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Bitcoin mining as supply-side flexibility in Irish wind energy integration

M. Sarnecki, N. Burke *

Faculty of Engineering, Department of Polymer & Mechanical Engineering, Technological University of the Shannon, Athlone Campus, University Road, Athlone, Co, Westmeath, Ireland

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A B S T R A C T

Ireland recorded 10.1% of available wind generation (1.3 TWh) as dispatch-down in 2024, with 2025 data showing a further rise to 11.4% as capacity additions continue to outpace transmission investment. This paper evaluates co-located Bitcoin mining as a supply-side flexibility mechanism for absorbing curtailed energy under Irish Single Electricity Market conditions. Using hourly 2024 data for a modelled 100 MW wind farm, a deterministic revenue-maximisation model is solved across six scenarios spanning 0–90 MW of mining capacity and two ASIC hardware generations. A 20 MW installation of current-generation hardware (16 J/TH) absorbs 83% of annual dispatch-down energy, raises total system revenue by 32%, and increases the effective capacity factor from 29% to 32%; scaling to 30 MW raises absorption to 93%. Legacy hardware at 98 J/TH is uneconomic under all 2024 scenarios. Investment viability depends on the magnitude of the spread between Bitcoin price and network hashrate growth rates rather than on the absolute price level.

1. Introduction

Ireland recorded 10.1% of available wind generation as dispatch-down (DD) in 2024, equivalent to 1.3 TWh of generating capacity instructed offline not because of insufficient demand but because the transmission network cannot accommodate it. This share has risen from 4 to 5% in 2014–2016 and, with 2025 data already showing 11.4% (EirGrid, 2026), shows no sign of stabilising as renewable capacity additions continue to outpace network investment (EirGrid, 2025a; SEAI, 2025).

The structural drivers of DD have changed materially. System Non-Synchronous Penetration (SNSP) limits contributed around 16% of total DD through 2020 but accounted for only 1.7% of instructed curtailment in 2024 (EirGrid, 2021, 2025b). Contemporary DD originates principally from local transmission constraints in western regions where wind capacity has outgrown grid infrastructure, compounded by system-wide requirements for minimum synchronous generation to maintain inertia and frequency stability. Ireland's Climate Action Plan targets 8 GW onshore and 5 GW offshore wind by 2030, yet transmission investment lags capacity additions by three to five years (DECC, 2023a), widening the gap between installed capacity and exportable output.

The economic cost of DD operates through two channels. First, curtailment forfeits generator revenue directly and raises the delivered cost of renewable electricity (Newbery, 2025). Second, the progressive retirement of synchronous plant increases demand for ancillary services like frequency response, voltage support and inertia, all procured through *EirGrid's* DS3 programme and recovered via transmission charges that contribute to Ireland's elevated wholesale prices relative to European peers (FfE, 2025). A co-located demand asset capable of absorbing curtailed energy at zero marginal system cost and qualifying as a system service provider in its own right addresses both channels simultaneously.

This study investigates Bitcoin mining deployed as a Supply-Side Response (SSR) mechanism: a co-located, dispatch-optimised demand asset that absorbs generation upstream of the grid connection point, effectively expanding local export capacity without network reinforcement. Unlike conventional demand response, which operates at system scale through aggregated price signals, SSR concentrates the curtailment burden at nodes where flexible absorption capacity exists. The technical characteristics that make mining suited to this role are examined in Section 2.4.

Using hourly 2024 data for a modelled 100 MW Irish wind farm, a deterministic revenue-maximisation model is specified and solved across 8760 dispatch intervals and six operational scenarios spanning

* Corresponding author.
E-mail addresses: A00267089@student.tus.ie (M. Sarnecki), niall.burke@tus.ie (N. Burke).

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0–90 MW of co-located mining capacity and two ASIC hardware generations. DD absorption rates, revenue impacts, and investment returns are quantified under conservative assumptions. The paper contributes to the emerging literature on computational demand as a grid flexibility resource, extending existing results to the regulated small-island conditions of the Irish Single Electricity Market and its Renewable Electricity Support Scheme contract-for-difference structure, neither of which has been examined in prior peer-reviewed work.

2. Background and literature review

2.1. Dispatch-down evolution in Ireland

Republic of Ireland wind capacity doubled from 2.5 GW in 2014 to approximately 4.9 GW in 2024, yet delivered generation increased by only 120% over the same period (Table 1). This divergence reflects escalating DD rather than resource variability: average wind speeds remained broadly stable at 5.4–6.2 m/s throughout the decade (Table 1; Open-Meteo, 2026). DD has scaled proportionally with capacity additions, rising from 4 to 5% in 2014–2016 to 10.1% of available wind generation in 2024, a 468% increase in energy dispatched-down (EirGrid, 2025a; SEAI, 2025), with 2025 data showing a further rise to 11.4% (EirGrid, 2026), as illustrated in Fig. 1. New installations increasingly displace existing generation rather than adding net supply, a consequence of transmission capacity limits, non-synchronous penetration thresholds, and insufficient flexible demand or export capacity.

DD exhibits pronounced regional variation, with northwest counties averaging 19% against approximately 9% in the midlands, reflecting the mismatch between Ireland's Atlantic wind resource concentration and eastern demand centres (EirGrid, 2022b). The transmission system, designed for centralised hydrocarbon generation, is structurally ill-suited to distributed renewable injection.

The Irish government's Climate Action Plan sets a target of maintaining DD below 7% by 2030, a threshold already breached in 2024. *EirGrid's Shaping Our Electricity Future Roadmap* projects that, without appropriate flexibility measures, surplus renewable generation could exceed 20% of available capacity by 2030 (EirGrid, 2022a). SEAI's analysis of dispatch-down trajectories indicates that curtailment could reach at least 16% by 2030 even with flexibility measures in place, including synchronous condensers, medium-term storage, and demand response (SEAI, 2024).

2.2. Literature review: bitcoin mining for grid flexibility

Bastian-Pinto et al. (2021) demonstrated positive net present values for wind-mining co-location using real options valuation at curtailment rates as low as 20%, though their binary operational assumption, of either full capacity or shutdown, does not capture the continuous modulation possible with modern ASICs. Bruno et al. (2023) found that grid-connected mining in Texas can induce additional renewable capacity but increases carbon emissions through gas generation unless miners operate as demand response resources; the behind-the-meter arrangement modelled in scenarios S1–S2 eliminates grid draw entirely, removing the emissions channel they identify. Lotfi et al. (2023) developed robust optimisation for mining site selection, accepting 4.94% lower expected profits for improved worst-case performance, a trade-off that reflects Bitcoin price volatility as a primary project risk. Velický (2023) compared mining with battery storage and hydrogen electrolysis, finding superior returns above 15% curtailment, though excluding the grid service revenue stacking examined here. Lashkaripour et al. (2025) identify renewable intermittency as a structural disadvantage for green miners in the proof-of-work competition, since miners reliant on intermittent supply operate at lower utilisation than continuously supplied competitors; the own-supply supplementation modelled in scenario S2 addresses precisely this utilisation penalty. Empirically, Lal et al. (2023, 2024) documented 32 Texas wind and solar projects earning $47 million from pre-commercial mining operations. Carter et al. (2023) reported that 2 GW of registered mining capacity in ERCOT provided sub-four-minute demand response, generating $25 million in revenues during Winter Storm Elliott whilst avoiding an estimated $100 million in system costs (ERCOT, 2023). These studies validate technical feasibility but are confined to deregulated markets; the Brazilian case, where curtailed renewable generation exceeded 32 TWh between 2021 and 2025 and several wind operators have since moved to deploy co-located mining in the northeast, illustrates that curtailment at the scale projected for Ireland by 2030 can attract market-led solutions without regulatory mandate (Reuters, 2025).

No peer-reviewed study examines Bitcoin mining in a small island system with high renewable penetration under a regulated market structure. Ireland-specific gaps encompass techno-economic modelling under I-SEM price dynamics, regulatory pathway analysis for grid code integration, and comparative assessment against planned infrastructure investments. This study addresses the first two through operational simulation and policy framework analysis.

2.3. Irish electricity market structure

The Irish Single Electricity Market (I-SEM) is an all-island wholesale market operated jointly by *EirGrid* (Republic of Ireland TSO) and *SONI* (System Operator for Northern Ireland), encompassing Day-Ahead

Table 1
Republic of Ireland wind capacity, generation, and curtailment, 2014–2025 (EirGrid, 2025a) (SEAI, 2025) (EirGrid, 2026). All figures cover the Republic of Ireland transmission system only; Northern Ireland data are excluded.

Year	Average wind speeds [m/s]	Wind capacity installed [MW]	Wind generation available [GWh]	Wind generation actual [GWh]	Dispatch-Down energy [GWh]	Dispatch-Down [%]	Wind capacity factor [%]
2014	5.62	2268	5281	5058	223	4.0%	28%
2015	6.04	2447	6867	6536	330	5.0%	32%
2016	5.57	2795	6301	6099	177	2.8%	27%
2017	5.87	3303	7532	7229	277	3.7%	27%
2018	5.83	3668	9181	8680	457	5.0%	29%
2019	5.85	4113	10,293	9532	711	6.9%	28%
2020	6.22	4323	12,656	11,138	1448	11.4%	30%
2021	5.41	4333	10,326	9527	752	7.3%	25%
2022	5.88	4528	11,934	10,895	988	8.3%	28%
2023	5.86	4731	12,608	11,422	1124	8.9%	28%
2024	6.03	4934	12,478	11,145	1266	10.1%	26%
2025	6.93	5095	12,904	11,351	1476	11.4%	26%

Note: DD [%] is taken directly from *EirGrid's* published annual curtailment report (EirGrid, 2025a): 1266 GWh dispatched down from 12,478 GWh available = 10.1% (2024). The 67 GWh gap between this figure and the implied available-minus-actual difference reflects frequency response reductions, which *EirGrid* excludes from its dispatch-down methodology by definition.

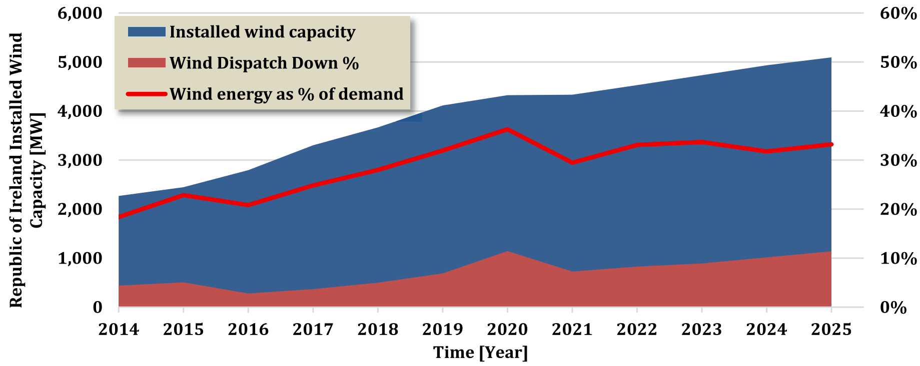

Fig. 1. Republic of Ireland Dispatch-Down (DD), installed wind capacity, and wind energy as % of demand between 2014 and 2024 (EirGrid, 2025a).

(DAM), Intraday, and Balancing markets. The DAM, where 75–85% of wholesale volume trades (Nord Pool, 2024; EPEX SPOT SE, 2024), exhibits substantial volatility: prices ranged from −€50/MWh to €487/MWh in 2024, with 88 h of negative pricing during high-wind, low-demand periods (SEMOpx, 2024). Generator support has evolved from the Renewable Energy Feed-in Tariff (REFIT) regime (2006–2015), which provided fixed premiums of €71–77/MWh supporting 2.5 GW of deployment, to competitive RESS auctions operational from 2020, offering two-way Contracts for Difference (CfDs) with strike prices averaging €74–100/MWh across five completed rounds.

Under RESS CfDs, generators receive or pay the difference between strike price and DAM price for positive price periods only; negative price exposure remains with the generator, forcing curtailment or uncompensated generation. While Ireland's grid code contains no explicit provisions for mining loads, non-discriminatory access applies: operations meeting power quality and fault-ride-through standards qualify for connection (EirGrid, 2024a, 2024b, 2024c).

2.4. Bitcoin mining: technical characteristics and economics

Bitcoin mining involves solving cryptographic hash functions to validate transactions and append new blocks to the blockchain. The Bitcoin protocol targets one block every ten minutes through an automatic difficulty adjustment, yielding approximately six blocks per hour ($B_h \approx 6$), with the winning miner receiving a block subsidy plus transaction fees. Global mining energy consumption is estimated at 150–180 TWh annually in 2024 (Cambridge Centre for Alternative Finance, 2024, 2025).

From a power system perspective, three characteristics make mining particularly suited to a flexible load role. Location independence reduces deployment barriers: power and internet connectivity suffice, and containerised hardware can be installed or relocated rapidly without site-specific civil works. Instantaneous load control enables sub-second demand response: ASICs activate or deactivate in seconds without hardware wear and operate at continuous rated power draw between dispatch instructions. Price responsiveness aligns operational incentives with system conditions: profitability depends on the ratio of mining revenue to electricity cost, where revenue is jointly determined by Bitcoin price, global network hashrate, installed capacity, and block rewards — the relationship formalised in Eqs. 1–3 below (KPMG, 2023; Hajiaghapour-Moghimi et al., 2024).

ASIC efficiency has improved by approximately two orders of magnitude since network inception, declining from around 800 J/TH in 2014 to approximately 12 J/TH for current frontier hardware, as Fig. 2 illustrates alongside the corresponding collapse in S9 revenue per MWh since that unit's 2016 launch. The *Antminer* S21 Hydro, selected for this study at 16 J/TH, reflects commercially deployable technology available to a project financed in 2024 rather than the absolute efficiency frontier. By 2025, *Antminer* S9 revenue per MWh had fallen below economically viable thresholds under all modelled market conditions and the unit is excluded from the investment analysis.

Mining revenue is calculated in three steps; notation for all symbols is provided in Appendix A. An ASIC's reward share is proportional to its hashrate relative to global network hashrate (Eq. 1), converted to euro terms via the prevailing Bitcoin price (Eq. 2), and normalised to energy consumption to yield revenue per MWh (Eq. 3).

$$R_{ASIC,BTC}\ [BTC/h] = \left(\frac{H_{ASIC}\ [EH/s]}{\mathrm{H}_{Global}\ [EH/s]}\right) \times (B_R[BTC/Block] + B_T[BTC/Block]\ ) \times B_h[Blocks/h] \tag{1}$$

$$R_{ASIC,€}\ [€/h] = R_{ASIC,BTC}\ [BTC/h] \times P_{BTC}\ [€/BTC] \tag{2}$$

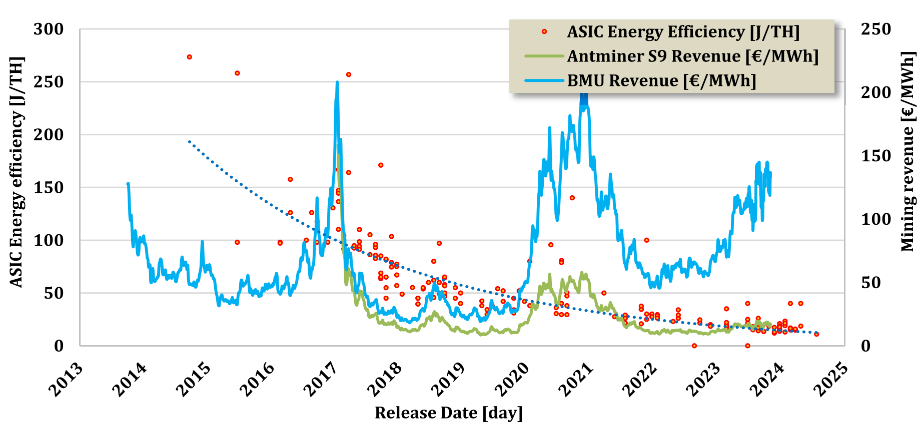

Fig. 2. ASIC energy efficiency & bitcoin mining revenue, 2014–2025. Data: manufacturer specs & blockchain.com

$$R_t\ [€/MWh] = \frac{R_{ASIC,€}[€/h]}{\dot{P}_{ASIC}\ [kW]} \times 1,000 \quad (3)$$

The Bitcoin block reward halves every 210,000 blocks, approximately every four years, compressing miner revenue from newly issued BTC. The fourth halving of 19 April 2024 reduced the block subsidy from 6.25 BTC to 3.125 BTC per block, the value used throughout this study. Transaction fees of approximately 0.16 BTC per block averaged 5% of total block rewards in 2024 but can spike above 50% during periods of network congestion, introducing a positive skew in hourly mining revenue. Fig. 3 illustrates Bitcoin price and global network hashrate from 2009 to 2025.

Fig. 4 shows the distribution of modelled S21 Hydro revenues throughout 2024, with the majority of hours falling between €100 and €160/MWh and a positive right tail reflecting periods of elevated network profitability.

2.5. Supply-side response (SSR) and flexible digital loads

Traditional demand response operates at system scale through mechanisms such as time-of-use tariffs, EV scheduling, and load shedding. SSR targets individual renewable generation nodes through co-located flexible digital loads, enabling an SSR-equipped wind farm to emulate semi-dispatchable behaviour by dynamically adjusting on-site consumption and thereby controlling net grid export.

When DD is triggered by negative prices, system-wide curtailment, or local transmission constraints, the SSR controller compares grid export revenue (€/MWh from I-SEM or RESS CfD) against flexible load revenue (€/MWh from mining, per Eq. 3), diverting energy to the load when mining profit exceeds export value. This converts an otherwise uncompensated generation reduction into a revenue-generating operational decision.

Beyond direct DD absorption, SSR monetises energy that would otherwise be spilled, improves project IRR through higher asset utilisation, and allows SSR-equipped sites to function as distributed energy sinks. Under the current *EirGrid* practice of uniform pro-rata curtailment, all wind farms share the burden regardless of whether they can productively use the constrained energy. The economic significance of this allocation rule is sharpened by the distinction between average and marginal curtailment: Newbery (2023), in an analytical model calibrated to Ireland, shows that the marginal unit of wind capacity is curtailed several times more often than the average, while investment signals reflect only average curtailment. A framework that concentrates DD signals at SSR-equipped nodes would preserve export capability at non-flexible sites while eliminating spill where flexible loads exist; total curtailment volume would be unchanged, but its economic cost would fall. The asymmetric risk structure of RESS CfDs, where generators bear full negative price exposure without compensation, reinforces this rationale: price-responsive co-located loads absorb precisely the generation that contract structures cannot protect.

3. Methodology

3.1. Model overview and data sources

A hypothetical 100 MW wind farm (20 × 5 MW turbines) was modelled using publicly available data to ensure reproducibility whilst avoiding commercial sensitivity. Hourly wind speeds at 100 m hub height for 2024 were obtained from *Open-Meteo's* historical weather API for central Ireland (53.6°N, −7.9°W). Theoretical power output ($\dot{P}_e$) was derived from the standard wind power equation:

$$\dot{P}_e[W] = 0.5 \bullet C_p\,[-] \bullet A_r\left[m^2\right] \bullet \rho_a\left[kg/m^3\right] \bullet v_a^3[m/s] \quad (4)$$

Where ρ_a is air density, A_r the rotor swept area, v_a the wind speed, and C_p the overall system coefficient of performance. A generic turbine power curve with cut-in and cut-out speeds of 3 m/s and 24 m/s respectively was applied.

The modelled wind farm, with an 11.7% dispatch-down rate, represents a moderately constrained asset; in western regions, higher curtailment strengthens the viability of demand-side solutions. The 11.7% dispatch-down rate is constructed from EirGrid actual and available wind generation data covering the full Republic of Ireland wind fleet, both transmission- and distribution-connected, rather than from the published instructed dispatch-down series. An hourly dispatch-down fraction was computed as 1 − (actual / available), with the source data aggregated from quarter-hourly to hourly resolution. Hours with a fraction below 0.04%, the series median, were set to zero as negligible curtailment, which concentrates dispatch-down in the high-wind hours where it physically arises. This fraction was then applied to the modelled farm's available generation profile from Eq. 4 to give the hourly wind-farm dispatch-down volume. The construction therefore differs from EirGrid's published 10.1% figure in both basis and scope: resting on the available-minus-actual difference, it captures the frequency-response reductions that EirGrid excludes from its instructed dispatch-down methodology, and its coverage extends to the full wind fleet rather than the TSO-connected generation to which the published figure is restricted. On the published TSO-connected data, the available-minus-actual rate for 2024 is 10.7% (1333 of 12,478 GWh; Table 1), with the remaining difference to 11.7% attributable to the broader fleet coverage; the scope distinction is discussed further in Section 3.5.

3.2. Market and mining parameters

The wind farm operates under full Day-Ahead Market (DAM) exposure without support from the Renewable Electricity Support Scheme (RESS) or a Power Purchase Agreement (PPA), establishing a conservative lower-bound baseline for wind farm revenue. DAM prices for 2024 were sourced from SEMOpx, averaging €108.9/MWh. Realised wind-weighted prices were lower at €86.9/MWh, reflecting price cannibalisation: wind generation concentrates during high-wind periods when wholesale prices are suppressed by excess supply, while output is

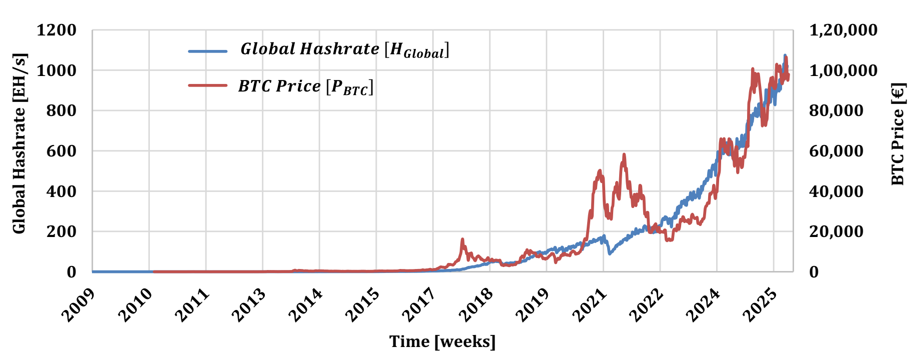

Fig. 3. Historical Bitcoin price [€] and global network hashrate [EH/s], 2009–2025.

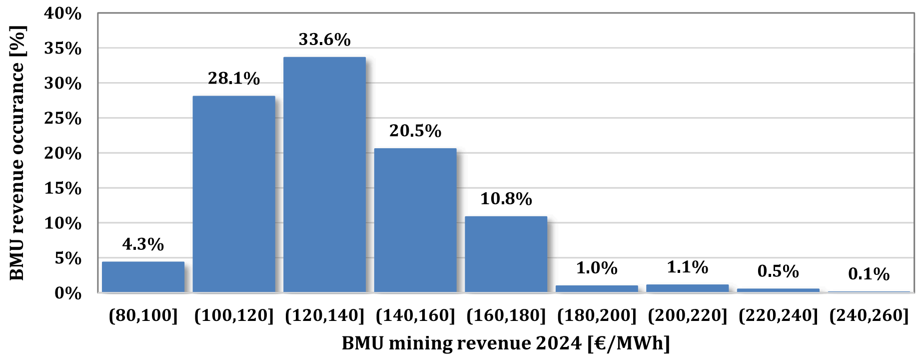

Fig. 4. Distribution of Bitcoin Mining Unit (BMU) system revenues and percentage of time (S21 Hydro), 2024.

absent during high-price, low-wind periods. This figure is derived from the sum of hourly products ($q_{g,t} \bullet P_t^{DAM}$), less Generator Transmission Use of System (G-TUoS) charges of €8058/MW/year (EirGrid, 2024a, 2024b, 2024c), divided by total grid exports of 255,023 MWh. No Demand Transmission Use of System (D-TUoS) charge is applied, as this levy falls on electricity drawn from the network and does not apply to dispatched generation. For grid-connected BMU loads in scenarios S3–S5, however, D-TUoS charges are applicable and are modelled at rates reflecting the 46% increase applied in 2024/2025; these represent a material component of import costs in those scenarios. Full charge parameters are presented in Table B.1.

Bitcoin mining revenue (R_t) is calculated on an hourly basis using blockchain network data. The Bitcoin price (P_{BTC}) is taken from historical daily closing values, ranging between €35,000 and €103,000 during 2024. Global network hashrate (H_{Global}) is represented as a 7-day moving average, varying between 415 and 890 EH/s.

Block rewards (B_R) are fixed at 3.125 BTC per block for the 2024 simulation year, following the halving of 19 April 2024. The next halving, projected for approximately April 2028, falls within the six-year appraisal horizon and is applied as a step-down in block subsidy in the forward projections of Section 3.6. Transaction fees (B_T) are incorporated using the full observed 2024 time series, which is positively skewed with occasional spikes exceeding 1 BTC per block during periods of network congestion; a constant median of 0.16 BTC per block is adopted for forward projection sensitivity analysis.

Two ASIC technologies are selected to represent the spectrum of commercially relevant mining hardware. The *Bitmain Antminer* S9, operating at approximately 98 J/TH, represents legacy equipment at the margin of economic viability under 2024 conditions. The *Bitmain Antminer* S21 Hydro, operating at 16 J/TH, represents current-generation commercial deployment and is selected as a conservative analytical baseline rather than a state-of-the-art upper bound, reflecting hardware available to a project financed in 2024. Key technical specifications for both units and full transmission charge parameters are presented in Table B.1.

3.3. *Formal optimisation framework*

For clarity, the notation used in this section is summarised in Appendix A. Let $T = \{1, 2, \ldots, 8{,}760\}$ denote the set of hourly dispatch intervals in the analysis year. For each $t \in T$, define the following decision variables: $q_{g,t} \geq 0$ as energy exported to the grid; $q_{m,t} \geq 0$ as on-site wind energy consumed by the Bitcoin Mining Unit (BMU); $q_{\mathrm{dd},t} \geq 0$ as dispatch-down energy absorbed by the BMU; $q_{\mathrm{imp},t} \geq 0$ as energy imported from the grid for mining; and $s_t \geq 0$ as residual curtailed wind generation. The installed BMU capacity $K_m \geq 0$ (MW) is treated as a scenario parameter rather than a decision variable; it is held fixed at each model run and parameterised over the set $\{5, 10, \ldots, 90\}$ MW in 5 MW increments, as described in Section 3.4.

Five parameters enter the model. Available wind energy output P_t^w is derived from Eq. 4. The hourly dispatch-down volume D_t is treated as an exogenous parameter reflecting the EirGrid dispatch instruction. P_t^{DAM} is the Day-Ahead Market price in €/MWh. The BMU is modelled as a price-taker in the DAM: grid electricity is purchased at the prevailing hourly clearing price, and the mining load, at 5–90 MW against all-island system demand, is too small to influence market outcomes. Because the DAM price series is exogenous historical 2024 data, no feedback from mining demand to prices arises by construction. Mining revenue per MWh, R_t, is calculated from Eqs. 1–3. The transmission charge C_t is set to €31/MWh, representing the D-TUoS rate applicable in scenarios S3–S5; in S1–S2, grid imports are prohibited by scenario definition, so C_t is inoperative.

3.3.1. *Objective function*

The objective is to maximise net system revenue over the analysis period. The fixed G-TUoS charge (€8058/MW/year) is excluded from the dispatch objective because it does not vary with the hourly dispatch decision; it is captured in the investment-level NPV and IRR calculations reported in Section 4.3.

$$\max_{q_{g,t}, q_{m,t}, q_{dd,t}, q_{imp,t}, s_t} \Pi = \sum_{t \in T} \Big[q_{g,t} \bullet P_t^{DAM} + R_t \bullet \left(q_{m,t} + q_{dd,t} + q_{imp,t} \right) - \left(P_t^{DAM} + C_t \right) \bullet q_{imp,t} \Big] \tag{5}$$

subject to constraints (6)–(12), which define the feasible dispatch set at each hour.

$$P_t^w = q_{g,t} + q_{m,t} + q_{dd,t} + s_t, \forall t \in T \tag{6}$$

$$q_{g,t} \leq P_t^w - D_t, \forall t \in T \tag{7}$$

$$D_t = s_t + q_{dd,t}, \forall t \in T \tag{8}$$

$$q_{dd,t} + q_{m,t} + q_{imp,t} \leq K_m, \forall t \in T \tag{9}$$

$$q_{imp,t} \leq MIC, \forall t \in T \tag{10}$$

$$q_{m,t} \cdot q_{imp,t} = 0, \forall t \in T \tag{11}$$

$$q_{g,t}, q_{m,t}, q_{dd,t}, q_{imp,t}, s_t \geq 0, \forall t \in T \tag{12}$$

Constraint (6) is the hourly wind energy balance, allocating available wind generation across grid export, own-supply mining, dispatch-down absorption, and residual spillage. Constraint (7) limits grid export to the level permitted by the EirGrid dispatch instruction. Constraint (8) splits the dispatch-down volume between BMU absorption and residual spillage, while constraint (9) caps total BMU consumption at the installed mining capacity. Constraint (10) bounds grid imports by the Maximum Import Capacity and applies in scenarios S3–S5 only; in S1–S2, grid imports are prohibited by scenario definition. Constraint (11) is the mutual exclusivity condition specific to scenario S4, under which the BMU may draw from own-supply wind or grid imports in any given hour, but not both simultaneously. Constraint (12) imposes non-negativity on all decision variables.

Constraint (7) is implied by (6), (8), and (12): substituting (8) into (6) gives $q_{g,t} = P_t^w - D_t - q_{m,t}$, which satisfies $q_{g,t} \leq P_t^w - D_t$ directly from the non-negativity of $q_{m,t}$. Constraint (7) is retained for the economic interpretation of the dispatch-down mechanism.

3.3.2. Activation conditions

The profit-maximising activation conditions follow as first-order optimality conditions from the objective. Substituting constraints (6) and (8) jointly into Eq. 5 yields the separable reduced form, in which the per-hour objective decomposes into four independent terms whose coefficients determine the sign of each decision variable. From (6), $q_{g,t} = P_t^w - q_{m,t} - q_{\mathrm{dd},t} - s_t$; substituting (8) ($s_t = D_t - q_{\mathrm{dd},t}$) gives $q_{g,t} = P_t^w - D_t - q_{m,t}$. The per-period objective then becomes:

$$\Pi_t = \left(P_t^{\mathrm{w}} - D_t\right)\cdot P_t^{\mathrm{DAM}} + \left(R_t - P_t^{\mathrm{DAM}}\right)\cdot q_{\mathrm{m,t}} + R_t\cdot q_{\mathrm{dd,t}} + \left(R_t - P_t^{\mathrm{DAM}} - C_t\right)\cdot q_{\mathrm{imp,t}}$$

The first term, $\left(P_t^{\mathrm{w}} - D_t\right)\cdot P_t^{\mathrm{DAM}}$, is fixed at each t and is unaffected by the dispatch decision. The remaining three coefficients yield the following activation conditions.

Dispatch-down absorption activates whenever the coefficient on $q_{\mathrm{dd,t}}$ is positive. Because DD energy carries zero opportunity cost as it cannot be exported under the *EirGrid* dispatch instruction the relevant coefficient is simply R_t. The activation condition is therefore:

$$R_t > 0 \tag{13}$$

This condition is satisfied in virtually all hours under 2024 market conditions, where mining revenue remained positive throughout the year. In practice, DD energy is absorbed up to the installed capacity limit K_m imposed by constraint (9); any dispatch-down volume exceeding that limit is spilled as residual curtailment s_t. Note that a reader substituting only constraint (6), without (8), into Eq. 5 would obtain the incorrect threshold $R_t > P_t^{\mathrm{DAM}}$, which overstates the opportunity cost of DD energy. The correct threshold arises from joint substitution of (6) and (8).

Own-supply mining activates when the coefficient on $q_{\mathrm{m,t}}$ is positive, that is, when mining revenue exceeds the opportunity cost of diverting wind output away from grid export:

$$R_t > P_t^{DAM} \tag{14}$$

Grid-import mining activates when the coefficient on $q_{\mathrm{imp,t}}$ is positive, that is, when mining revenue exceeds the combined cost of purchasing and transmitting electricity from the grid. This condition applies only in scenarios S3–S5:

$$R_t > P_t^{DAM} + C_t \tag{15}$$

where C_t is the Demand Transmission Use of System (D-TUoS) charge, set to €31/MWh in accordance with the applicable tariff (CRU, 2023; CRU, 2024). In S1–S2, $q_{\mathrm{imp,t}} = 0$ by scenario definition and C_t is therefore inoperative. Eq. 15 makes the link between the import cost term in Eq. 5 and the dispatch decision explicit: imports occur only in hours where mining revenue covers both the energy price and the transmission charge.

Because the per-period objective is separable for given K_m, contemporaneous revenue and cost signals fully determine the optimal activation choice at each t, the dispatch problem reduces to closed-form threshold evaluation across all 8760 intervals, with optimal dispatch following directly from Eqs. 13–15 at each hour. The mutual exclusivity constraint (11), applicable in scenario S4 only, restricts the BMU to drawing from own-supply wind or grid imports in any given hour, but not both simultaneously: at most one of $q_{m,t}$ and $q_{\mathrm{imp},t}$ may be positive. Under all conditions this constraint is non-binding, because the net revenue per MWh from own-supply $\left(R_t - P_t^{\mathrm{DAM}}\right)$ exceeds that from grid import $\left(R_t - P_t^{\mathrm{DAM}} - C_t\right)$ by exactly C_t in every hour. Own-supply is therefore always preferred when available, and grid imports are only drawn when own-supply is exhausted; the two sources are never simultaneously optimal. The S4 results consequently track S2 closely, with marginal differences arising only when own-supply energy is insufficient to meet profitable mining demand. BMU capacity K_m is parameterised from 5 MW to 90 MW in 5 MW increments across each of the six operational scenarios defined in Table 2.

3.4. Operational scenarios and revenue models

Six scenarios evaluate different integration strategies between the wind farm and co-located Bitcoin mining, as summarised in Table 2. Three revenue models capture increasing operational complexity. Model 1 sells all wind output at DAM prices with no mining integration, establishing the €86.9/MWh weighted-average baseline reported in Table B.4. Model 2 is a theoretical hybrid in which 80 MW operates under a RESS-3 CfD while 20 MW remains merchant with co-located mining absorbing DD; it is not simulated as a discrete scenario but provides the RESS-supported revenue columns in Table B.4 as an indicative upper bound, based on the RESS-3 weighted-average strike price of €100.47/MWh (DECC, 2023b). Model 3 permits dynamic selection across DD consumption, own-supply arbitrage, and grid imports, and is theoretically optimal but operationally complex.

3.5. Model assumptions and limitations

Several assumptions bound the scope of this analysis. The wind farm is represented using a homogeneous wind resource that excludes wake interactions and array losses, effects that influence both total output and its temporal distribution. ASIC hardware is assumed to respond instantaneously to dispatch instructions, consistent with the sub-second controllability of modern mining systems, though real deployments may experience communication delays or ramping constraints. Hardware efficiency is held constant over the equipment lifetime, abstracting from degradation, firmware optimisation, or generational improvements.

The principal economic assumption is perfect price foresight: electricity prices, Bitcoin prices, and global network hashrate are treated as known *ex ante*, enabling optimal allocation between grid export and mining. Demand response and ancillary service revenues are excluded, a conservative choice given potential DS3 eligibility for large flexible loads. The historical price-leads-hashrate relationship is assumed to persist throughout the appraisal horizon (Fantazzini and Kolodin, 2020; Kubal and Kristoufek, 2022).

The behind-the-meter arrangement modelled in scenarios S1–S2 is predicated on a private wire connection under Ireland's emerging Private Wires Policy (DECC, 2025). This framework remains under active development, and the absence of a finalised regulatory pathway represents a material implementation risk not captured in the revenue modelling.

Collectively, these assumptions produce upper-bound revenue estimates. A natural extension would treat Bitcoin price and global network hashrate as correlated stochastic processes and apply Monte Carlo simulation to generate distributions of NPV and payback period rather than point estimates, drawing on the lag structure documented by Fantazzini and Kolodin (2020) and Kubal and Kristoufek (2022). Such an approach would also permit explicit modelling of halving-event discontinuities in block subsidy and their interaction with hashrate adjustment dynamics.

A limitation of this study is that post-halving revenue dynamics were modelled using a CAGR methodology with constant transaction fees, rather than through stochastic simulation. Constructing post-halving simulations would require reliable forward estimates of network hashrate, Bitcoin price trajectories, and transaction fee dynamics, parameters that carry substantial uncertainty and are difficult to justify empirically. As a result, the sensitivity analyses may understate or overstate the

Table 2
Summary of modelled scenarios.

Scenario	Code	Energy Sources	Key Feature	Demand network capacity charge
Baseline	**S0**	N/A	No mining; full exported	Wind farm only
DD-Only	**S1**	Dispatch-down Only	Mining exclusively on Dispatch-Down (DD) energy	Wind farm only
DD-Priority	**S2**	Dispatch-down with Own-supply when profitable	Mining Prioritises DD, supplements with wind	Wind farm only
Grid-Supplemented	**S3**	Dispatch-down with Grid imports	Mining Prioritises DD, imports when profitable	Wind farm and BMU
Either-Or	**S4**	Dispatch-down with Own-supply OR grid imports	Mining selects most profitable single source	Wind farm & BMU
Full-Flexibility	**S5**	Dispatch-down with Grid AND own-supply	Mining uses all profitable sources simultaneously	Wind farm & BMU

Table 3
S2 NPV and IRR outcomes after 6-year investment (20 MW, Antminer S21 Hydro).

		BTC Network Global Hashrate CAGR [%]											
		5%		**10%**		**15%**		**20%**		**25%**		**30%**	
		NPV	**IRR**	**NPV**	**IRR**	**NPV**	**IRR**	**NPV**	**IRR**	**NPV**	**IRR**	**NPV**	**IRR**
BTC Price CAGR [%]	**5%**	**-10.1 M**	**-5.7%**	**-15.2 M**	**-19.3%**	**-19.4 M**	**N/A**	**-22.9 M**	**N/A**	**-25.9 M**	**N/A**	**-28.5 M**	**N/A**
	10%	**-4.2 M**	**3.2%**	**-10.1 M**	**-5.7%**	**-14.9 M**	**-18.4%**	**-19.0 M**	**N/A**	**-22.5 M**	**N/A**	**-25.4 M**	**N/A**
	15%	**2.4 M**	**10.4%**	**-4.4 M**	**2.9%**	**-10.1 M**	**-5.7%**	**-14.8 M**	**-17.6%**	**-18.7 M**	**N/A**	**-22.1 M**	**N/A**
	20%	**9.6 M**	**16.7%**	**1.8 M**	**9.8%**	**-4.7 M**	**2.5%**	**-10.1 M**	**-5.7%**	**-14.6 M**	**-17.0%**	**-18.4 M**	**N/A**
	25%	**17.7 M**	**22.3%**	**8.6 M**	**15.9%**	**1.2 M**	**9.2%**	**-4.9 M**	**2.2%**	**-10.1 M**	**-5.7%**	**-14.4 M**	**-16.4%**
	30%	**26.5 M**	**27.6%**	**16.1 M**	**21.3%**	**7.7 M**	**15.1%**	**0.7 M**	**8.7%**	**-5.1 M**	**2.0%**	**-10.1 M**	**-5.7%**

Note: N/A indicates that projected cash flows do not achieve cost recovery within the six-year appraisal horizon; no real IRR exists.

range of plausible outcomes in the post-halving period.

The dispatch-down rate of 11.7% used in this analysis exceeds EirGrid's published figure of 10.1%. This discrepancy reflects differences in measurement basis and scope rather than a data error: the modelled series rests on the available-minus-actual difference and covers both TSO- and DSO-connected wind farms, while the published figure reports instructed dispatch-down on TSO-connected generation only (Section 3.1). Future studies may consider disaggregating TSO and DSO curtailment rates where the investment case pertains specifically to a single connection type.

3.6. Sensitivity analysis: bitcoin price and network hashrate trajectories

Mining revenue per megawatt-hour is jointly determined by Bitcoin price and global network hashrate, both coupled through the network difficulty adjustment mechanism; Fantazzini and Kolodin (2020) and Kubal and Kristoufek (2022) document a price-leads-hashrate lag of one to six weeks. As the diagonal of Table 3 illustrates, combinations in which both variables grow at equal rates yield the same NPV regardless of their absolute level, reflecting partial cancellation of opposing effects.

To assess how investment viability responds to plausible divergences from this co-movement, a sensitivity analysis was conducted for the 20 MW S2 configuration. Annual revenue per MWh was recalculated for each year of the appraisal period by applying compound annual growth rates (CAGRs) to 2024 base-year values of €90,000/BTC (approximating the year-end 2024 closing price of €90,074) and 780 EH/s, modelling both trajectories as exponential functions. These projected revenues were applied within a discounted cash flow framework holding all other parameters constant: a DD absorption volume of 28,081 MWh per annum (83.1% of the 33,808 MWh baseline), capital expenditure of €34.7 million, fixed annual operating costs of €0.42 million, and a discount rate of 8%. The opportunity cost of diverting own-supply wind to mining, estimated at €7.42 million per year as the revenue foregone relative to the S0 baseline, is deducted from net cash flows in each period. NPV and IRR are computed over a six-year horizon, consistent with the S21 Hydro equipment lifetime, across BTC price and hashrate CAGRs ranging from 5% to 30% per annum in 5 percentage point increments. The block subsidy is stepped down from 3.125 to 1.5625 BTC per block at the projected April 2028 halving, so revenues in the post-2028 years of the horizon reflect the reduced subsidy. Results are presented in Table 3.

Further analysis of the impact of dispatch down (DD) rates and Bitcoin price on discounted payback period is presented in Table 4. In this analysis, global network hashrate is held constant at 780 EH/s across all scenarios. Additionally, Bitcoin price is treated as static over the six-year investment horizon, implying that mining revenue per MWh remains constant within each scenario. This approach isolates the effects of DD availability and price level on project viability, allowing for clear comparison across site and market conditions, independent of temporal dynamics such as network growth or price evolution.

Table 4
Discounted payback period [years] for a 20 MW S2 BMU installation under static 2024 market conditions, across BTC price and dispatch-down rate combinations (hashrate fixed at 780 EH/s, six-year appraisal horizon, 8% discount rate).

		Dispatch-down [%]				
		25%	20%	15%	10%	5%
BTC price [€]	160,000	1.08	1.11	1.13	1.17	1.20
	140,000	1.29	1.33	1.38	1.42	1.47
	120,000	1.61	1.67	1.74	1.84	2.07
	100,000	2.13	2.29	2.60	2.99	3.56
	80,000	3.44	4.07	N/A	N/A	N/A
	60,000	N/A	N/A	N/A	N/A	N/A
	40,000	N/A	N/A	N/A	N/A	N/A

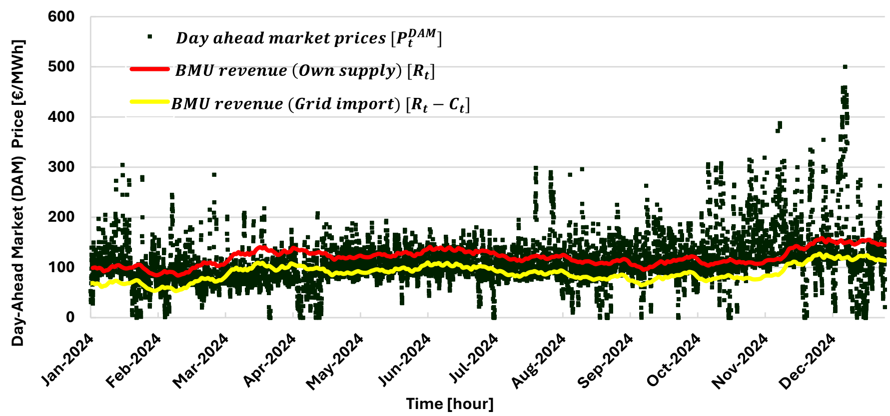

Fig. 5. 2024 Irish DAM prices (black) versus BMU revenue for S21 Hydro (red) and transmission charges (yellow). (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

4. Results

4.1. Baseline performance (S0)

The modelled 100 MW wind farm generated 288,831 MWh of available energy in 2024, of which 33,808 MWh (11.7%) was subject to DD. Grid exports totalled 255,023 MWh, yielding a 29.1% capacity factor, which is conservative relative to *EirGrid's* system average of 33% and reflects the inland location modelled, the generic power curve applied, and the 11.7% DD rate reducing exportable output (EirGrid, 2025a). Revenue under pure DAM exposure reached €22.2 million after G-TUoS charges, equivalent to €86.9/MWh, which is below the €108.9/MWh system-average DAM price due to the negative correlation between wind output timing and wholesale prices.

Negative or near-zero DAM prices occurred in approximately 1% of hours (~88 h), clustered in off-peak, high-wind periods characterised by renewable oversupply (SEMOpx, 2024). These episodes reflect system-wide curtailment pressure: excess generation suppresses wholesale prices, eroding wind farm margins or triggering RESS CfD top-up obligations on the state. Fig. 5 overlays 2024 hourly DAM prices against S21 Hydro mining revenue thresholds; crossover points identify intervals in which mining generates higher returns than grid export, providing the economic basis for the DD-priority dispatch logic applied in subsequent scenarios. The mining revenue thresholds presented in Fig. 5 represent gross revenue and exclude operational expenditure.

4.2. Dispatch-down absorption efficiency

DD absorption rises steeply with BMU size before exhibiting clear diminishing returns (Fig. 6). A 20 MW installation captures 83.1% of annual DD energy (28,081 MWh); scaling to 30 MW raises this to 93.4% (31,576 MWh). Beyond 30 MW, marginal absorption gains become negligible: a further 20 MW of installed capacity increases capture by only 6 percentage points (93.4% to 99%), at proportionally rising capital cost.

The capacity factor analysis in Fig. 7 reveals the trade-off inherent in BMU sizing: as system size increases relative to wind farm capacity, DD energy per MW of mining capacity declines, compressing utilisation rates. Under S1 (DD energy only), capacity factors range from approximately 30% at small system sizes to below 5% at 90 MW, indicating that DD volumes alone are insufficient to sustain economically meaningful utilisation at scale. Scenarios incorporating own-supply or grid access (S2–S5) maintain 31–76% utilisation, with the spread narrowing at larger system sizes. A 10 MW BMU achieves 53–73% utilisation across S2–S5, versus 31–56% at 90 MW, reflecting the interaction between DD intermittency and supplementary energy source access. S5, drawing on all three energy sources simultaneously, sustains the flattest utilisation profile, holding 56–76% capacity factors across the full size range.

These two results jointly constrain the optimal sizing decision: absorption efficiency favours larger installations, while capacity factors deteriorate with scale under energy-limited scenarios.

4.3. Revenue enhancement and investment returns

Total system revenue increases across all scenarios relative to baseline (Fig. 8). The S0 baseline generated €22.2 million in 2024, with a weighted-average realised price of €86.9/MWh. Under full-year 2024 average market conditions, the S21 Hydro generated approximately €134/MWh (Table B.4), substantially above this baseline. Under the S2 configuration (DD-priority with own-supply supplement), a 20 MW mining installation raised total system revenue to €29.2 million, a 32% uplift under 2024 market conditions, with the weighted-average revenue per MWh rising to €103.1. A 30 MW installation yielded €31.1 million (+40%), at €108.6/MWh. Where RESS contract coverage is incorporated, these figures strengthen further: the 20 MW + RESS and 30 MW + RESS configurations generate €31.7 million and €33.4 million

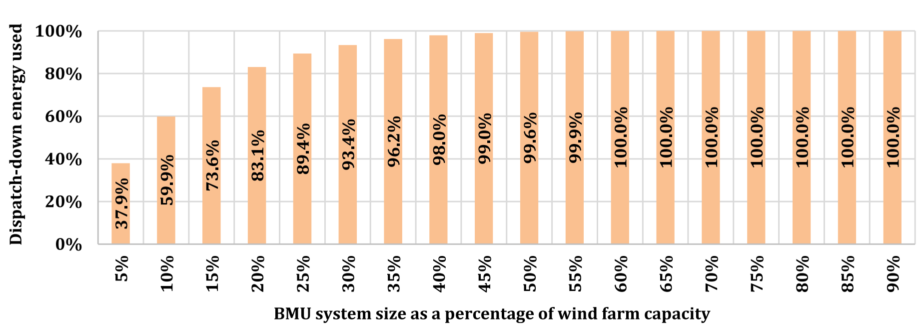

Fig. 6. Dispatch-down energy used [%] by BMU mining systems at various system sizes (all scenarios).

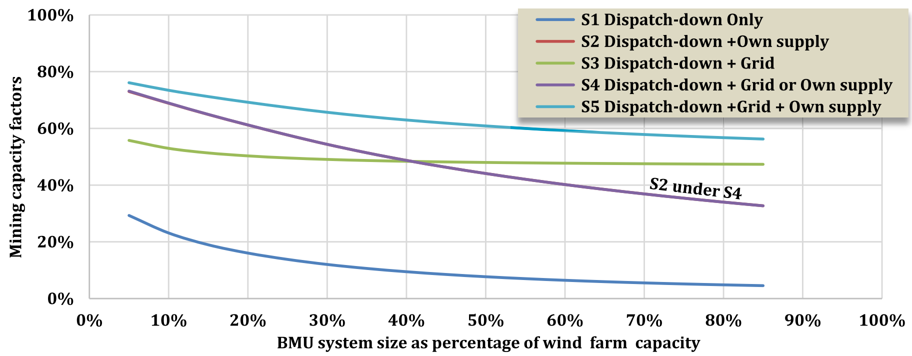

Fig. 7. S21 Hydro BMU mining capacity factors for each scenario across different BMU system sizes.

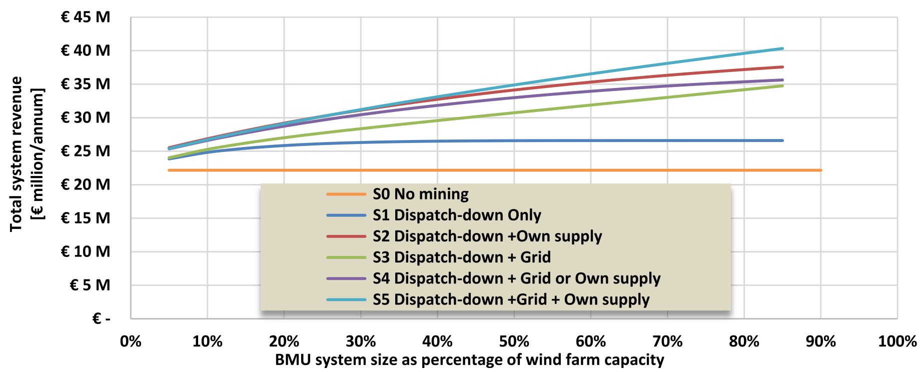

Fig. 8. Total system revenue (wind farm + BMU system) in millions across system size for each scenario.

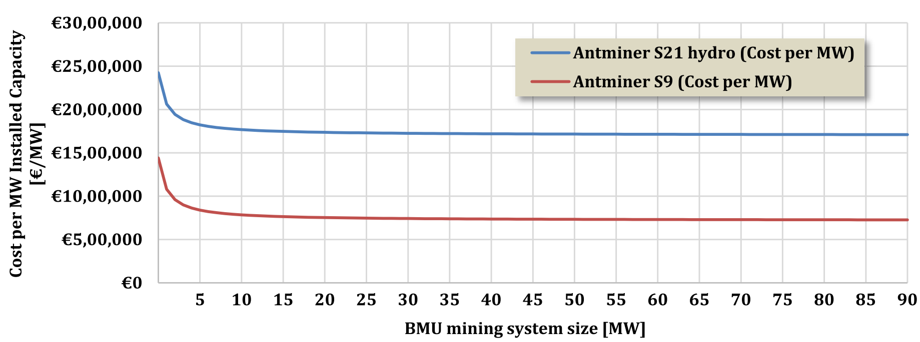

Fig. 9. Estimated BMU system cost per MW of installed capacity across various system sizes (see Table B.3).

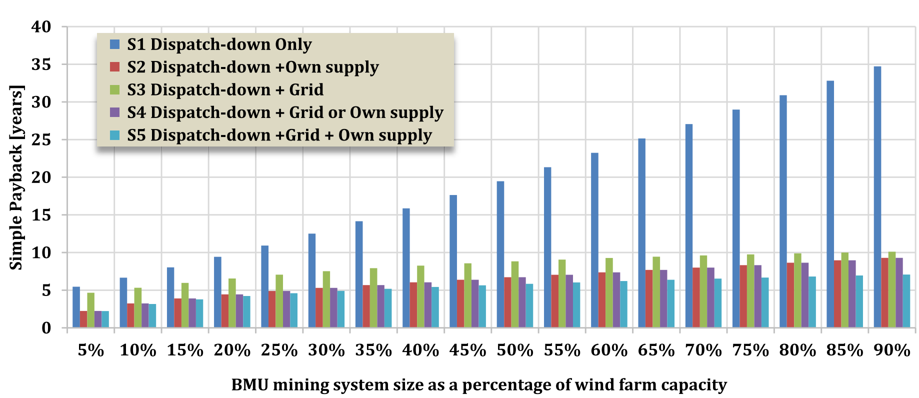

Fig. 10. Static BMU payback periods, S21 Hydro.

respectively, reflecting the additional price floor provided by contract-for-difference support (Table B.4). The RESS sub-scenarios are treated as indicative of the upper bound of revenue potential under current Irish support mechanisms; they are not modelled with full contract specificity and are discussed further in Section 5.

The BMU installation cost curve (Fig. 9) exhibits two phases of scale economies. S21 Hydro costs decline from €2.5 million/MW at 1 MW to €1.74 million/MW at 30 MW, driven by bulk procurement and reduced per-unit engineering overhead. Beyond 30 MW, marginal savings become negligible: expanding from 30 MW to 90 MW reduces per-MW costs by only €0.012 million while yielding minimal additional DD absorption (Fig. 6). This inflection point explains why the 20 to 30 MW range represents the configuration that captures the bulk of scale economies while sustaining high capacity factors (Table B.3).

Fig. 10 presents static payback periods under constant 2024 conditions (11.7% DD), which should be interpreted as upper-bound estimates under prevailing market conditions. Installations in the 5 MW to 20 MW range achieve the most favourable payback periods, typically between ~2.2 and ~ 4.4 years under scenarios S2, S4, and S5. S1, which relies exclusively on dispatch-down energy, was not financially viable under the modelled assumptions. Beyond approximately 40 MW, payback periods exceed 6 years, indicating diminishing returns from further capacity expansion.

4.4. Sensitivity analysis: bitcoin price and network hashrate

Table 3 presents NPV and IRR outcomes for the 20 MW S2 configuration across the CAGR combinations specified in Section 3.6. The 2028 Bitcoin halving is incorporated as a step-down in block subsidy from 3.125 to 1.5625 BTC per block; as the halving is projected for April 2028, a methodological simplification applies the reduced subsidy across the full calendar year rather than from the halving date, which marginally understates revenue in 2028. Transaction fees are held constant at the 2024 median of 0.16 BTC per block throughout the appraisal horizon, and mining hardware is not refreshed; the S21 Hydro units are assumed to remain in continuous operation across the full six-year window.

Table 4 extends the sensitivity analysis by crossing DD rate against Bitcoin price to show how discounted payback period varies across the primary dimensions of site selection (DD intensity) and Bitcoin price level, holding hashrate constant at the 2024 baseline of 780 EH/s. Unlike Table 3, revenue is held static across the appraisal horizon rather than grown by CAGR; the two tables are therefore not directly comparable, but Table 4 isolates the effect of DD availability and prevailing price level on payback independent of trajectory assumptions.

The economic performance of co-located mining is primarily determined by external market conditions, particularly Bitcoin price and global network hashrate, which jointly determine the value of mined Bitcoin per unit of computational work. Table 5 presents the resulting mining revenue per MWh for *Antminer* S21 Hydro and S9 hardware across a range of Bitcoin price (€40,000–€160,000) and global hashrate scenarios (700–1200 EH/s), assuming the 2024 block reward of 3.125 BTC per block plus 0.16 BTC/Block transaction fees. Revenues span €7.1/MWh (low end: €40 k BTC, 1200 EH/s, S9) to €281.5/MWh (€160 k BTC, 700 EH/s, S21 Hydro), a 40-fold range.

5. Discussion

The S2 results extend the findings of Lal et al. (2023, 2024) and Bastian-Pinto et al. (2021) to a regulated small-island market under I-SEM price dynamics and a RESS CfD support structure, neither of which has been examined in prior peer-reviewed work.

The 11.7% dispatch-down rate modelled here bears on a boundary condition in the existing literature. Velický (2023) found mining to offer superior returns to battery storage and hydrogen electrolysis above 15% DD, but did not assess viability below this threshold. The S2 results indicate that positive investment returns are achievable at 11.7% DD when hardware efficiency reaches current-generation levels (16 J/TH) and own-supply supplementation is permitted during low-price periods. Legacy S9 hardware, which generates insufficient revenue per MWh under any 2024 market condition, illustrates that hardware selection is as consequential as site selection, a dimension documented but not fully quantified by Lotfi et al. (2023).

The sensitivity analysis in Table 3 reveals a structural feature of co-located mining investment not apparent from point-estimate analyses: where Bitcoin price and hashrate grow at equal compound rates, NPV is invariant to their absolute level. This follows directly from the price-to-hashrate ratio governing mining revenue per unit of computational work. The practical implication is that investment viability depends on price *outpacing* hashrate growth rather than on a directional bet on appreciation — a condition supported by the documented lag structure (Fantazzini and Kolodin, 2020; Kubal and Kristoufek, 2022), in which price leads hashrate expansion by one to six weeks. Early deployment at constrained sites, before DD volumes attract competing capacity, is therefore a more defensible investment thesis than one premised on sustained price appreciation.

Hardware efficiency also conditions the comparison with alternative curtailment technologies. The S21 Hydro achieves approximately €134/MWh under full-year 2024 average market conditions (Table B.4), substantially above DAM prices during DD periods. Unlike battery storage, mining incurs no round-trip efficiency losses or cycle degradation; unlike hydrogen electrolysis, it requires no downstream offtake

Table 5
BMU Revenue sensitivity [€/MWh] across BTC prices (€40,000–€160,000) and Global hashrates (700–1200 EH/s).

Hashrate →	700 [EH/s]		800 [EH/s]		900 [EH/s]		1,000 [EH/s]		1,100 [EH/s]		1,200 [EH/s]	
Miner type → ↓ BTC Price	S21 hyd	S9	S21 hyd	S9	S21 hyd	S9	S21 hyd	S9	S21 hyd	S9	S21 hyd	S9
€160,000	281.6	48.5	246.4	42.5	219.0	37.7	197.1	34.0	179.2	30.9	164.2	28.3
€140,000	246.4	42.5	215.6	37.1	191.6	33.0	172.5	29.7	156.8	27.0	143.7	24.8
€120,000	211.2	36.4	184.8	31.8	164.2	28.3	147.8	25.5	134.4	23.2	123.2	21.2
€100,000	176.0	30.3	154.0	26.5	136.9	23.6	123.2	21.2	112.0	19.3	102.7	17.7
€80,000	140.8	24.3	123.2	21.2	109.5	18.9	98.5	17.0	89.6	15.4	82.1	14.2
€60,000	105.6	18.2	92.4	15.9	82.1	14.2	73.9	12.7	67.2	11.6	61.6	10.6
€40,000	70.4	12.1	61.6	10.6	54.7	9.4	49.3	8.5	44.8	7.7	41.1	7.1

infrastructure. These characteristics support Velický's (2023) conclusion on the relative attractiveness of computational demand as a curtailment sink, while the present results suggest the viability threshold may be somewhat below 15% DD when current-generation hardware is deployed.

Transaction fees averaged approximately 5% of total block rewards in 2024 but exhibit substantial volatility; the next halving in approximately April 2028 falls within the six-year appraisal horizon and will reduce the block subsidy to 1.5625 BTC per block, after which fee income will constitute a growing share of miner revenue whose trajectory is sensitive to layer-2 protocol adoption.

5.1. System-level implications

The sizing dynamics identified in Section 4.2 carry practical implications for system planning. DD absorption efficiency rises steeply to approximately 93% at 30 MW before exhibiting diminishing returns, while capacity factor declines monotonically with scale. This trade-off is not specific to mining; it reflects the fundamental constraint facing any curtailment-absorption technology when installed absorption capacity exceeds typical dispatch-down duration. The 20–30 MW range represents the configuration at which these competing objectives are best reconciled for a 100 MW wind farm with 11.7% DD; at higher DD rates, the efficient scale shifts upward.

The utilisation suppression identified above is partly a structural artefact of Ireland's *pro-rata* curtailment regime. *Concentrating DD signals at sites equipped with flexible loads would increase utilisation without changing total system curtailment volume.* In access-regime terms, such a mechanism amounts to a targeted form of non-firm access; Simshauser and Newbery (2024) show that the rule by which curtailment is allocated across generators materially affects entry costs and welfare, indicating that the allocation question merits attention independently of the technology absorbing the constrained energy. Carter et al. *(2023) document the operational value of registered mining loads as flexible demand resources in ERCOT, providing empirical grounding for the broader case that co-located mining warrants recognition as a distinct resource class.* The existing *EirGrid* grid code permits mining connections under non-discriminatory access provisions but does not recognise SSR-equipped sites as a distinct resource class eligible for preferential curtailment treatment. Establishing such recognition within the DS3 system services framework would enable the utilisation gains described above. Large flexible loads may also be technically capable of qualifying for Fast Frequency Response and Replacement Margin products given sub-second response capability, though formal qualification would require validation against DS3 performance standards.

5.2. Policy and market design

The modelled returns exclude DS3 ancillary service revenues. At base payment rates of €1.94/MWh for Fast Frequency Response and €2.92/MWh for Primary Operating Reserve (EirGrid, 2022c) — unchanged following the 2024 DS3 tariff review (EirGrid, 2024c) — a 20 MW installation available across 8760 annual hours would generate approximately €0.85 million per year from these two products. Temporal Scarcity Scalar multipliers applicable during high SNSP periods would increase effective revenues further, though precise quantification requires hourly SNSP data beyond the scope of this analysis. This exclusion means the payback periods and NPV figures in Table 3 are conservative to a potentially material extent.

Two safeguards would be necessary in any framework according SSR loads preferential curtailment treatment. Own-supply self-consumption should be subject to a cap expressed as a proportion of monthly generation, to prevent wind farms from effectively converting to dedicated mining facilities at the cost of their renewable export obligation. Sites claiming preferential treatment should be subject to transparent metering and telemetry reporting above a defined capacity threshold, analogous to requirements applied to conventional large loads.

Ireland's Private Wires Policy (DECC, 2025) provides a developing regulatory foundation for behind-the-meter co-location, though its application to large-scale computational loads at grid-connected wind farms remains untested. Regulatory direction has, however, become clearer on the demand side. The CRU's Large Energy Users Connection Policy (CRU, 2025), decided in December 2025, requires new data centre connections above 10 MVA to provide new onsite or proximate dispatchable generation, to procure new renewable generation covering at least 80% of annual demand, and to be assessed on whether the connection lies in a constrained region of the network. A co-located BMU at a constrained wind node is the mirror of this arrangement, generation-sited flexible demand rather than demand-sited generation, and the locational logic of the policy is consistent with the SSR concept, although mining loads were not its subject. Resolving whether co-located mining constitutes a demand connection or a generator auxiliary load represents the most immediate regulatory question for prospective developers.

6. Conclusions

This study examines the technical and economic viability of co-located Bitcoin mining as a supply-side flexibility mechanism for Irish wind farms subject to dispatch-down (DD) curtailment. Using hourly 2024 operational data for a modelled 100 MW wind farm and a deterministic profit-maximisation framework, six operational scenarios were simulated across mining capacities from 0 to 90 MW.

A 20 MW installation emerges as the most effective configuration for moderately constrained sites. At this scale, under 2024 market conditions, 83% of annual DD energy is absorbed while maintaining a 61% mining capacity factor, raising total system revenue by approximately 32% relative to wind-only DAM exposure. Scaling to 30 MW raises DD absorption to 93% but compresses the capacity factor to 52%, with correspondingly longer payback periods. These results are consistent with the recovery magnitudes documented in the Texas studies of Lal et al. (2023, 2024), though the constrained-island context of the Irish market introduces utilisation dynamics not present in ERCOT.

Hardware efficiency is a primary determinant of viability. Current-generation ASIC systems operating at approximately 16 J/TH achieve mining revenues well above DAM prices during curtailment periods, making investment returns sensitive primarily to the price-hashrate spread rather than to the absolute level of either variable. Legacy hardware at 98 J/TH is uneconomic under all 2024 scenarios in Ireland.

Investment viability depends not on Bitcoin price alone but on the spread between Bitcoin price growth and global network hashrate growth. Where these two variables grow in tandem, mining revenue per MWh remains broadly stable and returns accrue primarily from DD absorption rather than price appreciation. Table 3 indicates that positive NPV over a six-year appraisal horizon requires a sustained positive spread between the two growth rates; Table 4 shows that sites with higher DD rates achieve positive payback under a wider range of Bitcoin price conditions, which supports targeting co-located installations at the most constrained nodes in the Irish transmission network.

At system level, co-located flexible demand addresses both drivers of dispatch-down — system-wide curtailment during high-wind periods and localised transmission constraints — without requiring physical network upgrades or regulatory subsidy. Compared with battery storage, hydrogen electrolysis, or transmission reinforcement, the co-investment is privately financed and operationally market-driven; any reduction in curtailment volume at constrained nodes constitutes a system benefit that extends beyond the private return modelled here.

Realising these benefits requires regulatory development. No current framework recognises supply-side responsive demand as an eligible load class for preferential curtailment treatment. A mechanism directing dispatch-down signals toward nodes with absorption capacity would increase utilisation of installed flexible loads without increasing total curtailment volume. Appropriate safeguards — own-supply caps and capacity reporting thresholds — would be necessary to preserve the primary export function of wind generation.

The analysis is based on a deterministic single-year simulation under 2024 conditions; all results should be interpreted as scenario-specific rather than predictive. Future modelling should treat transaction fee income as a stochastic variable over appraisal horizons spanning one or more halving events. The regulatory, Bitcoin market, and Irish electricity price environment will each evolve materially across any plausible investment horizon.

Declaration of generative AI and AI-assisted technologies

During the preparation of this work the authors used *Claude* and *Grok* AI in order to assist with manuscript editing and technical writing clarity. After using these tools/services, the authors reviewed and edited the content as needed and take full responsibility for the content of the published article.

CRediT authorship contribution statement

M. Sarnecki: Writing – original draft, Visualization, Validation, Software, Methodology, Investigation, Formal analysis, Data curation. **N. Burke:** Writing – review & editing, Visualization, Supervision, Project administration, Investigation, Conceptualization.

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Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper. This work has not been published elsewhere and is not under consideration by another journal.

Appendix A

Table A.1
Sets and indices.

Symbol	Description
$t \in T$	Hourly time index, $t = 1, 2, \ldots, 8760$

Table A.2
Input parameters.

Symbol	Description	Units
B_h	Blocks mined per hour	Block/h
B_R	Bitcoin block reward	BTC/block
B_T	Bitcoin transaction fee	BTC/block
P_{BTC}	Bitcoin price	€/BTC
H_{Global}	Global Bitcoin network hashrate	EH/s
H_{ASIC}	ASIC mining unit hashrate	TH/s
P_{ASIC}	ASIC mining unit power consumption	W
η_{ASIC}	ASIC miner efficiency	J/TH
P_t^{DAM}	Day-ahead electricity market price at time t	€/MWh
C_t	D-TUoS energy charge; €31/MWh in S3–S5; zero in S1–S2	€/MWh
P_t^w	Available wind generation at time t	MWh
D_t	Dispatch-down energy available at time t	MWh
K_m	Installed mining capacity; scenario parameter, fixed per run	MW
MIC	Maximum Import Capacity; applicable in S3–S5 only	MW
ρ_a	Air density	kg/m^3
A_r	Rotor swept area	m^2
v_a	Wind velocity at hub height	m/s
C_p	Wind turbine power coefficient	–
$\dot{P}_e$	Electrical power output of wind turbine	W

Table A.3
Derived variables.

Symbol	Description	Units
$R_{ASIC,BTC}$	Mining revenue per ASIC unit (BTC terms)	BTC/h
$R_{ASIC,€}$	Mining revenue per ASIC unit (euro terms)	€/h
R_t	Mining revenue per unit electricity at time t	€/MWh
Π	Total annual net system revenue (objective)	€
Π_t	Net system revenue in period t (reduced form)	€

Table A.4
Decision variables.

Symbol	Description	Units
$q_{g,t}$	Wind electricity exported to the grid	MWh
$q_{dd,t}$	Dispatch-down electricity absorbed by BMU	MWh
$q_{m,t}$	Wind electricity diverted to mining (own supply)	MWh
$q_{imp,t}$	Grid electricity imported for mining; S3–S5 only	MWh
s_t	Residual curtailment (unabsorbed dispatch-down)	MWh

Appendix B. Input data and supplementary results

Table B.1
Comparison of legacy and modern ASIC mining technologies.

	Antminer S9	Antminer S21 Hydro
Release date [Year]	2016	2024
Power of unit [W]	1372	5360
Hashrate per unit [TH/s]	14	335
Price (indicative) [€]	200	4850
ASIC efficiency [J/TH]	98	16
D-TUoS (DTS-T) Capacity charge [€/MW/Month]	1901	1901
D-TUoS (DTS-T) Non- Peak Time of Use [€/MWh]	27.3094	27.3094
D-TUoS (DTS-T) Demand Network Transfer Charge [€/MWh]	3.4947	3.4947

Table B.2
input variables for creating the available wind energy profile.

Parameter	Units	Typical value	Notes
Rated power	[MW]	5	Nameplate capacity
Rotor diameter	[m]	128	64 m radius
Swept area	[m^2]	12,868	used if applying full physical model
Cut-in speed	[m/s]	3	turbine starts producing
Cut-out speed	[m/s]	24	safety shutdown
Coefficient of performance	%	45	
Air density	[kg/m^3]	1.225	standard sea-level condition
Number of wind turbines	[−]	20	Number of wind turbines

Table B.3
Inputs used to calculate the cost per MW in Fig. 9.

Cost	Cost type	Antminer S9	Antminer S21 Hydro
Feasibility studies & grid impact assessment	Fixed	€ 75,000	€75,000
Engineering design & permitting	Fixed	€100,000	€100,000
Substation modification (new feeder bay, relays)	Fixed (partly scalable)	€250,000	€250,000
Control & SCADA integration (SSR logic)	Fixed	€52,500	€52,500
Communication/network infrastructure	Fixed	€20,000	€20,000
Civil works & site prep (access road, foundation)	Fixed portion + small variable	€100,000	€100,000
Electrical cabling from collector bus	Incremental	€80,000	€80,000
Step-down transformers (33 kV → 415 V)	Incremental	€50,000	€50,000
Switchgear, metering, protection	Incremental	€30,000	€30,000
Power-factor correction / filters	Incremental	€20,000	€20,000
Mining containers / housing	Incremental	€115,000	€115,000
ASIC miners (hardware)	Incremental	€230,000	€1000,000
Cooling systems (fans or immersion)	Incremental	€70,000	€175,000
Networking & control for miners	Incremental	€35,000	€35,000
Contingency	Fixed + proportional	13%	13%
Working capital / inventory	Fixed (small)	€37,500	€37,500

Table B.4
Modelled 100 MW wind farm revenue in millions, MWh and GWh for 2024 for S0 & S2, using S21 Hydro BMU.

Metrics	S0	S0	S2	S2	S2	S2
	Baseline	Baseline + RESS	20 MW BMU	20 MW BMU + RESS	30 MW BMU	30 MW BMU+ RESS
BMU Energy Used (Own supply, DD, or grid imports)	0.0 GWh	0.0 GWh	107.2 GWh	122.9 GWh	142.9 GWh	160.6 GWh
Grid Exported Energy	255.0 GWh	255.0 GWh	175.9 GWh	160.2 GWh	143.7 GWh	126.0 GWh
BMU Mining Revenue	0.0 M	0.0 M	14.4 M	16.5 M	19.2 M	21.5 M
Wind Farm Grid Supply Revenue	22.2 M	24.8 M	14.7 M	15.3 M	11.9 M	11.9 M
Total System Revenue	22.2 M	24.8 M	29.2 M	31.7 M	31.1 M	33.4 M
Weighted-Average BMU Mining Revenue	€0.0/MWh	€0.0/MWh	€134.8/MWh	€133.9/MWh	€134.7/MWh	€134.1/MWh
Weighted-Average Grid Export Revenue	€86.9/MWh	€97.3/MWh	€83.8/MWh	€95.4/MWh	€82.7/MWh	€94.1/MWh
Weighted-Average System Revenue	€86.9/MWh	€97.3/MWh	€103.1/MWh	€112.1/MWh	€108.6/MWh	€116.5/MWh

Note: Table B.4 reports rounded export and revenue figures. The €86.9/MWh baseline, and all per-MWh figures in the main text, are computed from unrounded hourly values; the rounded totals in Table B.4 imply approximately €87.1/MWh, the difference arising solely from rounding. Total energy figures exceed the S0 baseline in mining scenarios because DD absorption adds energy throughput that would otherwise be spilled. RESS-supported columns are indicative only and not simulated as discrete scenarios; see Section 3.4. Higher BMU consumption in these columns reflects the two-way CfD structure: in exceedance hours, the generator remits the difference between DAM price and strike price, capping effective export revenue at €100.47/MWh. In 2024, the DAM price exceeded this threshold in 51.5% of settlement hours, lowering the effective opportunity cost of own-supply diversion to mining and increasing BMU activation frequency relative to merchant operation.

Appendix C. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.eneco.2026.109454.

Data availability

The data supporting this study derive from publicly available sources and computational modelling. Hourly wind speed data (100 m hub height) were obtained from *Open-Meteo* (https://open-meteo.com/). Day-Ahead Market prices for 2024 were sourced from SEMO (https://www.sem-o.com/). System statistics were obtained from *EirGrid* reports (https://www.eirgridgroup.com/). Bitcoin price and hashrate data were sourced from blockchain.com (https://www.blockchain.com/). The Excel-based simulation model, containing all input data and scenario calculations used in this study, is provided as supplementary material accompanying this article.

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