gone first. A business case that assumes a first-mover advantage should also price in the first mover's discovery costs.

The Hornsea 4 decision is worth reviewing. Hornsea 4 is an offshore wind project, and Ørsted holds consent to build it; walking away was not about the long-term direction of offshore wind. It was about the economics of this project, now: construction-cost inflation, supply-chain pressure and higher financing costs, with a fixed price at which Ørsted had agreed to sell the electricity, changed the equation below the level at which the project could be built for an acceptable return. So the developer stopped. The practical lesson for anyone reading a pipeline of "consented" projects is that a connection agreement and a planning consent are permissions to build, not commitments to build — and when the numbers stop working, even the most capable developer will hand the permission back.

Nuclear, and the economics of doing it twice

The Sizewell C Final Investment Decision, taken in July 2025, is the counterpart lesson: a programme deliberately designed to be a repeat.

The strategic case rests on replication. Sizewell C is described in the Government's own value-for-money assessment as an above-ground replica of Hinkley Point C, and the assessment cites evidence that a construction-ready design and a standardised supply chain — including retained equipment suppliers and personnel — are critical to reducing the risk of schedule and cost overrun in nuclear construction (DESNZ 2025b). Together the two stations would contribute around 6.5 GW; Sizewell C alone is modelled at approximately 3.3 GW of firm power at a 90% load factor over a sixty-year life. At that load factor Sizewell C would generate around 26 TWh in a year, and the Hinkley–Sizewell pair around 51 TWh (the 90% factor already allows for planned outages). Against 700–800 TWh of demand in 2050, the flagship nuclear pair covers well under a tenth of the system — which is part of why the centre of gravity of this article lies elsewhere.

Article 8 in this series examined Hinkley Point C from the perspective of construction-phase socio-economic benefit (Minney 2026b). The interest here is the financing and the second-remove benefit. The Sizewell C assessment models a Net Present Social Value to around the year 2100 of between £3.9 billion and £18.0 billion depending on which regulatory cost threshold is achieved, and which power-demand scenario materialises. It is positive in every core scenario. Once operational, the station is assessed as reducing the cost of a low-carbon electricity system by around £2 billion per year on average (DESNZ 2025b).

But pause for a moment, because this needs to be said. Sizewell C adds *higher* capital costs to the system than the counterfactual of additional onshore and offshore wind supported by flexible generation. The value-for-money case survives because those higher capital costs are outweighed by reduced network, interconnector and balancing costs. Nuclear is a *synchronous* generator: a large spinning mass, physically coupled to the grid, that inherently resists changes in both frequency and voltage and so helps hold the system steady. Wind and solar connect through inverters — power electronics with no such coupling — and, unless deliberately specified otherwise, follow the grid rather than holding it up. Section 4 describes what happens on a system that doesn't have enough of that steadying capability. The point here is that a firm, synchronous generator delivers two things: the electricity, and the stability. The Sizewell C business case captures the first and leaves most of the second un-monetised. This is the second-remove benefit in its clearest form: the benefit is realised somewhere other than where the cost is incurred, in a different organisation's accounts, and it is invisible to any appraisal drawn narrowly around the generating asset itself.

The financing model matters too. Sizewell C is the first nuclear project to deploy the Regulated Asset Base (RAB) model under the Nuclear Energy (Financing) Act 2022 (Nuclear Energy (Financing) Act), which allows the project to draw revenue from consumers during construction rather than accumulating financing costs to be recovered later. Previous analysis estimated that a RAB approach would reduce the present-value cost of building and financing a new nuclear plant by around £30 billion compared with a Contract for Difference (DESNZ 2025b). The consumer-facing consequence is an average of about £1 per month on a typical household bill through the construction period. Around 10,000 jobs are estimated at peak construction.

The DESNZ assessment is candid about what it cannot model. It records as an un-monetised risk that other technologies or financing structures may emerge that lower system costs more than Sizewell C does, and it notes that the modelling excludes air quality, noise, land-use change, biodiversity and construction-phase emissions.

One further observation: on cost and schedule, the modelling is properly probabilistic: it uses Monte Carlo and scenario-based techniques designed to capture how risks combine (DESNZ 2025b). But the strategic security-of-supply risks it lists as un-monetised — extended wind-and-solar droughts, interrupted energy imports, national-security threats to subsea infrastructure — are presented as a menu, with no treatment of their correlation. The real-world scenario is that they arrive together. A still, cold, dark week across northern Europe is precisely when a wind-and-solar drought, peak heating demand and maximum reliance on imports coincide; and the geopolitical hostility that threatens fuel supply and subsea cables is exactly what a climate-stressed world produces more of. Readers of this journal will recognise the failure mode from benefits practice: a risk register that treats combinable risks as independent risks understates the tail. The value-for-money case models correlation where it is mechanically tractable, but reverts to an independence-style list where the authors can't be certain. We return to this under Peace, because it is where the security argument for a diversified, distributed system is strongest.

Table 1 Generation technologies read as project types. The columns that matter most are the last two: the principal delivery risk, and what each asset leaves behind at the end of its life.

Technology	Maturity	Build & capital	Principal delivery risk	End-of-life profile
Onshore wind	Mature	Low capex, 1–2 yr	Planning, grid connection	Repowerable
Offshore wind	Mature, scaling	High capex, 3–5 yr	Supply chain, financing	Repowerable, part-recycled
Solar PV	Mature	Low capex, under 1 yr	Grid connection, land	Recyclable
Nuclear (large-scale)	Mature, slow build	Very high capex, 10 yr+	Cost & schedule overrun	Long-tail liability
Small modular reactor	Pre-commercial	High capex, first-of-kind	Technology, licensing	Long-tail liability

Technology	Maturity	Build & capital	Principal delivery risk	End-of-life profile
Hydro	Mature	High capex, long life	Site, environmental	Very long life / relicense
Tidal	Demonstration	High capex, early	Technology, cost	Recoverable
Geothermal (deep)	Emerging in UK	High capex, drilling risk	Resource, drilling	Well decommissioning

Source: author, drawing on NESO Future Energy Scenarios (NESO 2025).

3. The queue to connect to the grid

The one thing an infrastructure project manager working in Great Britain in 2026 would most like fixed is the grid connection process. It is the binding constraint on delivery.

Ofgem's own statement of the problem is unusually direct for a regulator: there is an oversized connections queue containing an inefficient mix of technologies, significant connection delays, and inconsistent standards of service, and together these are threatening both Clean Power 2030 and wider economic growth (OfGem 2025b). The reform known as TMO4+, approved in April 2025, replaces "first come, first served" with "first ready and needed, first connected". Projects that are speculative, or that hold a place in the queue without the maturity to use it, are deprioritised so the queue becomes a realistic signal of what will actually be built.

By April 2026, three things had become clear that were not clear when the policy was designed (Prestley-Abbott 2026). First, the reformed queue is producing an oversupply of battery projects relative to what Clean Power 2030 requires, and Ofgem is assessing whether to act to encourage early exit; the queue rewarded readiness, and battery projects are quicker to make ready than most alternatives. Second, a number of projects that had been explicitly protected with 2026 and 2027 connection dates will not receive those dates — the protection existed to keep near-term delivery on track, and Ofgem is examining the causes. For anyone holding a schedule against a contracted connection date, they need Ofgem to do this. Third, applications for demand connections (as opposed to supply) — data centres foremost among them — have surged to the point where Ofgem ran a call for input that drew over a hundred responses, including proposals for a levy on data centres to filter speculative applications, alongside a parallel Government consultation on accelerating connections for strategic demand.

Above the queue, a strategic planning layer is taking shape. NESO published a transitional Regional Energy Strategic Plan for electricity in January 2026 (NESO 2026), setting direction for Distribution Network Operators ahead of the ED3 price control, with full Regional Energy Strategic Plans due by 2028. The Centralised Strategic Network Plan methodology has been approved, with a transitional plan due in June 2026 and final plans setting out network build needs for power, gas and hydrogen to 2050 by the end of 2028 (Prestley-Abbott 2026). A decision on the enduring methodology is expected in late summer 2026.

This changes the operating environment in a specific way. Connections to the grid have been reactive up to this point: a project applies, the network operator assesses, the connection is approved or not. Strategic spatial planning inverts that logic, telling developers where the system will accommodate them before they commit development capital. The move from reactive to anticipatory network planning is one of the most significant changes to the environment for energy projects in a generation — and it will not be complete until 2028, which leaves a four-year window in which projects must be delivered against a network plan that is still being written.

Both sides of the meter – the impact of residential storage

A brief note, because the subject belongs to the next article. The system NESO describes is managed on both sides of the meter, and electric vehicles are the reason demand-side flexibility becomes structural rather than marginal. A parked electric car is a battery; a fleet of them is a distributed store whose charging can be shifted in time and whose energy can, with vehicle-to-grid, flow back when the system is short. NESO assesses that this fleet could provide up to 51 GW of flexibility by 2050 — more than the entire gas-fired generation capacity of the United Kingdom as it stood in 2025 (NESO 2025). Article 12 takes up transport; the point to carry forward is that a generation-only view of the energy transition is incomplete by roughly half.

4. Resilience: voltage is the new frequency

At 12:33 Central European Summer Time on 28 April 2025, continental Spain and Portugal lost power. It was the most severe blackout in Europe for twenty years, classified at the highest point on the Incidents Classification Scale. Portugal was restored by 00:22 the following morning; Spain by 04:00.

The final report of the Expert Panel, published on 20 March 2026, repays reading by anyone responsible for energy infrastructure (ENTSO-E 2026a). The rigour and independence of the governance of this report is instructive. The Panel comprised forty-nine members drawn from transmission system operators, regional coordination centres, ACER and national regulatory authorities, and was chaired by experts from two transmission system operators that were unaffected by the event. The affected operators contributed evidence but did not author the findings — a model worth borrowing for any high-consequence project investigation.

The blackout was a voltage event, not a frequency event. The Panel identifies a combination of interacting factors: oscillations, gaps in voltage and reactive-power control, differences in voltage regulation practices between operators, rapid output reductions and generator disconnections in Spain, and uneven stabilisation capabilities. These produced fast voltage increases and a cascade of generation disconnections (ENTSO-E 2026a, 2026b).

Three of the details are widely applicable.

1. How the renewable generators were configured. Under the applicable requirements they were operating in fixed power-factor mode — absorbing reactive power in proportion to their active output rather than responding to what the voltage was doing. They were

compliant, and in aggregate they were not contributing to voltage control at the moment voltage control was what the system needed. This is a specification failure, not an operational one, and specification is where project managers live.

2. Earlier the same day, dispatchers had faced overvoltage episodes and resolved them by manual action within around five minutes. The final episode developed faster than human intervention could contain, and shunt-reactor switching was manual. A system with a rising proportion of inverter-based generation runs on timescales that assume automation, and the control-room procedures had not caught up.
3. This third aspect connects directly to the next section. The distribution operators had no access to actual production data from embedded generators below 1 MW — the rooftop solar that had grown enormously across the Iberian peninsula – and everywhere else. To reconstruct what those installations did during the event, the Panel had to obtain aggregated data from inverter manufacturers. A material fraction of the generation on the system was invisible to the people responsible for operating it.

The Panel's framing of its recommendations is unshowy, a first-of-its-kind event whose remedies are already technologically deployable: strengthened operational practice, improved monitoring, closer coordination and data exchange, and regulatory frameworks that adapt to the evolving nature of the power system. But there's an observation with reach beyond Iberia: developments at local level can have system-wide consequences, and market mechanisms, regulatory frameworks and energy policies must remain aligned with the physical limits of the system (ENTSO-E 2026b).

The resilience frontier has moved. For most of the twentieth century the resilience question in electricity was adequacy: is there enough generation to meet peak demand? That question is now comparatively well handled. The question that replaces it is whether the system has enough stability services — voltage support, reactive power, inertia or its synthetic equivalents, grid-forming rather than grid-following inverter behaviour. These are project deliverables: specified at design, procured through the supply chain, tested at commissioning, and expensive to retrofit. A renewable generation project designed only to produce energy, and not to help hold the system up, has been scoped too narrowly. The challenge grows with the system: distributed generation (the embedded generators below 1 MW) stays at around 30–35% of the mix across every FES pathway, but 30–35% of a system three times the size roughly triples the volume of generation connected below the transmission network, and with it the need for visibility of the location, technology, capacity and operational behaviour of those assets (NESO 2025).

Iberia is what happens when that visibility is absent at national scale. The next section is what it looks like at parish scale.

5. Who owns the wind: ownership as a regeneration mechanism

On 9 February 2026, Great British Energy and the Department for Energy Security and Net Zero published the Local Power Plan. Its central commitment is up to £1 billion of funding to support over a thousand local and community energy projects by 2030, behind a vision of unusual boldness: that by 2030, every community in the United Kingdom will have the opportunity to own a local energy project (GBE and DESNZ 2026).

An evidence annex followed two days later, which sets out in Green Book terms why the intervention is necessary and is candid about the limits of its own evidence (GBE 2026).

How this compares nationally

Community energy in Great Britain is small. There are approximately seven hundred community energy groups. Operational community-owned capacity stands at around 440 MW — roughly 285 MW of solar, 140 MW of onshore wind and 15 MW of hydro. The community pipeline is around 695 MW and the local-government pipeline around 1.2 GW. Historical growth has run at approximately 25 MW per year between 2017 and 2024, much of it a legacy of the Feed-in Tariff, which closed to new applications in April 2019. The annex warns that these figures should not be used for baselining, because no centralised database of the sector exists (GBE 2026).

Set 440 MW against a system heading for 439–450 GW of total installed capacity: roughly 1 MW of community-owned generation for every 1 GW of installed capacity on the system. The annex is clear that the majority of deployment will come from large commercial projects. The case for community energy is therefore not a generation-capacity case. It is about who captures the value the transition creates, and whether the public consents to the transition at all.

Why the sector is small

The GBE report identifies four areas of failure in the annex.

1. **Credit-market failure.** Information asymmetry between community groups and lenders produces credit rationing and adverse selection against organisations lacking collateral, balance sheet and track record. Seventy-two per cent of respondents to the Government's 2024 Call for Evidence identified access to funding and finance as the principal barrier (DESNZ 2025a; GBE 2026).
2. **Grid-connection barrier.** Fifty-eight per cent cited infrastructure and grid connection. The threshold for a Transmission Impact Assessment has been raised from 1 MW to 5 MW in England and Wales, which helps smaller schemes, but upfront connection costs, deposits and milestone payments bear disproportionately on organisations that cannot spread them across a portfolio.
3. **Market-access barrier.** Six large suppliers control 91% of the United Kingdom's retail electricity and gas market (OfGem 2025a), and the fixed costs of wholesale-market access fall hardest on the smallest generators; 38% of respondents cited routes to market. …and…
4. **Coordination failure:** an absence of scalable, replicable business models, with around 60% of respondents citing capacity and capability constraints within their own organisations.

These points are worth holding onto through the rest of the section: community energy is underdeveloped because of identifiable market failures, not because communities lack appetite — which places it in the territory of a market failure to be corrected rather than a niche to be subsidised.

The additionality evidence

Does local ownership produce more local benefit? The GBE annex assembles the evidence.

On local expenditure, SSEN's own regional study found that community energy organisations in its licence areas spent an average of 59% of their expenditure locally — below the UK-wide average of 77%, but still amounting to over £3 million kept in local economies in 2022–23 (SSEN 2025). On economic modelling, a social accounting matrix study of Shetland found that retaining a share of project profits locally — money that would otherwise leak to external investors — raised modelled Shetland GDP by nearly 31% and employment by 9% in addition to the build costs spent locally (Allan, McGregor, and Swales 2011). The mechanism is retention: profit kept in the community is re-spent there, and each round of local spending supports further local activity. It is the same logic that, a few paragraphs below, funds a community bus on Orkney.

The most directly useful evidence for a project-appraisal audience comes from Devon. CAG Consultants modelled a single 30 MW solar farm under three ownership structures — community-owned, commercial developed locally, and commercial developed elsewhere in the United Kingdom — holding the size constant so the community effect and the local effect could be separated (CAG Consultants 2021). The community-owned scheme was assessed as costing Devon County Council around £2.2 million more over twenty years than the local commercial scheme, and around £4 million more than the non-local one (which was cheaper mainly because of lower grid-connection costs). Against that premium, community ownership generated an estimated £15.9 million of additional socio-economic value to the Devon economy — enough to outweigh the extra cost several times over. The study is careful to caveat its own assumption, noting that it deliberately assumed community energy costs more and that for a professionally run, quasi-commercial scheme the differential might be much smaller. This cost premium set against an additionality of community benefit that more than repays should be captured in benefits appraisals. Unfortunately it's often missing in narrow financial assessments in the same way that grid stability might be missed.

On employment, renewable projects support between 0.7 and 5.5 full-time-equivalent jobs per installed MW depending on technology, with community-owned projects creating 1.1–1.3 times more local jobs during construction and 1.1–2.8 times more during operation than equivalent projects owned externally (Lantz and Tegen 2009; Tarhan 2015; WPI Economics 2020). The annex adds a caveat that little research directly evidences whether those jobs are filled by local workers, but the SSEN study (SSEN 2025) gives pointers.

On social license to operate (acceptance) — the theme this series examined in Article 6 (Minney 2025) — community-owned and shared-ownership projects attract higher local support, through perceived fairness in decision-making and benefit distribution rather than the size of the payment (Hogan et al. 2022; Bray et al. 2024; Hogan 2024). On Shapinsay in Orkney, turbine revenue funded a community bus and an electric-car service that reduced island isolation (van der Waal 2020), which was a need identified locally and the same money could have been used for something far less locally relevant.

Thirty-four times more returned to the community – allegedly?

The figure most likely to be quoted from this literature needs care. A study of nine community-owned and four privately owned Scottish wind farms found that community ownership returned an average of around £170,000 per installed MW per year to the local area, against an industry-standard community-benefit payment of around £5,000 per MW — a ratio of roughly 34:1. The Westray turbine returned approximately £299,000 per MW per year (Aquatera 2021).

Two qualifications to be aware of: the study was commissioned by Point and Sandwick Development Trust, an interested party; and it is not a like-for-like comparison: it sets the gross community return from an owned asset — one that had to be financed, built, insured and operated, carrying all of those risks — against a voluntary goodwill payment from an asset owned by somebody else, where there were also profits, they simply were not invested locally. Ownership converts a goodwill payment into an income stream an order of magnitude larger, and it transfers the risk that comes with it. Which brings us to north Devon.

> **Case study: Derril Water — when ownership meets an unready network**
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> Derril Water is Britain's biggest community solar project: nearly 10,000 co-operative members, funded by £20 million raised from members and a £22 million long-term bank loan. Its route to operation was not smooth. The original developer, Ripple Energy, had hoped the park would generate from 2024 and become a blueprint for consumer-owned solar internationally; construction delays and rising costs took the company into administration in early 2025, before the park had started operating. It was bought out by 1st Energy, and generation began in September 2025 under a volunteer board (Ambrose 2026).
>
> In June 2026, weeks before record European temperatures produced power-supply warnings, the National Energy System Operator required a super grid transformer in north Devon to be switched off, and National Grid curtailed generation in the area, to prevent the volume of rooftop solar from driving transmission-network voltage beyond safe limits — the same class of overvoltage problem that brought down the Iberian grid in April 2025 (Section 4), here contained by disconnecting the generator rather than by losing the system. Derril Water was ordered to shut for the duration of its first summer. The board described an order enforced with no warning, at a time that could not have been worse. The estimated cost is £2 million in lost revenue before restart in September; the co-operative expects neither compensation nor insurance recovery. The network problem was reportedly known since 2023, with equipment due by the end of 2025 and now delayed to September 2026 (Ambrose 2026).
>
> Three project management observations follow.

> **Interface risk was owned by nobody.** The generation project and the network-reinforcement project were separate programmes with separate sponsors, separate schedules and no shared risk register. The generation project completed; the reinforcement project slipped.
>
> **Risk allocation followed ownership, not capability.** Curtailment risk sat with the generator. A utility-scale developer with a portfolio absorbs a single site's summer curtailment as a variance. A single-asset co-operative with 9,500 members and a £22 million loan absorbs it as an existential event affecting member payments. The system allocated the risk to the party least able to carry it, without anyone deciding to.
>
> **The evidence base saw it coming.** The Local Power Plan evidence annex, published four months earlier, identified the risk that a significant increase in small-scale renewable generation on a weak part of the network could overload the system (GBE 2026). And it is not an isolated case: SSEN's report details thirteen stalled community generation projects totalling 14.2 MW, with grid-reinforcement costs "usually prohibitively expensive for community-scale projects" (SSEN 2025). The abstract warning became a £2 million loss in one place and a stalled pipeline in another.
>
> Derril Water is not an argument against community ownership. It is an argument that ownership without system readiness transfers risk onto the balance sheets least equipped to bear it, and that the sequencing of generation and network programmes is a benefits-realisation problem rather than a technical one.

What the Great British Energy (GBE) Local Power Plan actually does

Two early-stage grant funds — a GBE Community Fund for community energy groups, and a Partnership Fund for joint local-government and community projects — address the capacity and development-risk barriers. Exploratory loan schemes address construction finance and the purchase of shared-ownership stakes in larger commercial projects. An Expression of Interest process gives groups a low-commitment first step (GBE and DESNZ 2026).

The most consequential commitment has not happened yet: the Government will consult during 2026 on a mandatory shared-ownership offer to communities from commercial developers. Voluntary shared ownership has existed in Great Britain for a decade and produced modest uptake. Making it mandatory would move the United Kingdom toward the Danish and German models the Plan itself cites, where more than half of Danish wind and half of German solar is at least partially citizen-owned. It would also be a significant intervention in the commercial development market, and it will be contested.

The islands that got there first

The Local Power Plan did not invent this model; it nationalised one found on a remote Scottish island. Community Power Outer Hebrides has returned £20 million in revenues to its constituent communities over the past decade, and the Plan cites the Outer Hebrides experience as part of its inspiration (Comhairle nan Eilean Siar 2026): island practice, developed over years in one of the most peripheral parts of the United Kingdom, becoming national policy.

In the current phase, Eilean Siar Energy, a joint venture between the Stornoway Trust and Comhairle nan Eilean Siar, holds shared-ownership offers for the Stornoway and Uisenis wind farms totalling 80 MW — a community acquiring a stake in existing operating assets, with development risk already retired. For communities without the capacity to develop from scratch, which is most of them, that is a more replicable model than the heroic community-development (with huge risk) story. The Comhairle's own account records decades of energy policy and regulation developed to favour generation around urban centres, which passively disadvantaged the islands regardless of their renewable resource (Comhairle nan Eilean Siar 2026) — a reminder that there are substantial distributional consequences from technical rules, even when unintentional in their design. The islands are also developing a first-for-the-United-Kingdom Local Energy Market, allowing peer-to-peer trading between island generators and local consumers.

6. Reducing risk – ensuring the customer exists first

An energy transition is a manufacturing problem before it is a generation problem, and the United Kingdom has spent several years discovering how hard that is.

The cautionary example is Northvolt. Europe's flagship attempt to build an indigenous battery-cell manufacturer, backed by substantial capital and considerable political goodwill, entered insolvency proceedings across 2024 and 2025. The strategic ambition was sound; the commercial model — build capacity at scale and secure the offtake as you go — proved fragile when production ramp-up ran behind schedule and prospective customers went and signed contracts with alternative suppliers (IES 2025; Northvolt 2025).

AESC has manufactured battery cells in Sunderland since 2012, initially as Nissan's battery division and subsequently as an independent partner, supplying the first-generation Nissan LEAF from a plant of modest scale (AESC 2022). In mid-December 2025 the company began production at its second Sunderland plant, with an initial annual capacity of 15.8 GWh — revised up from the 9 GWh announced in 2021 — housing what AESC describes as the United Kingdom's largest cleanroom, and expected to employ around a thousand people when fully operational (Electrive 2025).

The sequencing what's important about this. Production at the battery plant already had a customer – the third-generation Nissan LEAF, which started rolling off a transformed production line at the car plant next door at the same time as battery production at the larger plant began. Nissan had invested £450 million over three years (Nissan 2025). The gigafactory was not built in the hope that demand would arrive; it was built beside its anchor customer, with the offtake contracted and the geography removing a large share of the logistics cost and carbon that attaches to importing cells. The high United Kingdom content of the vehicle, batteries included, is also what qualifies the new LEAF for the top tier of the Electric Car Grant at £3,750, linking manufacturing location directly to consumer incentive; and AESC helped launch a National Battery Academy with New College Durham and Newcastle University, addressing the workforce constraint this series identified in Article 6 (Minney 2025).

Northvolt and AESC are not a European failure and a Japanese success. They are two risk structures. One carried market risk and construction risk simultaneously; the other retired market risk before accepting construction risk. Industrial-strategy documents routinely specify the ambition without specifying that sequence. The same applies to the community solar farm at Derril water, of course.

On ethical sourcing, this article makes a project-risk observation and leaves the corporate-responsibility argument to Article 14. Battery and renewable supply chains run through jurisdictions and practices — cobalt extraction foremost among them — where labour conditions are a material delivery and reputational risk as well as a moral one. AESC, like its peers, publishes a modern-slavery statement. We'll address this later.

7. Closing well: the hierarchy we should have started with

Every generating asset ends. This series has argued from the beginning that the treatment of endings is the most reliable indicator of whether an organisation's sustainability commitments are real, and energy provides the clearest test available. There is a hierarchy, and it runs: extend, repower, recycle, remove.

Extend

The cheapest decommissioning is the one deferred by good design and good maintenance. It is worth being honest that this discipline is usually retrofitted rather than planned: leading-edge protection for windmills grew as a business precisely because the first generations of wind farms were built without it and then needed their blades saved. A blade tip can reach speeds of up to 330 km/h, exposing the leading edge to rain, hail and particulate erosion; the damage that follows is described by specialists in the field as the single largest maintenance problem in the wind industry. Applied proactively, before damage occurs, leading-edge protection extends blade life and increases annual energy production (GEV 2021).

For a project audience the point is that operations-and-maintenance strategy is not separable from closure planning: every year of additional asset life is a year of deferred decommissioning cost and deferred material demand for the replacement. The work is unglamorous — taking down 100-metre turbine blades and transporting them on narrow roads, taking down and relining blades and putting them back up on site, or perhaps even rope-access technicians applying protection on site, all of which is done in weather, trained through campaigns run near the company's East Yorkshire base — and the specialist capability is itself a British export serving Europe, North America and Australia.

Repower

In November 2025, ScottishPower completed the repowering of Hagshaw Hill, and it is close to a perfect case study for this series (BBC 2025; Hill 2025; ScottishPowerRenewables N.D.). Hagshaw Hill was Scotland's first commercial wind farm, commissioned in 1995 near Douglas in South Lanarkshire with twenty-six turbines totalling 16 MW, with a further twenty added in 2008. Having reached the end of their design life after thirty years, the twenty-six original turbines were dismantled and replaced with fourteen new machines with a nameplate capacity of 79 MW[3] — five times the capacity from roughly half the number of turbines, on the same site, with the grid connection and the access roads already in place. That is what generational replacement looks like when it is planned rather than improvised, and a direct answer to the objection that renewable energy consumes land indefinitely.

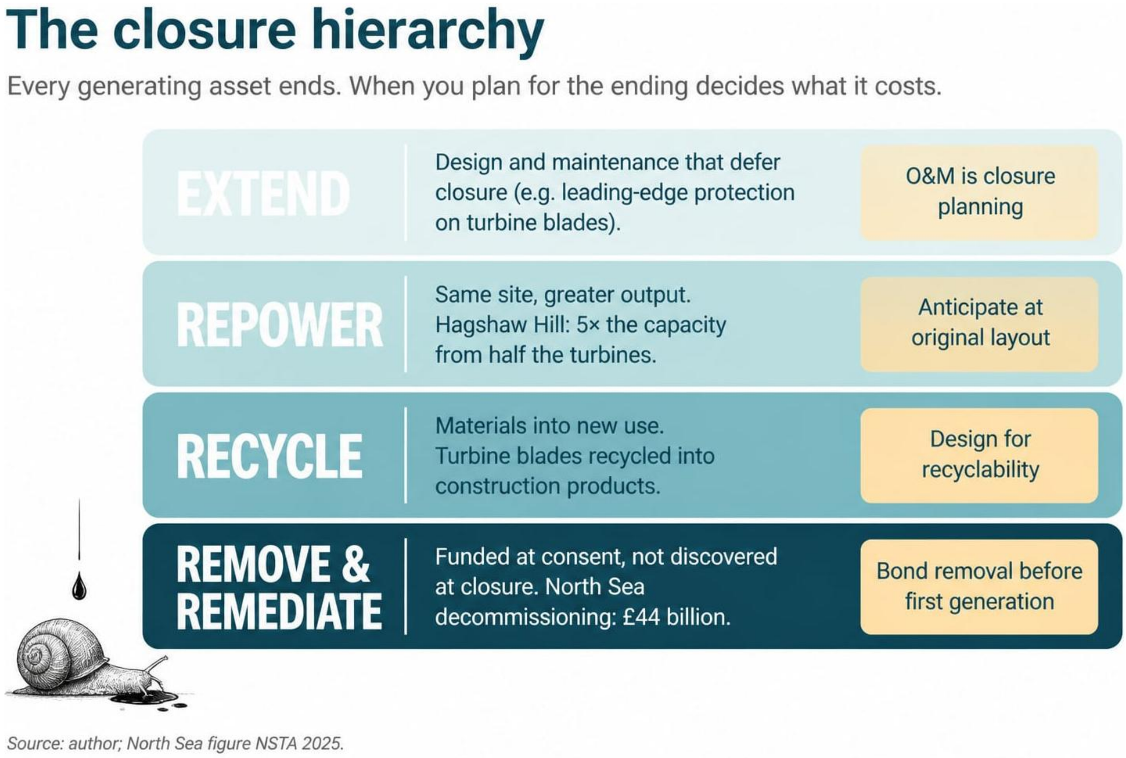

Figure 3 The closure hierarchy: extend, repower, recycle, remove. Each rung is a decision cheaper to take at consent than to discover at closure — as the half-poisoned snail in the corner attests.

The community dimension connects this section back to Section 5. The community benefit fund was repowered alongside the turbines: it now delivers nearly £400,000 a year to Coalburn, Douglas, Lesmahagow, and Rigside and Douglas Water — approximately twenty-six times the

[3] The proposal was for 84 MW, i.e. with a community benefit payment of £5,000 per MW per year, this would contribute £420,000, but the installed capacity is 79 MW with the same community benefit payment per MW.

original fund (per year) — over a horizon of around twenty-five years. A community that hosted the first generation of Scottish wind is materially better off from hosting the second, by an order of magnitude, and benefit realisation here has an asset-generation cadence measured in decades, a longer view than most benefits regimes are built to take.

Recycle

Disposal of turbine blades have been the most persistent material objection to wind energy: composite structures are difficult to recycle and have historically gone to landfill or incineration. At Hagshaw Hill, every blade from the original turbines was recycled by the Irish manufacturer Plaswire into construction materials replacing timber and plastics, diverting the waste from incineration and displacing higher-carbon products (Hill 2025). One project does not settle a global materials question, but it moves blade recycling from the category of unsolved to the category of solved-but-not-yet-standard, which changes how the objection should be treated in planning inquiries and public debate.

Remove and remediate — funded at consent

Which brings us to the North Sea, and the most expensive lesson in the British energy estate. The North Sea Transition Authority's July 2025 assessment puts the remaining cost of decommissioning United Kingdom Continental Shelf oil and gas infrastructure at £44 billion in 2024 constant prices, with well plugging and abandonment about half of that total; some £27 billion of it falls within the decade from 2023 to 2032, and operators spent a record £2.4 billion in 2024 alone (NSTA 2025a, 2025b).

The trend is the wrong way. The estimate rose by £3 billion year on year, driven by inflation, higher rig day-rates, work brought forward without time to optimise, and activities exceeding planners' initial estimates — against a background in which the regulator had already re-baselined the estimate to £37 billion in 2022 with a target of a further 10% reduction by the end of 2028 (NSTA 2025b).

In December 2025 the NSTA published a table naming thirteen operators that had missed consent deadlines for decommissioning 153 inactive wells, alongside nine licensees operating 780 wells who were in compliance; nearly a thousand inactive wells will ultimately require full decommissioning. Its warning was blunt: delay drives up cost, reduces rig availability as contractors move to other basins, and pushes billions onto companies and — through decommissioning tax relief — onto taxpayers (NSTA 2025c). Whatever any individual operator intends, that tax treatment socialises a large part of the bill regardless of intent, which is why the regulator is now naming names and why some argue the accountability should reach individual directors rather than stop at the corporate entity. Naming and enforcement are the tools available to head off delay becoming default.

Article 7 in this series set out a critique of what happens when the end of an industrial activity is not planned: dig, dump, destroy, desert (Minney 2026a). The North Sea backlog is that critique arriving as a regulator's enforcement table, with named companies and counted wells — the most tangible demonstration available that closure deferred is closure made more expensive, and the deferral might ultimately be socialised through abrogation (bankruptcy).

There's a positive side to all this. The same programme represents roughly £21 billion of work for the United Kingdom supply chain over the next decade, under a North Sea Transition Deal commitment that at least half of decommissioning expenditure goes to domestic suppliers (NSTA 2025b). But decommissioning and offshore wind draw on the same heavy-lift vessels and much of the same skilled offshore workforce, and offshore wind's long installation campaigns are more attractive to vessel operators than short, technically awkward oil and gas rig decommissioning jobs. Offshore Energies UK has warned that this competition for tonnage and people could create bottlenecks in both directions (OEUK 2022, 2023). A decommissioning surge and a wind build-out competing for the same constrained resource is a scheduling risk the sector has not fully answered, and it belongs on the risk register of both.

Nuclear decommissioning includes liabilities measured in centuries; this series examined the Vandellòs experience and the aftermath of station closure in Article 6 and does not repeat it here. The principle that unites the hierarchy is simple to state and evidently hard to practise: decommissioning should be designed and funded at the point of consent, not discovered at the point of closure. Leading-edge protection specified at procurement, repowering anticipated in the original site layout and grid connection, blade recyclability considered at material selection, removal bonded before first generation — each decision can be taken early and cheaply, or late and expensively.

8. Conclusion: the Five Ps of a regenerative energy system

This series uses the Five Ps — People, Planet, Prosperity, Peace and Partnership — as its organising framework. Energy generation and distribution touches all five, and one of them more sharply than any previous article in this series.

People. The ownership structure changes outcomes measurably: more local expenditure, more local employment in construction and operation, higher local acceptance mediated by perceived fairness, and — in the Devon modelling — £15.9 million of additional local economic value from a 30 MW solar farm, enough to outweigh a £2–4 million cost premium (itself an artifact of modelling) several times over. Ownership structure is a benefits lever, and using it is a decision only available during early development. By financial close it has been decided.

Planet. How we decommission is where the transition's environmental integrity is tested. Repowering at Hagshaw Hill produced five times the output from the same land with half the turbines and full blade recycling; the North Sea backlog shows what the alternative costs. The technology wasn't there for recycling when each was built, but the people involved with the renewables project were more determined to find a solution.

Prosperity. The supply chain has to exist before the assets can. AESC's Sunderland sequencing — anchor customer first, capacity second — is the model that worked where Northvolt's did not. Decommissioning is £21 billion of United Kingdom supply-chain work over a decade if it is managed as an industry rather than a liability, though it competes with offshore wind for the same vessels and people. And the £2 billion a year of system-cost reduction attributed to Sizewell C arises largely in network, interconnector and balancing costs — somebody else's budget — a second-remove benefit that requires a properly scoped appraisal.

Peace. This is where Article 11 (this article in the sustainability series) differs from its predecessors. Energy is the domain in which sustainability and security are the same subject. Ofgem cites exposure to wholesale gas prices, and the geopolitics that drive them, as a principal reason for the urgency of connections reform (Prestley-Abbott 2026). The Sizewell C assessment lists among its un-monetised benefits the mitigation of extended wind-and-solar droughts, interrupted energy imports, and national-security threats to offshore and subsea infrastructure (DESNZ 2025b) — the same tail risks whose correlation, as Section 2 noted, the assessment does not model, even though a climate-stressed world delivers them together. Great British Energy's founding rationale is framed around reducing dependence on imported fuel and on the price shocks that dependence transmits into every household.

A distributed, community-owned, domestically manufactured energy system is a fairer system and a cleaner one. It is also a harder system to coerce by an external malevolent actor. National resilience belongs in the business case as squarely as the carbon numbers do. Project managers working in energy are working, whether or not it appears in their terms of reference, on the security infrastructure of the country.

Partnership. The failures in this article are almost all coordination failures. Derril Water is a coordination failure between a generation programme and a network-reinforcement programme. The Iberian blackout is a coordination failure in voltage-regulation practice, in the specification of generator behaviour, and in data visibility between transmission and distribution. The North Sea backlog is a coordination failure between operators, supply chain and regulator over decades. The connections queue is a coordination failure that Ofgem and NESO are now, belatedly and creditably, addressing. Partnership in this domain is the difference between a system that works and one that fails at 12:33 on a Monday afternoon.

What project managers should do

The actions listed are based on the examples in this article, but all of the advice applies to projects outside of energy:

- *Specify system services, not just energy.* A generation project that produces electricity but does not contribute to voltage control, reactive power or system stability has been scoped too narrowly. A repeat of the Iberian peninsula blackout is what poor scoping produces at scale, and these capabilities are cheap at design and expensive at retrofit.
- *Treat the grid connection as a programme interface, not a procurement item.* Where a project's viability depends on network reinforcement delivered by another organisation, that dependency belongs on the risk register with a named owner, a monitored schedule,

and an agreed position on who carries curtailment risk if the reinforcement is late. Derril Water's members are paying £2 million for the absence of that conversation.

- *Decide ownership structure while it is still decidable.* Shared and community ownership deliver measurably greater local benefit, and the option closes early. If the mandatory shared-ownership consultation proceeds, developers who have thought about it in advance will be better placed than those who have not.
- *Fund and design closure at consent.* Extension, repowering, recyclability and removal are all cheaper as design decisions than as end-of-life discoveries. The regulator now publishes the names of the organisations that got this wrong.
- *Assure the supply chain with the rigour applied to the engineering.* A modern-slavery statement that has not been tested is a document, not a control.

The energy transition will be delivered by projects. Whether it is delivered as a regeneration — leaving communities, supply chains and landscapes measurably better than it found them — depends on decisions made in the first quarter of the project life cycle that cannot be retrofitted in the last quarter. That has been the argument of this series throughout. Nowhere is it more visible, or more expensive to ignore, than here.

AI usage in researching and writing this paper – statement by the author

This article, "Energy generation and distribution: powering a regenerative future", was prepared with the assistance of an Artificial Intelligence (AI) large language model (LLM). Under direction and control of the author, the AI LLM was used to facilitate the drafting, research, and refinement process of the article. For example, AI was guided to refine the language to ensure it aligned with British English conventions, maintained a professional yet accessible tone, and avoided common AI-generated phrasing. An AI tool was also used to assist in the generation of illustrations. The author maintained full control at all times and assumes full responsibility for the completed work.

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Dr. Hugo Minney is a Fellow of APM (Association for Project Management), a Member of PMI and PMI UK, Lead of APM's Benefits and Value IN (Interest Network) and Sustainability IN, founder of APM's Nuclear Industries IN and AI & Data Analytics IN, and committee member of PMI UK's Sustainability Community of Action (none of which are paid). Minney is also chair of the British Standards Institute's working group on Benefits Management, which publishes and maintains BS 202002 (Applying benefits management on portfolios, programmes and projects) (also unpaid).

Minney is a business consultant. He analyses the benefits of change, and weighs them up against the need for effective operations to keep the lights on; he has built business cases of all types and is acutely aware of the pressures to make a single project a success at the expense of the organisation's objectives and the need to resist this; as a former executive board director in National Health Service he can take a portfolio overview and prioritise the individual benefits of projects to ensure the success of the whole organisation. Minney is now a project management consultant with a sideline chairing a charity restoring the sense of community for young people.

Minney specialises in putting a number on difficult benefits (such as sustainability and regeneration), motivating team members by reporting what they are achieving together and motivating teams to build the communities and companies we want to be part of – together. He believes in standards and is accredited as a Social Value practitioner and Chartered Project Professional.

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