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Grid topology and the spatial cost of AI data-centre siting

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Abstract

The rapid growth of AI data centers is straining power grids. Yet whether siting costs are driven by short-run electricity prices or network topology remains unclear. Here, we address this by comparing two distinct 2030 power systems, New Zealand's radial grid and Ireland's meshed ring. Testing identical loads across hundreds of scenarios varied by gas and carbon prices, demand, weather and transmission capacity, we find network topology dominates siting costs. New Zealand splits into two cost zones across the Cook Strait link, where the 4.18% gap matches the one-way converter loss exactly and vanishes when that loss is removed. In contrast, Ireland stays a single cost group under routine operation with variations below 0.1%. Our results demonstrate that price signals effectively guide data center siting primarily where the network is bottlenecked. In highly meshed grids, physical grid reinforcement becomes essential.

Introduction

The decarbonisation of electrical networks coincides with the rapid, energy-intensive growth of artificial intelligence demand [1,2]. This growth creates a direct conflict: clean-energy transitions require supply-side operational flexibility, whereas computational clusters impose large, inelastic load increments. Individual AI training clusters already draw hundreds of megawatts, with the largest announced sites approaching a gigawatt [3], and, unlike traditional large loads tied to a fixed resource such as a smelter to hydro power, they are footloose: they can connect almost anywhere with adequate power and fibre connectivity [4]. Driven by continuous availability guarantees, they also integrate into power systems as rigid, non-dispatchable point loads [5], so where such a footloose, gigawatt-scale, inflexible load lands is now a live economic decision rather than a fixed geographic given. Concentrating large, anticipated demand at single nodes reshapes where the long-run system costs of integration fall and leaves them poorly quantified [5,6].

Two competing accounts govern spatial siting costs. The parametric view holds that siting costs are set by volatile operating variables comprising wholesale prices, fuel costs, carbon charges, and regional tariffs; adjusting these parameters supposedly steers infrastructure layout [7,8]. The topological view holds that spatial cost is pinned by network physics including line impedances, transfer capacities, and generation-load geometry; the cost surface is encoded in the wires, remaining insensitive to short-run parameter shifts [9]. These accounts imply opposite interventions, market reform versus physical reinforcement, yet prior work fails to isolate them [10,11].

The academic literature addresses four distinct but partial problems. Operational studies treat existing facility locations as fixed, shifting workloads via locational marginal price or carbon signals, thereby failing to capture long-run capacity expansion costs [12,13]. Distribution-level studies optimize placement on synthetic test feeders like the IEEE 33-bus or 69-bus systems, producing localized profiles that do not transfer to real transmission grids with inter-regional constraints and heterogeneous renewables [14,15].

Joint planning studies co-optimize location and grid expansion in large interconnected markets but aggregate data at zonal resolutions, rendering nodal cost signals, line flows, and bus-level marginal costs invisible by construction [16]. Demand forecasting studies predict geographical load concentrations based on regional capacity denominators but omit intra-network topology constraints, revealing where demand clusters but not where it should connect to minimise system costs [17]. Across these four strands, no study has injected a firm constant load at every candidate node of a calibrated national network, recorded the resulting system cost, and perturbed operating parameters to test whether the spatial cost pattern shifts or holds. That experiment is the missing step needed to determine whether siting cost is set by network physics or dispatch parameters.

We resolve this indeterminacy through a controlled cross-country experiment, leveraging the contrasting network geometries of New Zealand and Ireland to separate topological structure from parametric variation. Into each system, we inject a firm point load at every candidate node of each network, eight in New Zealand and five in Ireland, each set chosen to span its grid's structural extremes, across three capacity dimensions (100, 300, and 500 MW), solving the full network optimal power flow in the open-source PyPSA-Earth model across the resulting suite of runs. Methodologically, our comparison of New Zealand and Ireland isolates the effect of network topology on the cost of integrating concentrated hyper-scale computing load. The two countries share the baseline characteristics a siting comparison must hold fixed: similar populations, Ireland 5.4 [18] and New Zealand 5.3 million [19], comparable national electricity demand, and a high renewable share. In both, combined-cycle gas typically sets the marginal price, which offsets the difference between New Zealand’s hydro and geothermal fleet and Ireland’s wind-dominated one, so the principal structural divergence that remains is the geometry of the network itself: a bottlenecked inter-island corridor in New Zealand against a meshed ring in Ireland.

Both are policy-relevant test cases for digital infrastructure. Ireland is the first advanced economy where data-centre power consumption has passed 20% of total supply, triggering administrative connection moratoria [20]. New Zealand, by contrast, is a target site for low-carbon AI computing [21], where technology firms target high-renewable grid baselines to meet corporate net-zero mandates. This commercial geography is reflected in hyperscale cloud and AI infrastructure investments now under construction or recently commissioned in Auckland and its surroundings [21,22]. This green-computing demand is spatially decoupled from supply: operators site facilities near northern demand hubs while the highest-yield renewable resources sit in the southern hydro-basins [23].

To ensure cross-comparability, the Irish baseline is islanded, with all cross-border interconnectors removed, so that both systems are genuinely electrically isolated and any divergence in spatial cost is attributable to internal topology alone. We verify robustness by reintroducing interconnectors and by testing at a coarse 8-bus resolution.

Our experiment reveals qualitatively opposite spatial structures: New Zealand separates into two equivalence classes fixed by the Cook Strait converter loss, whereas Ireland collapses to a single class that survives every parameter perturbation. Together they establish a principle we term Parametric

Invariance: within a fixed network, topology rather than short-run dispatch sets the spatial cost surface. While the mechanism applies to any firm, inflexible load, hyper-scale AI training clusters are its most urgent contemporary instance.

Results

2.1 Two matched baselines with a common marginal price-setter

Both national systems are renewable-rich, yet in each the marginal price of electricity is set by the same dispatchable technology, combined-cycle gas (CCGT). We term this configuration the flexibility trap: variable renewables supply the bulk of energy but cannot set the marginal price, so the short-run cost of serving an additional firm megawatt is anchored to the single dispatchable technology that provides residual balancing. Gas occupies the margin in about 59% of dispatch intervals in Ireland and in 99.97% in New Zealand (Table 1), a shared feature that makes their divergent siting outcomes a substantive result rather than an artefact of different fuel mixes.

In the New Zealand baseline (~ 92% renewable; Table 1), CCGT sets the marginal price in almost every dispatch interval (99.97%) despite supplying only a small share of energy. Even in the hydro-dominated South Island, where stored water is physically at the margin, its opportunity cost tracks the North Island gas price through the Cook Strait link, so gas anchors the price level across both islands. The short-run value of an incremental firm megawatt is therefore governed by the gas cost, not by the water value or the wind-curtailment cost.

The Irish baseline (~ 71% renewable; Table 1) reproduces this structure. With coal, peat and oil retired, a carbon price of ~ 95 EUR/t lifts CCGT to the top of the merit order, where it sets the price in about 59% intervals. Only at rare hours of low wind and high demand does the islanded system shed load, and then only marginally (0.018% of annual demand). The two systems nonetheless differ roughly threefold in absolute cost, higher in Ireland than in New Zealand (Table 1), a gap driven chiefly by fuel: carbon-taxed gas against near-zero-fuel-cost hydro. Whether renewables supply seven- or nine-tenths of energy, the same flexibility trap holds.

This shared margin is the experimental control. Because the price-setting technology is common to both systems and their renewable shares are comparably high, any difference in how the cost of a new data centre varies across candidate locations cannot be attributed to a different marginal fuel or a different degree of decarbonisation. The opposite spatial outcomes reported below must therefore originate in the only dimension that separates the two systems: the geometry of the network itself (Fig. 1).

Table 1
Matched baselines: New Zealand and Ireland under official 2030 scenarios.

Parameter	New Zealand	Ireland
Spatial resolution	55-bus	26-bus
Annual demand (TWh)	48.15	44.50
Peak demand (GW)	7.20	6.80
Renewable share (%)	91.95	71.40
Marginal technology	CCGT	CCGT
Marginal cost (EUR/MWh)	74.96	115.8
Annual system cost (M EUR)	589.3	1,611
Inter-island link	HVDC	None (AC ring)
Candidate nodes	8	5
Load shed	0	7.90 GWh (0.018%)

2.2 Opposite equivalence-class structures under an identical injection

We inject an identical firm point load at every candidate node of each calibrated network and record the resulting change in system cost. The injection is a comparable macro-shock in both systems, spanning roughly 1 to 7% of national peak demand in New Zealand and 1.5 to 7% in Ireland across the 100 to 500 MW range. The same experimental treatment produces qualitatively opposite spatial structures in the two countries (Fig. 2).

In New Zealand, the eight candidate nodes separate into exactly two equivalence classes that map cleanly onto the country's two islands. At a 100 MW injection, South Island nodes carry a siting cost of 71.96 EUR/MWh and North Island nodes 74.96 EUR/MWh, equivalent to 119.26 and 124.24 NZD/MWh, a cost advantage of 4.18% for the south that widens modestly with injection size, from 4.18% at 100 MW to 4.95% at 500 MW, with the cost at every candidate bus reported in Supplementary Table 2. The cost surface is binary: every node belongs to one of two price plateaus, and the plateau boundary, mapped in Fig. 2a, coincides with the geographical division between the islands.

In Ireland, the identical injection collapses to a single equivalence class. Because the islanded 2030 system sheds a small quantity of load at peak hours, the marginal siting cost at each node carries a spatially uniform scarcity rent equal to the energy not served multiplied by the value of lost load; we remove this common term and classify on the generation-cost component that remains. Across the five county candidate nodes of the 26-bus network, the generation-cost component of the siting cost of a

100 MW load averages 75.84 EUR/MWh, equivalent to 664,381 EUR/MW/yr, and ranges from 664,309 to 664,412 EUR/MW/yr, a generation-cost spread of 0.016%, reported county by county in Supplementary Table 3; the raw spread including the spatially uniform scarcity rent is smaller still at 0.007%. Both lie one to two orders of magnitude below the 1% equivalence threshold, and the more conservative generation-cost figure is the one we report. No subset of nodes forms a distinct price plateau; the cost of siting a hyper-scale load is, to within discretisation noise, the same wherever in the country it connects. The same physical experiment that exposes a sharp, geographically aligned two-class structure in New Zealand, set beside the Irish result in Fig. 2, reveals no spatial structure at all in Ireland.

2.3 Origin of the New Zealand inter-island cost gap

The New Zealand two-class structure is not merely correlated with the island boundary. It is caused by it. The only inter-island connection is the Cook Strait HVDC link, rated at 1,400 MW with a one-way converter efficiency of $\eta = 0.96$ (sourced from Transpower's published full-load converter losses; we sweep η across its full 0.90–1.00 range, so the finding rests on the converter loss itself rather than on this particular value). We show below that the class gap equals the converter loss exactly, tracks it when the loss is varied, and survives every change to the South Island generation fleet (Fig. 3).

The mechanism is straightforward. South Island reservoirs value their stored water at the North Island gas price, discounted by the one-way link loss:

$$P_{South} = P_{North} \times \eta = 74.96 \times 0.96 = 71.96 \text{ EUR/MWh}$$

The resulting price ratio matches $1/\eta$ to four decimal places (1.0417), and the 4.18% siting-cost premium reproduces the analytic loss $(1 - \eta)/\eta = 4.17\%$ to within 0.01 percentage points. That residual is not a hidden network loss, the model carries no other loss besides the converter, but the ordinary noise of averaging locational prices over a full dispatch year. In short, the cost of crossing the class boundary is the cost of pushing a megawatt through the converter, to four significant figures.

We confirm this causally in three ways. First, we sweep the converter efficiency itself. Across seven steps from $\eta = 0.90$ to 1.00, the North Island cost barely moves, under 0.01%, while the South Island cost climbs steadily as the link is made progressively lossless. The premium tracks $(1 - \eta)/\eta$ at every step (Supplementary Table 4: 11.13% vs 11.11% at $\eta = 0.90$; 4.18% vs 4.17% at the baseline; 1.02% vs 1.01% at $\eta = 0.99$), and collapses to the solver's precision floor, 0.013%, when the link is made lossless. The two classes merge exactly when the loss they track disappears.

Second, we test whether South Island generation itself, rather than the link, could explain the gap. It cannot. Adding up to 2,000 MW of same-cost South Island gas leaves the premium fixed at 4.18%, because South Island hydro already meets local demand and exports the surplus north; the added plant simply never dispatches. Halving South Island hydro capacity instead leaves the same result. Neither direction moves the number.

Third, we let the network itself respond. Allowing every alternating-current line and the Cook Strait interconnector to expand at zero capital cost still leaves the premium at 4.18%. This rules out congestion as the source: a congestion rent would be relieved by free transmission investment, a conversion loss would not.

Together, these three tests point to a single conclusion: the New Zealand siting signal is set by one physical constraint, the HVDC converter, and nothing about the generation fleet can substitute for it. The Irish control (Section 2.4) completes the argument, a gas-marginal system with no inter-island HVDC produces no second class at all, which rules out the alternative that any system caught in the flexibility trap will show a 4% gap regardless of topology.

2.4 Robustness of the Irish single class to perturbations

If the New Zealand result shows a topological signal that can be switched off, the Irish result shows the same physics in its complementary form: a topology that admits no signal to begin with, and that no parametric perturbation can induce one (Fig. 4).

The single class survives every robustness dimension we impose (Fig. 4; Supplementary Discussion 2). In the 26-bus network the generation-cost spread on which we classify is 0.016%, 0.019% and 0.072% at injections of 100, 300 and 500 MW, remaining one to two orders of magnitude below the 1% equivalence threshold and single-class at every size; the raw spread including the uniform scarcity rent is smaller still, at most 0.025%. In the analytical-limit 8-bus network, where the discretisation noise of the county representation is removed, the spread falls to the linear-programming precision floor, the exact signature of an uncongested all-AC ring. Re-solving the injection across additional weather years and with the Great Britain and France interconnectors re-introduced leaves the single class intact; that reconnecting the cross-border links does not split the class rules out the islanding protocol itself as the source of the uniformity. We report the 26-bus generation-cost spread honestly as sub-threshold discretization noise rather than as a measured spatial gradient; the 8-bus figure approximates the underlying cost identity that the county network discretises.

The central parametric test follows. Across ten policy perturbations, spanning plus and minus 50% swings in gas and carbon prices, plus and minus 20% in demand, and the removal of transmission capital cost, every node remains in a single class at all three injection sizes (Fig. 4a), the widest generation-cost spread being 0.127% under a halved gas price and the surface collapsing to the linear-programming floor when transmission is made free. Under a halved gas price, the absolute marginal cost falls and the denominator of the percentage spread shrinks, mechanically widening the ratio even though the absolute cross-node cost range is unchanged; the 0.127% is a denominator effect rather than a change in the spatial cost structure. Tightening the line thermal limits across four settings preserves the single class as well, the most restrictive 0.70 per-unit limit reaching 0.297%. A gas-price or carbon-price swing large enough to reorder the thermal stack thus changes the system-wide marginal cost level but not its spatial uniformity, because there is no congested interface across which a differentiated price

could form. The Irish cost surface is flat not by coincidence of any particular fleet but by construction of the network: a compact, fully closed AC ring offers no congested interface for a price gap to form across.

A final test removes the network's freedom to expand by freezing every line at its optimized capacity and re-running the injection, which isolates whether the flat surface is a property of the topology or of the optimizer’s freedom to build transmission. At 100 MW the single class holds, with a generation-cost spread of 0.013%. At 300 MW and above it breaks (Fig. 4b): a remote midland node that generates almost nothing and depends entirely on imported power can be supplied only by forcing that power through a fixed set of thin lines, which congest and price that node far above the rest, opening generation-cost spreads of 3.54% at 300 MW and 76.01% at 500 MW and separating the country into two classes. Unlike the 2018 grid, in which such a load could not be delivered to that remote node at all, the stronger 2030 network delivers it but only at a congestion premium. This boundary case delineates when the flat surface holds: the Irish surface is flat not because location is irrelevant but because the meshed ring, together with the freedom to reinforce it, masks a latent locational cost; withdraw that freedom and load the network hard enough and the topological cost surface reappears.

2.5 Scope of the flat Irish cost surface

The mathematical flatness of the Irish cost surface should not be read as a claim that concentrating hyper-scale load carries no localized consequence for the physical network. A cost-minimising optimal power flow identifies the economically efficient dispatch; it does not certify the system against the thermal overloads, voltage excursions, or contingency events that govern real-time operation, and our single-class result therefore speaks to the spatial structure of cost alone, not to operational security.

The flatness has a precise optimisation origin. Because the baseline alternating-current ring operates below its congestion thresholds under routine optimal dispatch, the dual variables on the line-flow constraints are zero at every bus, so each node prices at the single system-wide marginal generation cost and no locational component survives. The locational marginal price is, in consequence, numb: it carries no scarcity premium to mark the buses where added demand would first erode regional adequacy, and it returns the same value at a saturated Dublin node as at an empty western one. We note, however, that the New Zealand identity is robust to this representational choice: the 4% gap is fixed by the HVDC converter loss, which is the one loss the lossless-AC formulation explicitly retains. Because our headline results treat the alternating-current network as lossless, we test that assumption directly in a dedicated loss suite (Supplementary Fig. 5, Supplementary Table 5, Supplementary Method 4): for Ireland, adding physical alternating-current losses leaves the single class essentially intact, introducing a smooth, distance-ordered premium of about 2%, an order of magnitude below New Zealand's inter-island step under the same loss representation (Ireland 2.19% against New Zealand 24.03%; Supplementary Table 5), and without any comparable threshold.

Discussion

Our experiment resolves a question single-system studies leave entangled: whether the spatial cost of siting a large inelastic load is set by dispatch parameters or by network geometry. The answer is a principle we term Parametric Invariance: within a fixed transmission network, the spatial structure of siting cost is set by topology and is insensitive to short-run dispatch parameters, whether wholesale prices, fuel and carbon costs, weather year, or cross-border interconnection. New Zealand and Ireland sit at its two extremes, a bottlenecked corridor against a closed meshed ring, so it is demonstrated at its end-members rather than across the continuum between them.

By supplying the missing structural comparison, our experiment provides direct evidence. New Zealand and Ireland now draw comparably high shares of their energy from renewables, nine-tenths and roughly seven-tenths respectively, yet the same combined-cycle gas technology sets the marginal price in both under a shared flexibility trap. Renewable penetration, marginal technology, and system scale are all closely matched. The contrasting spatial outcomes are therefore unlikely to originate in generation economics. The matched fuel mix removes the leading alternative explanation. The cause is left to the one dimension that genuinely differs: the geometry of the network itself.

The two systems expose this from opposite directions. In New Zealand, exchange funnels through one corridor, the Cook Strait HVDC link, and the 4.18% gap is exactly its converter loss (Section 2.3): the signal lives in the corridor. In Ireland the closed AC ring offers no such interface. Under routine optimal dispatch it does not congest, its line-flow constraints carry no shadow price, and every node prices at one system-wide marginal cost, so the locational signal is numb (Section 2.5). The small quantity of load shed at peak hours enters as a spatially uniform value-of-lost-load rent that lifts every node equally, and once decomposed away the generation-cost surface remains flat. In the terms the model permits, a lossless network can open a spatial price gap only across an interface that either carries a loss or binds against its capacity, and New Zealand has exactly one such interface where Ireland has none. Transmission losses sharpen rather than create this boundary: adding AC losses induces a fine price gradient within the North Island while the hydro-rich South Island stays homogeneous (Supplementary Discussion 5).

This unresponsiveness is not incidental; it is a market-design failure imposed by the topology. When routine network states absorb the price signal, no locational charge can mark the buses where added demand would first erode regional adequacy, and capital concentrates wherever non-electricity factors favour until the host network is physically exhausted. Yet the flat surface is a property of topology together with the freedom to expand it, not an absence of geography: when network expansion is withdrawn and the injection scaled up, the single class breaks and a congestion premium reappears at the remote nodes the meshed ring had masked (Section 2.4). Ireland's connection moratorium is the visible consequence: with the price lever inert, the system operator was left with the blunt instrument of administrative refusal, a price signal nullified by the geometry it was meant to value. Where concentrated load growth outpaces transmission investment, the topological cost surface re-emerges even in a fully meshed AC network.

A clarification on whose cost we measure. The siting cost we report is the system marginal cost, the locational signal an efficient market would pass to a user to indicate where an additional firm load is cheapest to serve. It is not the retail tariff an operator pays, which layers network charges, taxes and regulated margins on top. This distinction sharpens rather than weakens the result. Where the system carries a locational signal, as across the Cook Strait interface, it can in principle be passed through to locational charges and steer siting on genuine cost grounds. Where it does not, as in the Irish ring, there is no efficient signal for any tariff design to transmit. The geographic variation a user still sees in that case reflects network-recovery and regulatory artefacts, not the system cost of siting. The numbness we identify is a property of the locational signal itself, and no pricing instrument downstream of it can restore what the topology has erased.

A diagnosis comes before a prescription. The same demand shock calls for opposite instruments depending on the network it meets. Where exchange is bottlenecked, as in New Zealand, the siting signal already exists and needs only to be exposed; transmission-aware pricing that passes the corridor loss through to locational charges can steer hyper-scale demand toward the cheaper region without any administrative bar. Where exchange runs over a meshed ring, as in Ireland, no price instrument can differentiate locations however it is tuned, and the lever shifts to physical reinforcement or explicit zoning. For the many jurisdictions now siting concentrated artificial-intelligence load, from the United States to continental Europe to China, where planning areas often span both heavily meshed and bottlenecked topologies, the first step is therefore to classify the network before choosing an instrument, since a market remedy that is efficient in a bottlenecked system is inert in a meshed one. Whether a deliberately constrained interface could be engineered to manufacture a steerable signal where none exists is a question our static experiment raises but does not settle. This contrast is already embodied in market design: New Zealand operates a nodal wholesale market that prices roughly 285 grid injection and exit points separately [24], whereas Ireland's all-island Single Electricity Market clears at one uniform price [25], the two designs mirroring the two-class and single-class verdicts the experiment returns.

Several boundaries delimit these conclusions. Our linearised DC optimal power flow represents thermal line limits but not the full AC security problem. It carries no AC losses and treats the Irish ring as a lossless transport network without reactance, so part of the Irish flatness is representational rather than purely topological. We state this as a bound rather than a claim (Supplementary Discussion 4), and it leaves the New Zealand identity untouched, since that gap is fixed by the one loss the model does carry. We leave N-1 contingency screening and voltage and reactive-power profiles to future work because annual security-constrained dispatch scales poorly across many nodes and thousands of time steps; the 2030 fleet is held fixed without capacity expansion; and storage and demand response are omitted, each of which could introduce the inter-temporal coupling our static treatment sets aside. None reaches the core finding, because the spatial cost structure depends on the identity of the marginal supplier, stable across every perturbation. Extending the experiment to security-constrained dispatch, storage-rich systems, and networks between the two topological extremes would test how far Parametric Invariance travels.

Methods

Modelling framework

Both national systems are represented in PyPSA-Earth [26] and solved as a linear direct-current optimal power flow that minimizes total annual operating cost subject to nodal energy balance, generator capacity and ramp limits, storage continuity, and thermal line-flow limits, with the full mathematical formulation set out in Supplementary Method 1. The alternating-current network is modelled as a lossless linear transport of active power, so that the only network loss in either system is the Cook Strait converter in New Zealand; Ireland's network carries no conversion loss. Each year is solved at three-hour resolution, giving 2,920 time steps that span the full 8,760 hours. In Ireland the generation fleet is held fixed at the configuration of the country's official 2030 decarbonisation scenario, the fleet delivered by the EirGrid Generation Capacity Statement and Climate Action Plan, so the problem is one of pure economic dispatch; in New Zealand the thermal and hydro fleet is fixed while variable renewable and open-cycle peaking capacity are co-optimised up to their scenario caps. Both systems therefore represent the same 2030 planning horizon. This expansion asymmetry does not compromise comparability, because in both systems the marginal cost of serving an injected megawatt is set by existing combined-cycle gas, so generation capital costs enter the baseline level but cancel from the marginal siting cost that we report. Ireland prices carbon through an explicit emission charge of 95.45 EUR/t, and the spatial siting result is invariant to the carbon price across the sensitivity sweep in both systems.

Network topologies

To establish rigid cross-comparability, our primary baseline enforces a strict isolation protocol, removing all cross-border import allocations from Great Britain and France so as to isolate the intrinsic pricing behaviour of the synchronous Irish ring. This islanded protocol is a deliberate controlled counterfactual: it holds the siting question fixed while matching Ireland to genuinely islanded New Zealand, so any divergence is attributable to internal topology rather than to external market ties, and its robustness against coarser resolution and against reintroducing the interconnectors is verified below, where reconnecting the Great Britain and France links leaves the single equivalence class intact, confirming that the islanding protocol is not the source of the uniformity. Geometrically, New Zealand is a fractured system split by a single high-voltage direct-current transfer constraint, whereas the baseline Irish system is a compact, fully-closed alternating-current ring, letting us evaluate whether spatial divergence is a mutable product of external market ties or an unyielding reflection of grid geometry.

The New Zealand network has 55 alternating-current buses, comprising 40 in the North Island and 15 in the South Island, connected by 87 alternating-current lines and the single Cook Strait high-voltage direct-current link; the same network is also solved at a coarser 15-bus resolution to test whether the two-class inter-island result reflects the grid itself rather than the chosen clustering, a check across which the roughly 4% gap magnitude is preserved (Supplementary Fig. 4). The link is rated at 1,400 MW northward

and 950 MW southward under the planned 2030–31 upgrade [27] with a one-way converter efficiency of η = 0.96 [28]. The Irish primary network represents the island at county scale through a 26-region clustering that yields 26 active alternating-current county buses connected by 53 lines with no direct-current element. An 8-bus aggregation of the same system, with 13 lines, serves as an analytical-limit corroborator: coarsening removes the discretisation noise of the county representation, so the residual sub-threshold spread collapses to the solver precision floor, confirming that the single class is a feature of the topology and not of the clustering. The Irish baseline is islanded, with the Great Britain and France interconnectors excluded so as to match genuinely islanded New Zealand; an interconnected variant that reintroduces these links is used for robustness.

Calibration and validation

The New Zealand model is calibrated to public New Zealand datasets through a dedicated refinement step (Supplementary Method 2). Thermal marginal costs and the wind and solar capacity-factor targets are taken from the MBIE Electricity Demand and Generation Scenarios 2024, installed capacities from the Transpower Security of Supply Annual Assessment 2025, hydro inflow time series and 2018 actual generation from the Electricity Authority EMI database, the Cook Strait link rating and efficiency from the Transpower grid planning guidelines, and reservoir storage volumes from the NZX hydro reservoir report [23,29–31].

The Irish model is calibrated to Ireland's official 2030 decarbonisation scenario, the fleet delivered by the EirGrid Generation Capacity Statement and the Climate Action Plan, with thermal costs and plant parameters drawn from public Irish sources, principally the National Energy and Climate Plan 2024 and the Single Electricity Market generation dataset, with their provenance documented [32,33]. The islanded 2030 system sheds a small quantity of load, 7.90 GWh or 0.018% of demand, at moments of simultaneous low wind and high demand; this scarcity cost is spatially uniform and is separated from the generation siting signal by an explicit value-of-lost-load decomposition described below.

Both national fleets are official 2030 forward scenarios rather than realised systems, the New Zealand fleet following the MBIE Electricity Demand and Generation Scenarios and the Irish fleet the EirGrid Generation Capacity Statement and Climate Action Plan, and both therefore carry the delivery uncertainty inherent in any forward projection; we treat them symmetrically on this basis. The Irish model yields a renewable-electricity share of 71.4%, below the 80% Climate Action Plan electricity target, so it is a conservative rather than an optimistic reading of the scenario, and Irish renewable electricity had already reached roughly 40% by 2023. Each calibrated baseline reproduces its official 2030 reference dispatch for every technology before any load is injected (Supplementary Fig. 1, New Zealand; Supplementary Fig. 2, Ireland), with the headline calibration of both baselines summarised in Supplementary Table 1 and the consistency of the modelled combined-cycle-gas price-setter with official market data set out in Supplementary Discussion 1.

The injection experiment

To measure the spatial cost of siting hyper-scale demand we add a single firm load at one candidate node and re-solve the entire system, then read off how much the optimal annual cost rises. The added load is constant, inelastic and weather-independent, which is the defining electrical signature of a hyper-scale data centre: it draws the same power around the clock, it does not curtail when prices rise, and it is uncorrelated with wind or solar availability. Holding the load profile identical across every node and every country is what makes the experiment a controlled one, so that any difference in the resulting cost must come from where the load connects, not from what kind of load it is. We test three sizes, 100, 300 and 500 MW, spanning the plausible range from one hyper-scale training facility to several co-located campuses and bracketing the official 2030 data-centre demand projections for both systems; individual AI-focused sites are already reported at this scale, from the low hundreds of megawatts to the gigawatt range [4]. For every single solution the network is reloaded fresh from disk before the load is added, so no run can inherit dispatch or expansion state from another; this rules out path-dependence as an explanation for any equivalence-class structure we find.

The candidate nodes are not chosen at random or by size alone. They are placed to span the structural extremes of each grid, so that if even the most physically dissimilar nodes return the same siting cost, a single-class result cannot be dismissed as an artefact of having sampled only similar locations. Five archetypes are targeted in each country: the largest demand centre, the second demand centre, a renewable-rich node, a node with little or no local generation that can be served only across the transmission network, and a balanced mixed node.

In New Zealand the eight candidate nodes (Fig. 1) are: Auckland (North Island, the largest demand centre at about 27% of national load); Waikato-Huntly (North Island, co-located with the Huntly thermal complex that carries the marginal CCGT and coal units); Wellington (North Island, the northern landing of the Cook Strait HVDC link and a transmission bottleneck); Manawatu (North Island, a wind-generation corridor); Northland (North Island, the network periphery, remote from the thermal cluster); Canterbury-Waitaki (South Island, a major hydro catchment); Otago-Clutha (South Island, a hydro generation centre); and Southland-Manapouri (South Island, hydro-rich, co-located with the Tiwai Point aluminium smelter and identified by MBIE as a primary data-centre development zone). Five sit in the North Island and three in the South Island, so the set straddles the Cook Strait HVDC boundary by design.

In Ireland the five county candidate nodes (26-bus network) are: Dublin (the largest load, on the east coast and the existing data-centre cluster); Cork (the second load centre, in the south); Wicklow (the strongest wind resource among the candidate counties); Longford (a remote midland node with essentially no local generation, reachable only across the ring, which is the critical pure-transmission test); and Louth (a balanced node). The 8-bus analytical-limit network samples the same five archetypes at coarser resolution.

The annualised marginal siting cost is the change in optimal system cost divided by the injected capacity, that is the difference between the injected-case and baseline optimal system costs divided by the injected capacity, expressed in EUR/MW/yr and, for the New Zealand cross-check against retail data,

converted to NZD/MWh at 0.6034 EUR per NZD over the 8,760-hour year. Because the islanded Irish baseline sheds a small amount of load, an injection there raises the raw marginal by a spatially uniform value-of-lost-load term; we therefore decompose the Irish marginal into a scarcity component, equal to the change in shed energy valued at the value of lost load and divided by the injected capacity, and a generation component that carries the locational signal, and we classify on the generation component.

Equivalence-class criterion

We borrow the term equivalence class from its standard mathematical sense: a set of elements that are interchangeable under a stated relation. Here the relation is "produces the same marginal siting cost", and two candidate nodes belong to the same class when their marginal siting costs are indistinguishable. We operationalize indistinguishability as a cross-node spread below 1%, the spread being the range of nodal marginal costs divided by their mean; for Ireland the classification is applied to the generation component of the decomposed marginal. The 1% threshold is deliberately loose relative to the effects we measure, so that the classification is conservative: the Irish nodes fall two to three orders of magnitude below it, and the New Zealand inter-island gap sits at roughly 4%, far above it, so neither verdict is sensitive to where the threshold is drawn. We report the raw spread at every load size alongside the verdict, so the reader can see the classification rather than take it on trust.

The number of classes is the scientific payload of the experiment, because it translates directly into what a planner can and cannot do. A single class means the marginal cost of serving a new hyper-scale load is, to within measurement noise, the same wherever in the country it connects: there is no locational price signal to exploit, no market mechanism can steer siting on cost grounds, and only physical reinforcement or administrative allocation remains. Two or more classes mean the opposite: a cost-relevant boundary exists, the cheaper class is identifiable, and a locational price can in principle steer load toward it. The whole paper turns on the finding that this count is set by network topology rather than by the generation mix, so New Zealand separates into two classes divided by the Cook Strait HVDC link while Ireland, a meshed all-AC ring, collapses to one.

Robustness and perturbation suite

The New Zealand result is tested across eight sensitivity dimensions, converter efficiency, South Island generation capacity, carbon and gas prices, discount rate, demand growth, transmission expansion, and weather year, applied to all eight candidate nodes at three load sizes (415 optimisation runs in total; the full design and per-scenario results are reported in Supplementary Discussion 3). The single infeasibility encountered, Manawatu at 500 MW, falls in the separate loss suite and reflects a physical bottleneck rather than a numerical failure. The Irish result is tested through a parallel suite of ten operating-parameter perturbations plus frozen-transmission and line-thermal-limit tests, solved at both the 26-bus and 8-bus resolutions (on the order of 315 optimisation runs; Supplementary Discussion 2). Because coal and peat are retired in the 2030 fleet, thermal-regime robustness is carried by the gas and carbon perturbations rather than by a reordering of the merit order. Both suites confirm the headline classification holds without exception, except in the frozen-transmission case noted in Section 2.4.

The weather years are chosen on physical grounds, not for convenience, and the choice differs between the two systems because their flexibility comes from different resources. New Zealand is hydro-dominated, so the relevant inter-annual variation is reservoir inflow: 2013 is a dry year in the ERA5 record [34], in which low inflow forces more thermal dispatch and shifts the marginal supplier from combined-cycle gas toward coal, raising annual system cost to roughly 853 M EUR; 2018 is a wet reference year, also the calibration year, at about 589 M EUR; and 2019 is a recent intermediate year at about 684 M EUR. Spanning the dry-to-wet range is the strongest available test of whether the siting structure depends on the identity of the marginal fuel, since the dry year is precisely when that identity changes. Ireland, by contrast, has negligible hydro storage and is wind-dominated, so the relevant variation is the wind resource rather than hydro inflow; we use 2018 as the shared ERA5 calibration year and add 2020 (a high-wind year) and 2021 (a low-wind year) to span the inter-annual wind-resource range, confirming that the single-class result is not a coincidence of one wind year (Supplementary Fig. 3; Supplementary Method 3). The recent ERA5 window excludes the 1990s drought extremes, which we note in the Limitations as a bound on the claimed invariance.

Model scope and self-validation

We state the reduced physical scope of the analysis plainly. Power flow is a lossless linear transport with zero reactance, so the model captures energy balance and line capacity but not alternating-current security: it excludes N-1 contingencies and voltage and reactive-power limits, whose inclusion would add localized nodal stresses without altering the macro-scale topological structure we report. Alternating-current line capacity is co-optimized in both systems, yet baseline expansion is negligible, so the spatial cost surface reflects the existing network rather than a rebuilt one; the Cook Strait link is held fixed and non-expandable, which is what preserves the inter-island gap. Hydro reservoirs are energy-limited by annual inflow and priced at an endogenous water value rather than a fixed cost, so they are neither free nor must-run; under deterministic perfect foresight this water value tracks the gas price, which renders the 99.97% gas-marginal share an upper bound that omits the occasional spill-driven low-price hours of real operation. We confirmed that no generator exceeds its rated output. New Zealand sheds no load; the islanded Irish 2030 system sheds a small, spatially uniform quantity equal to 0.018% of demand, which is removed from the siting signal by the value-of-lost-load decomposition.

System scale and comparability

The two systems are well matched for a controlled comparison: both are national power systems of comparable scale, electrically islanded here by design (New Zealand genuinely, Ireland through the removal of its cross-border links), within about 8% of each other in energy and peak (Table 1), and both share the same combined-cycle-gas price-setter under the same flexibility trap, so the marginal economics of serving an added megawatt are governed by identical mechanics in each. They differ in the composition of their demand rather than its magnitude, but this does not confound the experiment: the injected treatment is held identical across both countries by construction, so any contrast in spatial response is attributable to network topology rather than to the size or shape of the shock or the pre-

existing demand pattern. The residual demand differences, New Zealand's large Tiwai Point industrial block and Ireland's east-coast data-centre concentration, together with the material 1.4 to 7.4% of peak demand that a single hyper-scale facility represents, are set out in Supplementary Discussion 6.

Declarations

Data and code availability

The New Zealand calibration data, refinement pipeline and analysis scripts are available in the project repository, with full source provenance documented in its data statement. The Irish model is built on PyPSA-Earth with a county-level configuration and the documented calibration chain. Raw weather reanalysis and bulk geographic inputs are obtained through the standard PyPSA-Earth download pipeline from their original public publishers.

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Figures

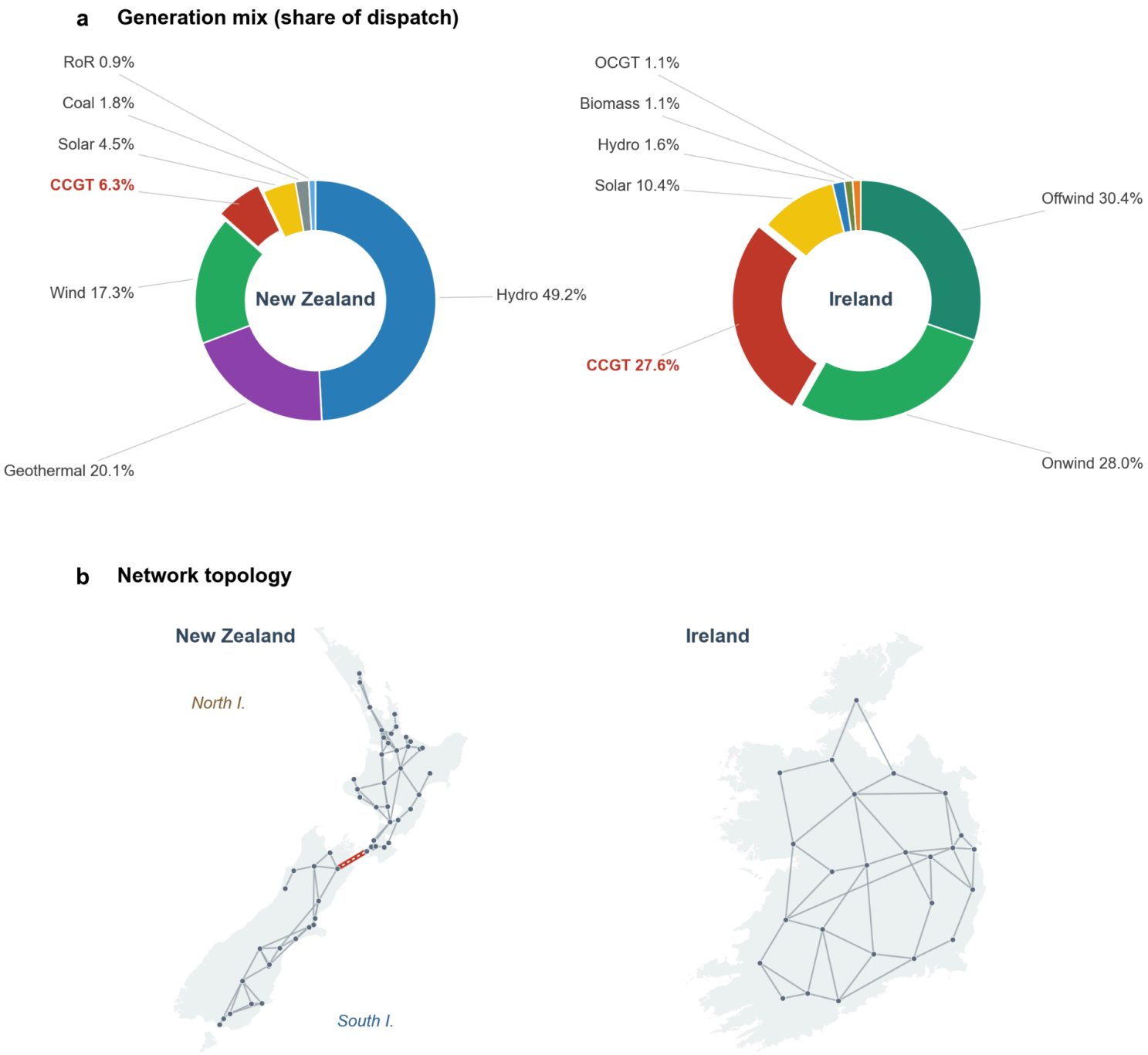


Figure 1

Baseline dispatch by technology and network topology of the New Zealand and Ireland systems. a, Annual dispatch by technology for the two official 2030 scenarios. Both are renewable-rich (New Zealand 91.95%, Ireland 71.4%), and in both the combined-cycle gas (CCGT) wedge, exploded, is the marginal price-setter, at 74.96 and 115.8 EUR/MWh respectively. b, Transmission skeletons reprojected to metric coordinates (EPSG:2193 New Zealand, EPSG:2157 Ireland). New Zealand is two island grids joined by the single Cook Strait HVDC link (red; 1,400 MW, η = 0.96); Ireland is a closed AC ring. Grey lines are uniform width and do not encode capacity.

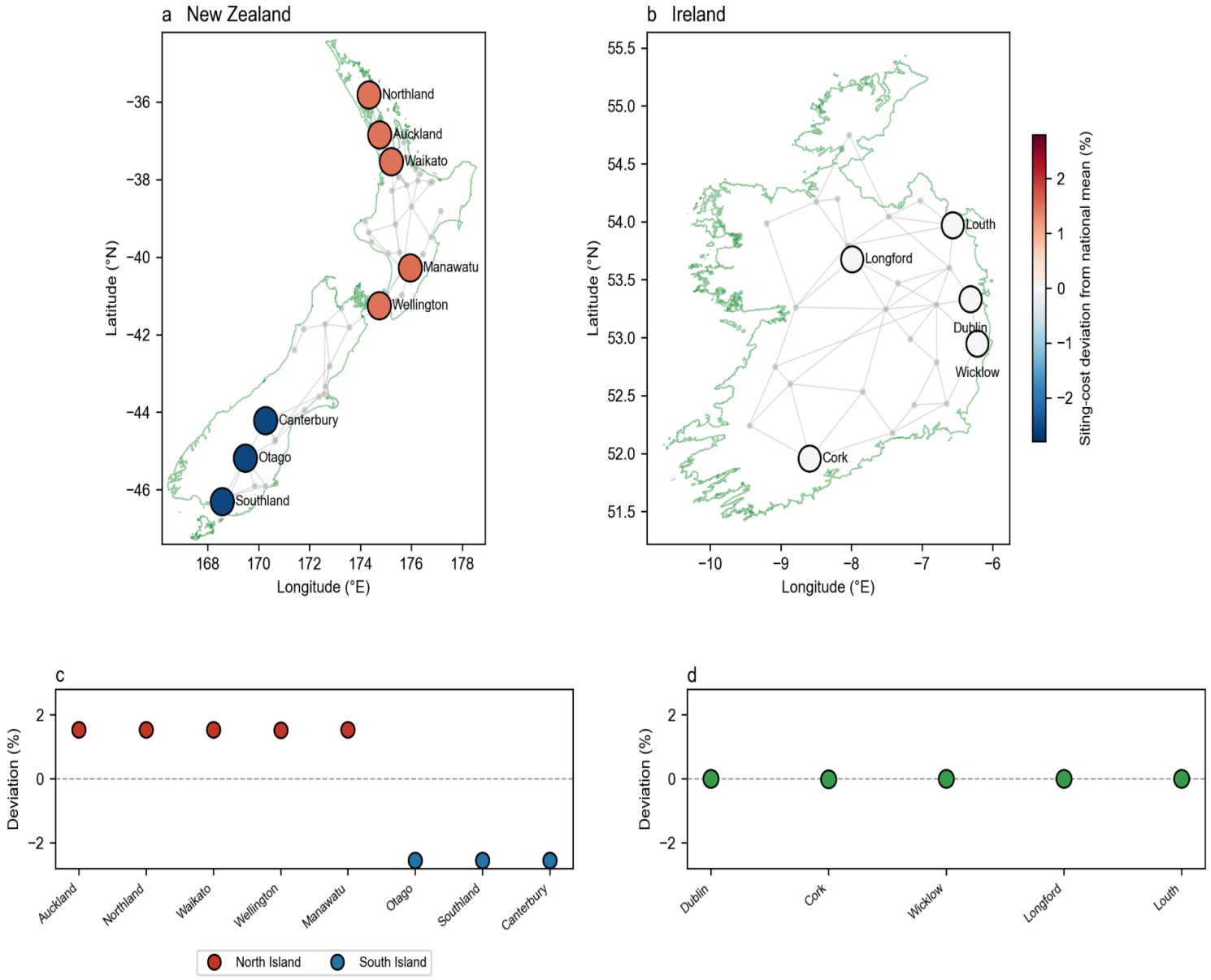


Figure 2

Spatial distribution of the marginal siting cost across candidate nodes in the two systems. a, New Zealand: the eight candidate nodes, colored by the deviation of their 100 MW siting cost from the national mean, split into two equivalence classes that coincide with the island boundary, 4.18% apart. b, Ireland: the five county candidate nodes, on the same scale (generation-cost deviation after the uniform value-of-lost-load rent is removed), form a single unbroken plateau, spread 0.016%. c, Per-node siting-cost deviation for New Zealand, ordered North Island then South Island, separating into two bands 4.18% apart. d, Per-node generation-cost deviation for the five Irish counties, all falling on a single line 0.016% wide, on the same vertical scale as c. Faint grey markers are non-candidate buses; coastlines from GADM.

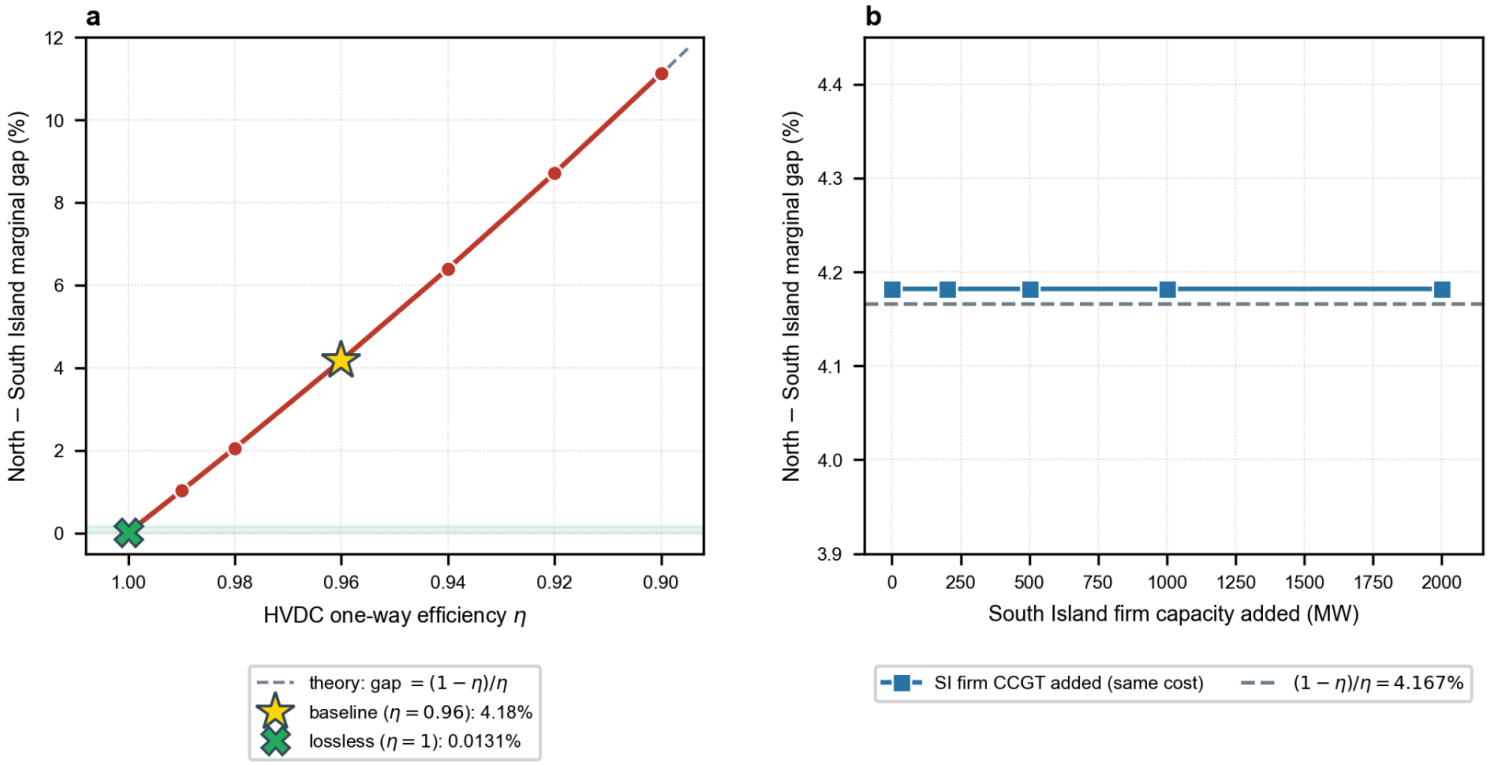


Figure 3

New Zealand inter-island premium versus HVDC converter efficiency and added South Island firm capacity. a, HVDC efficiency sweep. The North-minus-South Island marginal premium (red, seven steps) against the one-way converter efficiency η (0.90 to 1.00, x-axis inverted). The gap tracks the analytic (1−η)/η (dashed) at every step: 11.13% at η = 0.90, 4.17% at the η = 0.96 baseline (gold star), and a collapse to 0.013% at the lossless limit η = 1.00 (green cross), where the two classes merge. b, Invariance to South Island generation. Adding same-cost South Island firm gas from 0 to 2,000 MW leaves the premium fixed at 4.18% with the added plant undispatched; the dashed line marks (1−η)/η = 4.167%.

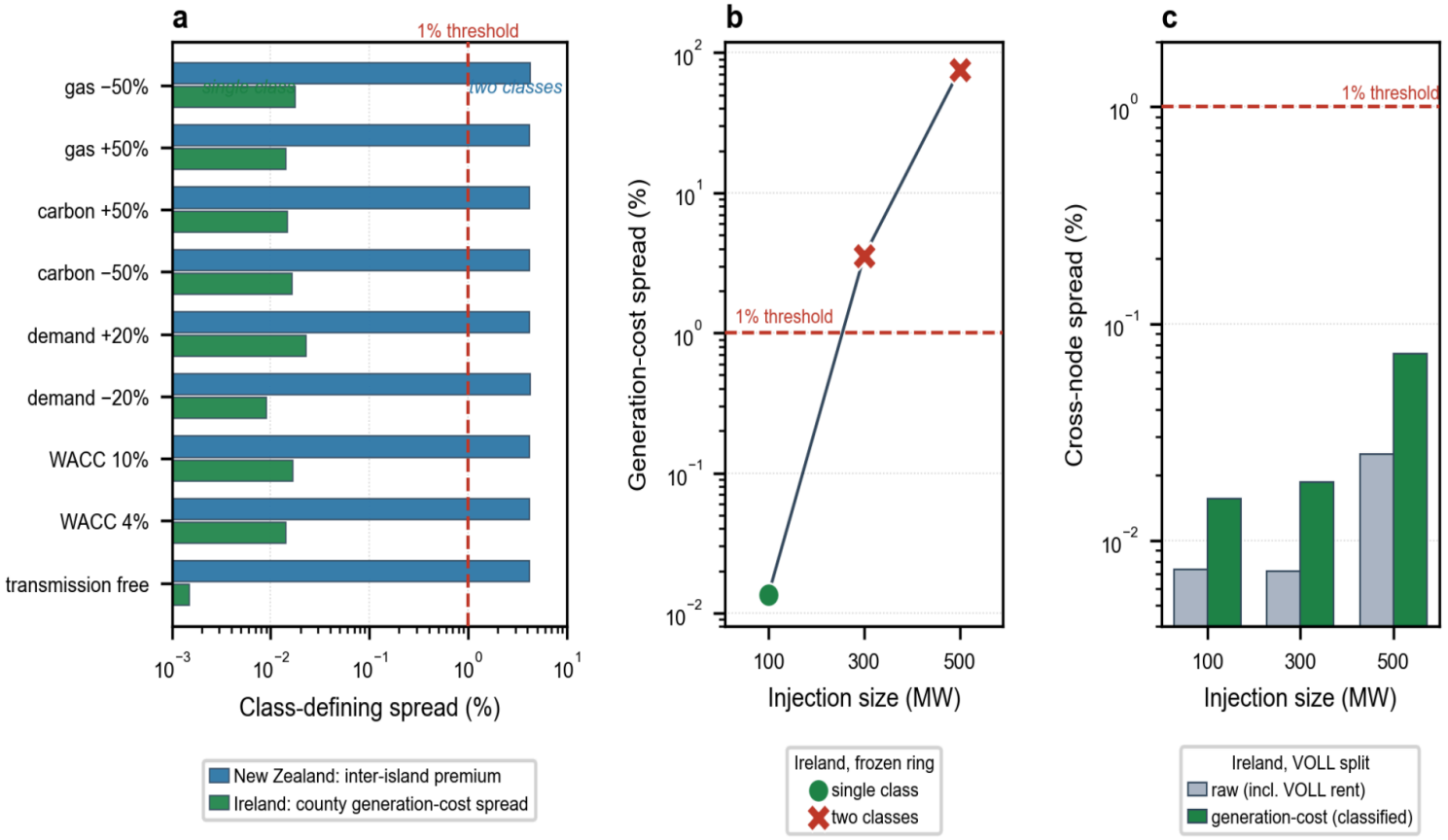


Figure 4

Sensitivity of the class-defining cost spread to operating-parameter perturbations, a frozen transmission network, and load-value decomposition in New Zealand and Ireland. a, Class-defining spread across the shared perturbation suite (log scale), showing the New Zealand inter-island premium (blue) and the Ireland county generation-cost spread (green) against the 1% equivalence threshold (red dashed); the premium remains above the threshold and the spread one to two orders of magnitude below it at every perturbation. b, Frozen-network re-test (Ireland): a single class at 100 MW; the remote Longford node congests and separates into a second class at 300 MW and above (values in Section 2.4). c, Value-of-lost-load decomposition (Ireland): the raw cross-node spread (grey) carries a uniform scarcity rent; removing it leaves the generation-cost spread (green) on which nodes are classified, both far below the 1% threshold at all three load sizes.