



Research Paper

Probabilistic techno-economic assessment of large-scale anaerobic digestion plants for biomethane production: de-risking biomethane futures

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ABSTRACT

This study investigates the economic feasibility and profitability of large-scale biomethane production through anaerobic digestion (AD) at plant capacities of 10, 20, and 40 GWh, using grass silage and cattle slurry as feedstocks. A robust deterministic and probabilistic modelling approach was employed to evaluate essential financial indicators, including Levelized Cost of Biomethane (LCOB), Net Present Value (NPV), Internal Rate of Return (IRR), and Payback Period (PBP). Sensitivity analysis observed at changes in the costs of grass silage ($\pm 30\%$) and biomethane ($\pm 50\%$). A Monte Carlo simulation with 10,000 iterations assessed at uncertainty by figuring out mean values, the chance of a positive NPV, and Conditional Value at Risk (CVaR). The results show that there is a good link between scale and financial performance. The cost of capital expenditures (CAPEX) ranged from €2.9 million for 10 GWh to €7.9 million for 40 GWh. As the scale of the plant grew, the cost of modifications and grid connections went down. The 40 GWh AD plant exhibited the strongest performance, achieving an NPV of approximately €22.2 million, an IRR of 30%, an LCOB of 0.079 €/kWh (\approx €0.79/Nm³), and a payback period of 3.2 years, whereas the 10 GWh plant delivered a lower IRR of 16% and a longer payback period of 6.7 years. A probabilistic investigation confirmed that larger investments are more resilient, with the probability of a positive NPV rising from 81% to 92%.

1. Introduction

Climate change, primarily fueled by greenhouse gas (GHG) emissions, poses a significant global threat, with agriculture contributing 10–12% of these emissions, escalating to 25% when factoring in land-use changes [1–3]. In response, the shift towards low-carbon energy systems is gaining momentum, with bioenergy emerging as a pivotal solution for decarbonizing sectors that are traditionally hard to abate [4–6]. Among these solutions, anaerobic digestion (AD) has proven effective in converting organic waste into renewable biomethane [7–9]. In Europe, biogas production reached over 35 billion cubic meters in 2022, with projections indicating a doubling by 2040. The growth of AD technology, evidenced by approximately 21,322 operational biogas plants across Europe, highlights its potential to meet 30–40% of the EU's gas demand by 2050, contributing at least 1,000 TWh annually and significantly to GHG reduction and sustainability goals [10–12]. This expansion underscores both the technological viability of AD and the effectiveness of supportive EU policies to reduce GHG emissions and promote sustainability [13]. Recent studies have assessed large-scale

anaerobic digestion (AD) and biogas upgrading systems using real-scale data combined with integrated techno-economic and environmental modelling [14–16]. These analyses show that AD-based pathways can deliver substantial decarbonisation benefits when appropriately scaled and system-integrated, while highlighting the importance of plant scale, cost structure, and market conditions in determining economic performance [10,17–21].

However, a significant gap remains in understanding the economic viability of biomethane production under real-world market, policy, and feedstock variability [22]. Conventional techno-economic assessments (TEAs) are largely deterministic and fail to capture uncertainties that strongly influence investment risk and financial performance. This limitation is particularly critical for large-scale biomethane systems operating under agriculture-dominated feedstock conditions, where costs and revenues are shaped by biological variability, feedstock price volatility, and evolving policy frameworks [23].

To address this limitation, probabilistic TEAs incorporating sensitivity and uncertainty analyses are required to enable a more realistic assessment of key economic drivers, downside risks, and investment

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robustness. This need is amplified by agriculture being widely recognised as a “hard-to-abate” sector within the EU, where emission reductions must be achieved alongside food security and farm income stability [1,24,25]. In this policy context, the EU’s Effort Sharing Regulation highlights the urgency for national targets in non-ETS sectors, including agriculture, emphasizing farm income diversification and less emission-intensive practices [11,26,27]. In this context, biomethane provides a scalable energy solution that links agricultural feedstocks with climate mitigation and economic co-benefits.

Within this regulatory and techno-economic framework, Ireland represents a relevant case for country-level analysis. Agriculture is the largest contributor to national greenhouse gas emissions in Ireland, accounting for approximately one-third of the total. Despite strong EU-level climate ambition, deployment of anaerobic digestion technologies in Ireland remains limited, constraining mitigation potential within the agricultural sector. Grasslands cover approximately 37% of Ireland’s land area and underpin livestock production and carbon sequestration; however, prevailing livestock-intensive management practices continue to drive emissions through enteric fermentation and manure management [28].

Biomethane technologies, while promising, often require large-scale deployment to achieve economic viability due to the high capital and operational costs associated with conventional upgrading technologies. This scale dependency poses significant challenges for small-scale biomethane plants, frequently rendering them financially unfeasible [29–31]. Techno-economic assessments play a central role in evaluating project profitability and commonly employ indicators such as net present value (NPV), internal rate of return (IRR), and payback period (PBP) [27,32]. Existing research on anaerobic digestion systems has provided valuable insights into key cost drivers and profitability trends across different plant scales. [10,17,18,20,33]. By integrating sensitivity and scenario-based approaches, probabilistic TEAs enable a comprehensive evaluation of investment risk and economic resilience, supporting informed decision-making by policymakers, developers, and investors. Understanding the economic dynamics of biomethane production at scale is therefore pivotal for shaping effective policies and investment strategies aligned with long-term decarbonisation objectives.

Despite this, biomethane holds significant potential for agricultural decarbonisation, yet evidence of its cost-effectiveness at scale remains limited within current market frameworks [27,34]. Economic viability depends on multiple interacting factors, including feedstock sourcing, digester sizing, upgrading costs, and digestate management, all of which must be carefully optimised to achieve sustainable financial performance [10,17,35–37]. These elements play a pivotal role in determining the overall viability of biomethane systems and require careful optimization to ensure financial sustainability. In addition, limited interdisciplinary research addressing the motivations and decision-making behaviour of potential anaerobic digestion adopters represents a critical knowledge gap that may hinder deployment and increase investment risk in this sector [10,17,33].

Thus, Ireland is selected as the case study due to its surplus agricultural feedstocks, high agricultural emissions, and historically slow biomethane sector development despite significant potential. This makes it an ideal context to assess large-scale AD deployment, focusing on grass silage and cattle slurry as primary feedstocks, with water scrubbing adopted as a cost-effective upgrading technology. Three plant scales of 10 GWh, 20 GWh, and 40 GWh capacity are considered, along with economic viability metrics such as Levelized Cost of Energy (LCOE), Net Present Value (NPV), Internal Rate of Return (IRR), and Payback Period (PBP). These account for capital and operational expenditures associated with feedstock procurement, reactor configuration, biogas upgrading, and digestate management. A market sensitivity assessment is conducted by varying grass silage prices ($\pm 30\%$) and gas selling prices ($\pm 50\%$) to evaluate financial performance and identify critical cost thresholds. Furthermore, a probabilistic uncertainty

analysis using Monte Carlo simulation offers insights into investment risk and quantifies variability in profitability across plant scales, generating outputs such as Conditional Value at Risk (CvaR) and distributions of NPV and IRR to support robust risk assessment. This study not only evaluates the techno-economic feasibility and sensitivity to market drivers but also integrates deterministic and probabilistic methods to enhance understanding of how scale impacts investment certainty and resilience to market fluctuations. This assessment, combining techno-economic analysis, sensitivity analysis, and Monte Carlo simulations, offers a robust decision-support framework. The insights derived from this analysis are directly relevant for policymakers, developers, and investors, as they support evidence-based decision-making, facilitate the strategic deployment of biomethane infrastructure, and contribute to Ireland’s transition toward a low-carbon energy system.

2. Methodology

2.1. Background

Anaerobic digestion (AD) has progressed from an emerging waste-to-energy pathway to a central element of Europe’s renewable gas portfolio. By 2023, the region hosted over 21,000 biogas and biomethane facilities, driven by sustained policy support and technological diffusion, particularly in Germany, the UK, Italy and France. This expansion reflects the growing strategic role of biomethane within the European energy transition and its contribution to energy security and decarbonisation objectives. [10–12]. Ireland’s anaerobic digestion (AD) sector is currently underdeveloped, with only a handful of operational plants and limited biomethane upgrading for gas grid injection. Ranking approximately 20th among the EU-27 in biogas capacity, the country faces numerous technical, economic, infrastructural, and policy-related challenges that impede growth [26,27]. Despite the presence of agricultural feedstocks such as grass silage and cattle slurry, their utilization in AD remains limited. Historically, Ireland has concentrated on small-scale, farm-based AD systems for combined heat and power (CHP), which are economically viable but lack the economies of scale necessary for efficient biomethane production. Larger AD systems encounter logistical hurdles, especially in sourcing feedstock from remote farms. Additionally, previous renewable energy support mechanisms, such as the REFIT schemes, offered lower tariffs than those in other EU nations, reducing the financial attractiveness of biomethane projects [10,26]. In response to the slow growth of AD and the substantial biomethane potential within its agricultural sector, Ireland introduced the National Biomethane Strategy in 2024 [38].

This initiative aims to increase the country’s biomethane production to 5.7 TWh annually by 2030, demonstrating a strong commitment to improving AD infrastructure and expanding biomethane production capabilities.

2.2. Scenario Overview

Based on potential biomethane plant sizes outlined in Ireland’s National Biomethane Strategy, three hypothetical AD plant scenarios are developed: Scenario 1 (10 GWh), Scenario 2 (20 GWh), and Scenario 3 (40 GWh). These scenarios are designed to assess the potential for biomethane production in alignment with Ireland’s national biomethane policy target of 5.7 TWh of energy.

Grass silage (GS) was selected as the primary feedstock for co-digestion in these AD systems due to its high biogas yield potential. It is particularly suitable for sustainable AD feedstock production, requiring lower fertiliser inputs and offering significant environmental benefits [10]. Cattle slurry (CS) from Irish farms provides a valuable complementary feedstock, offering the dual advantages of biogas production and mitigation of fugitive methane emissions associated with slurry storage. According to data from Ireland’s national statistics

Table 1
Generalised assumptions for the techno-economic analysis [10,49].

| Description | Assumptions |
|---|--|
| Annual operating hours [h] | 8,000 |
| Project lifetime [years] | 20 (after construction and start-up) |
| Calculation year | 2025 |
| Discount rate [%] | 6 |
| Depreciation | Straight line over plant life (20 years) |
| Depreciation rate [%] | 5 |
| Debt ratio [%] | 60 |
| Loan period [years] | 10 |
| Interest on debt [%] | 2 |
| Inflation rate (on operational expenditure or OPEX and product pricing) [%] | 2 |
| Year-on-year decrease in production [%] | 2 |

agency, the Central Statistics Office (CSO), and additional data collected from Teagasc, Ireland has 1.51 million dairy cows. With stabilisation in national dairy cow numbers, this ensures consistent slurry availability for AD operations [39,40].

The calculations in this study are based on the fact that cattle in Ireland are housed for only 16 weeks each year, during which cattle manure can be collected [27,39,41,42]. For a total biomethane production target of 5.7 TWh, it was determined that cattle alone should supply at least 50% of the required energy input to meet RED II sustainability criteria for slurry-based biomethane production [43] consistent with national bioenergy sustainability guidance [44]. Consequently, these AD plants utilise a co-digestion strategy with a 50:50 split on an energy contribution basis between GS and CS; differences in specific methane yields result in varying annual feedstock quantities, as reported in Table 4.

Several technologies were considered for the removal of CO₂ from biogas to produce biomethane. This biomethane could either be directly injected into the gas network or, in the case of smaller AD plant sizes, be transported via haulage vehicles or mobile upgrading units [45]. The technologies commonly used for CO₂ removal for industrial scale biomethane plants include water scrubbing, pressure swing adsorption, chemical/amine scrubbing, and membrane separation [46].

In this study, it was assumed that all biogas produced under the defined scenarios would be upgraded to biomethane. Among the various available upgrading technologies, water scrubbing was selected due to its widespread commercial application and offering a high technology readiness level (TRL 9) and proven scalability for large-scale biomethane production [4,47]. The upgrading plant investment costs for the 10–40 GWh biomethane production scenarios considered in this study, based on water scrubbing technology, are summarised in Table S1.

2.3. Economic analysis assumptions

The economic assumptions used in this study are shown in Table 1. These include the annual operating hours, project lifetime, discount rate, debt ratio, loan period, inflation rate, interest on debt and year-on-year decrease in production. It is assumed that biomethane plants will be constructed in one year, followed by six months start-up time. For all the scenarios considered, 20 years is the lifetime of the plant, with 5% straight line depreciation rate with over plant life [10,47]. This study used a discount rate of 6% as a conservative estimate, which is previously applied in similar studies [27,48].

2.4. Deterministic economic analysis

2.4.1. Total capital expenditure

In order to assess the feasibility of biomethane production in Ireland, a financial model was developed and executed. The capital expenditure

Table 2
Operational expenditure [10,33,39].

| Cost Component | Unit Basis | Description / Notes |
|-----------------------|--|---|
| Plant O&M | €/m ³ reactor/year | General operations & maintenance of plant |
| Feedstock procurement | €/ton/year | Cost of purchasing feedstock |
| Digester maintenance | €/m ³ reactor/year | Maintenance of digester system |
| Labour | €/m ³ /year | Labour cost for plant operation |
| Electricity | €/kWh/ton feedstock | Power consumption for AD process |
| Transportation | €/ton.km | Feedstock/digestate transport |
| Admin costs | €/m ³ /year (or €/m ³ gas) | Administrative & overhead expenses |
| Digestate disposal | €/ton/year | Waste/by-product management |

(CAPEX) and operating expenditure (OPEX) costs for each scenario were derived from the data provided by Dennehy et al. (2017), which assessed the economic viability of on-farm co-digestion systems in Ireland [18]. All obtained cost values were updated to the present study's project base year 2025 values using the chemical engineering plant cost index (CEPCI) [50] and CSO price indices [51–53].

The following costs were considered in calculating the total capital expenditure (CAPEX) for each of the three scenarios: Digester civil construction (€/m³), digestate storage lagoon (€/m³), additional site civil cost (€/m³), feedstock reception building (€/ton/d), pasteurizer and heat exchanger cost (€/ton/d), manure pipework and pumps, biogas upgrading plant (€) and grid connection(€). Upgrading plant investment costs (expressed as €/m³/h of biomethane capacity) were obtained from the literature and the corresponding biomethane production capacities for each scenario are presented in Table S1 [54,55]. The total upgrading cost was calculated as the product of the unit investment cost (€/m³/h) and the corresponding biomethane flow rate (m³/h) derived for each scenario. These cost components were added together to compute the subtotal. Additional costs, such as development (5% of subtotal), insurance (4% of subtotal), contingency (10% of subtotal), and engineering (7% of subtotal), were also included in the final total capital expenditure calculation.

2.4.2. Operational expenditure

These OPEX components were calculated for each scenario to estimate the total annual operational costs for the biomethane plant of all three scenarios (see Table 2). The final annual OPEX was derived by summing the costs for each of these factors. For OPEX cost projections, all obtained cost values were updated to the present study's project base year 2025 [33,39].

2.4.3. Financial assumptions

For the present study, a certificate price of €0.098/kWh is considered for financial benefits, based on data obtained from Gas Networks Ireland [33]. Furthermore, gas grid connection grants, covering an average of 70% of total connection costs were included, based on data provided by Gas Networks Ireland 30% of grid connection costs are borne by developer [56,57].

2.4.4. Cost Benefit analysis

To evaluate the economic viability of each scenario, a set of financial indicators was employed. These indicators were designed to capture the payback of CAPEX while accounting for cash flows derived from OPEX, revenue, and the time value of money through a discount rate. The net present value (NPV) of the biogas plant was calculated [49,58] over a 20-year operational lifespan using the following formula:

$$NPV(\text{€}) = \sum_{t=1}^n \frac{R_t - C_t}{(1+r)^t} - C_0 \quad (1)$$

where C_t represents the plant's cash flow in year t , C_0 is Initial investment or cost at time $t = 0$ with a discount rate (r) of 6%. The plant's lifetime (n) was assumed to be 20 years. R_t represents revenue in year t while C_t represents total operating cost in year t (including feedstock and OPEX). CAPEX is the initial capital expenditure.

The internal rate of return (IRR), shown in Eq. 2., is also calculated as a key profitability measure. IRR represents the discount rate at which the NPV becomes zero, signifying the return on investment required for the project to compensate for the reduction in value of the invested capital. IRR is calculated below:

$$0 = \sum_{t=1}^n \frac{NCF}{(1 + IRR)^t} - C_0 \quad (2)$$

where NCF is net cash flow in years t . IRR is determined using the inbuilt IRR function in Microsoft Excel. Payback period, defined as the time required for the NPV to reach zero, is also determined, referring to the number of years it takes to generate enough revenue to repay the initial investment. The discounted payback period makes the same calculation but includes the time value of money.

The levelised cost of biomethane (LCOB) reflects the average cost per unit of energy produced over the plant's lifetime, incorporating CAPEX, OPEX, and fuel/feedstock costs. The LCOB depicts the revenue per unit energy produced that results in an NPV of zero [10,49] as shown in Eq. (3)

$$\text{Levelised Cost Of Biomethane (LCOB)} = \frac{\sum_{t=1}^n \frac{C_t}{(1+r)^t}}{\sum_{t=1}^n \frac{E_t}{(1+r)^t}} \quad (3)$$

where C_t represents the total annual cost in year t (OPEX + feedstock), E_t is the biomethane output (kWh) in year t , r is the discount rate, n is the project lifetime, and $t = 1, 2, \dots, n$ denotes the annual time step, with $t = 1$ corresponding to the first year of plant operation.

2.5. Deterministic sensitivity analysis

A deterministic sensitivity analysis was conducted to evaluate the influence of key economic parameters on project profitability and to identify dominant cost drivers affecting the net present value (NPV), internal rate of return (IRR), and levelised cost of biomethane (LCOB) [10]. Biomethane energy content was assumed to be 10 kWh/Nm³ (lower heating value basis), consistent with standard methane calorific values reported in the literature [59]. Accordingly, biomethane production costs expressed in €/kWh can be directly converted to €/Nm³. Sensitivity ranges were selected to reflect plausible market and policy uncertainty conditions relevant to large-scale biomethane deployment [60].

In particular, the grass silage (feedstock) price was varied by $\pm 30\%$ around the base-case value (€48/ton) to capture uncertainty associated with agricultural input costs, seasonal variability, and supply-chain dynamics [61]. In addition, the biomethane selling price, with a base value of €0.138/kWh (equivalent to €1.38/Nm³ assuming 10 kWh/Nm³), comprising a certificate price of €0.098/kWh and a fixed market price of €0.04/kWh, representative of Western European biomethane markets [62], was varied by $\pm 50\%$ to reflect volatility in renewable gas markets, policy support mechanisms, and certificate price uncertainty. Each parameter was varied individually (one-at-a-time), while all other parameters were held constant at their baseline values, allowing the isolated effect of each variable on economic performance to be quantified.

The results of this sensitivity analysis provide a deterministic assessment of economic robustness and are subsequently used to define the lower and upper bounds for the probabilistic Monte Carlo uncertainty analysis described in Section 2.6.

Table 3

Distributional characteristics of levelised cost (€/kWh) Monte Carlo simulation.

| Parameter | Distribution | Unit | Mean | Std. Dev. | Lower Bound | Upper Bound |
|----------------|--------------|-------|-------|-------------|-------------|-------------|
| Feedstock Cost | Normal | €/ton | 48 | ± 7.2 | 33.6 | 62.4 |
| Gas Price | Normal | €/kWh | 0.138 | ± 0.069 | 0.0345 | 0.207 |

2.6. Probabilistic uncertainty analysis: Monte Carlo simulation

As discussed in Section 2.4.3, LCOB and IRR estimates are traditionally evaluated at a point that does not consider certain technological and market uncertainties. A probabilistic methodology identifies the distribution of potential LCOB or IRR values and, to account for input cost uncertainty in project evaluation, one may choose a point in the calculated probability distribution that corresponds to an LCOB or IRR value likely to occur with an acceptable degree of certainty [32]. To account for real-world market uncertainties, both sensitivity analysis and probabilistic modelling were conducted.

To quantify the uncertainty associated with project profitability and assess the probabilistic outcomes of biomethane energy investments, statistical simulation methods, particularly Monte Carlo simulation, are considered the most appropriate approach [32,47]. Uncertainty analysis estimates ambiguity in a calculation methodology, enabling a comprehensive evaluation of financial variability and associated risks. The probabilistic modelling for uncertainty analysis is conducted via Monte Carlo simulation using a bounded normal probability distribution, ensuring the variation stays within the provided range. 10,000 iterations are generated for each plant scale (10, 20, and 40 GWh). Input values are sampled around a defined mean with a specific standard deviation but constrained within realistic minimum and maximum bounds to avoid extreme outliers.

The randomly drawn values follow a normal distribution centred at mean with a standard deviation of ± 7.2 for feedstock and ± 0.03 for gas price but are restricted between their defined lower and upper bounds (see Table 3). This method enhances the robust and bounded simulation while maintaining statistical variability, enabling the realistic estimation of mean NPV, IRR, LCOB, and downside risk measures like Conditional Value at Risk (CVaR) [63]. CVaR augments this analysis by considering the entire tail of the profitability/cost distribution. CVaR averages values within the tail to measure the expected value, conditional on achieving a value beyond the β Value at Risk [63]. The formula to calculate the CVaR from a given probability density function is outlined in detail in [32]. We adapt this formula to provide an index of uncertainty for both IRR and LCOB.

3. Results

3.1. Technical analysis

To assess the technical feasibility of biomethane production, three AD plant capacities were considered: 10 GWh/year (Scenario 1), 20 GWh/year (Scenario 2), and 40 GWh/year (Scenario 3). The corresponding feedstock demands for each scenario, based on energy yields, are detailed in Table 4.

These findings underscore the importance of GS as a complementary feedstock, particularly in light of Ireland's abundant surplus. The integration of GS not only supports consistent biogas yields but also aligns with broader national objectives related to agricultural circularity and renewable energy expansion.

3.2. Economic assessment

The economic analysis includes evaluating the capital costs (CAPEX), the operational costs (OPEX), and other essential parameters that

Table 4

Technical details of all three scenarios.

| Scenario | Plant Capacity (GWh) | Energy mix (CS:GS) | Cattle Slurry (CS) (tonnes/year) | Grass Silage (GS) (tonnes/year) | Biogas (m ³ /year) | Size of each digester (m ³) | Hydraulic Retention Time (HRT) (Days) | AD plant capacity (Tonnes/day) |
|-------------------|----------------------|--------------------|----------------------------------|---------------------------------|-------------------------------|---|---------------------------------------|--------------------------------|
| Scenario 1 | 10 | 50:50 | 8730 | 5980 | 1,851,852 | 1701(1 no.) | 30 | 40 |
| Scenario 2 | 20 | 50:50 | 26,455 | 11,961 | 3,703,704 | 4141 (1 no.) | 30 | 105 |
| Scenario 3 | 40 | 50:50 | 52,910 | 23,923 | 7,407,407 | 4141(2 no.s) | 30 | 211 |

Note: Energy yields assumed as 0.836 MWh/ton for grass silage and 0.122 MWh/ton for cattle slurry, based on National Biomethane Strategy Ireland in 2024 [38].

Table 5

Techno economic analysis includes evaluating the capital costs (CAPEX), and operational costs (OPEX),

| Parameter | Price/cost used | Equation used | 10 GWh | 20 GWh | 40 GWh |
|---|---|---|-----------------------|-----------------------|-------------------------|
| | | | Euros (€) | Euros (€) | Euros (€) |
| Digester construction | €265/m ³ reactor | Cost * digester size (m ³) | 451,366 | 1,098,941 | 2,197,882 |
| Digestate storage lagoon | €41/m ³ reactor | Cost * digester size (m ³) | 69,962 | 170,336 | 340,672 |
| Additional site civil work cost | €183/m ³ reactor | Cost * digester size (m ³) | 311,443 | 758,269 | 1,516,538 |
| Feedstock reception | € 1,704/ton co-substrate/d | Cost * grass silage fed (t/d) | 27,924 | 55,848 | 111,695 |
| Pasteurization | € 2,591/ton co-substrate/d | Cost * slurry fed (t/d) | 62,009 | 187,906 | 357,812 |
| Manure pipework and pumps | € 1.15/m ³ | Cost * digester size (m ³) | 1950 | 3246 | 6493 |
| Upgrading plant | €/ (m ³ /h) of biomethane | Cost * Biogas flow (m ³ /h) | 697,615 (5500*127) | 887,874 (3500*254) | 1,100,964 (2170*507) |
| Connection to gas grid | €2,284,153 | 0.30*2,284,153 | 685,245 | 685,245 | 685,245 |
| Development costs | 5% of CAPEX | 0.05 * ∑ CAPEX | 115,376 | 192,458 | 316,915 |
| Insurance | 4% of CAPEX | 0.04 * ∑ CAPEX | 92,301 | 153,967 | 253,532 |
| Contingency | 10% of CAPEX | 0.10 * ∑ CAPEX | 230,751 | 384,917 | 633,830 |
| Engineering | 7% of CAPEX | 0.07 * ∑ CAPEX | 161,526 | 269,442 | 443,681 |
| Physical CAPEX | Total CAPEX – Development costs – Insurance – Contingency – Engineering | | 2,307,514 | 3,849,166 | 6,338,303 |
| Total Capex | | | 2,907,468 | 4,849,949 | 7,986,261 |
| Plant operation and maintenance (O + M) | € 4.83/m ³ reactor | Cost * digester size (m ³) | 8214 | 20,000 | 39,999 |
| Digester maintenance | € 3.62/m ³ reactor | Cost * digester size (m ³) | 6157 | 14,989 | 29,979 |
| Upgrading plant maintenance | € 0.01/m ³ biogas | Cost * biogas available for upgrading (m ³) | 18,519 | 37,037 | 74,074 |
| Labour | € 14.18/m ³ reactor | Cost * digester size (m ³) | 24,113 | 58,707 | 117,414 |
| Electricity | €0.13/kWh | Cost * electricity demand (kWh) | 691 | 1805 | 3610 |
| Admin cost | | | 35,000 | 35,000 | 35,000 |
| Feedstock transport | €0.13/ton.km | Cost * feedstock quantity (ton) * distance (km) | 19,124 | 49,942 | 99,884 |
| Digestate transport disposal | €0.13/ton.km | Cost * digestate quantity (ton) * distance (km) | 26,899 | 65,492 | 130,984 |
| Total OPEX | | | 138,717 | 282,971 | 530,943 |
| AD silage production | €48/ton DM | Cost * AD silage needed (t DM) | 287,081 | 574,162.7 | 1,148,325.4 |
| Income from biomethane | €0.04/kWh (market price) €0.098/kWh (certificate price) | (Market price + certificate price) * biomethane produced (m ³ /year) | | | |

measure profitability. Table 5 shows the sizing and costing of all unit operations considered in three scenarios, dividing the scenarios in terms of energy production capacity (GWh).

The CAPEX was assessed to be €2.9 million, €4.8 million, and 7.9 million, corresponding to plant capacities of 10 GWh, 20 GWh, and 40 GWh, respectively. In this study, development costs (5% of the subtotal), insurance (4% of the subtotal), contingency (10% of the subtotal), and engineering costs (7% of the subtotal) were incorporated as key contributors to the total CAPEX of the biomethane plant. Other major cost components such as digester construction and grid connection, accounted for approximately 40% of the total CAPEX for the 10 GWh plant, decreasing to 35% for the 40 GWh facility. This trend suggests that as plant capacity increases, the relative contribution of these costs to overall CAPEX declines, likely due to economies of scale.

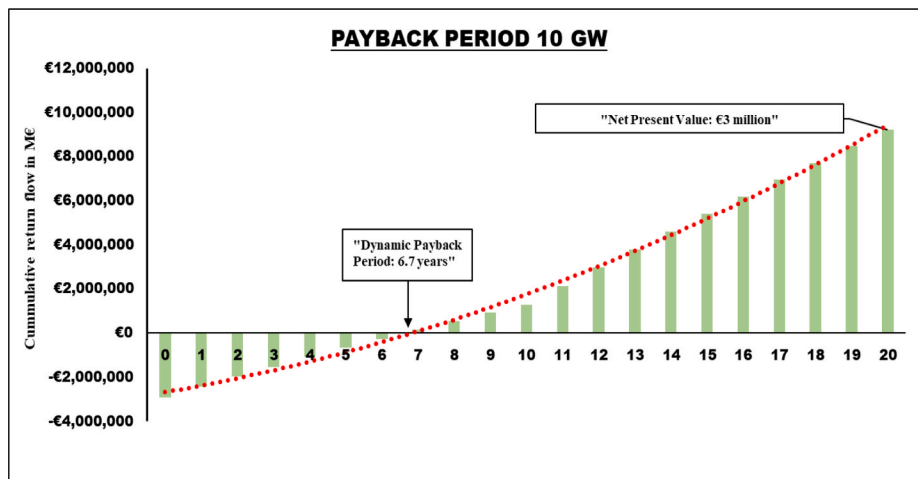
As the system size increases, the cost of grid connection represents a smaller proportion of the total CAPEX, declining from 14.6% for the 10 GWh system to 5.4% for the larger 40 GWh facility. This trend aligns with the findings of Bose et al. (2022), who reported that as system size increases, the grid connection cost becomes a less significant component

of CAPEX, falling from 19% in smaller-scale facilities to 10% in medium-scale plants [49]. Water scrubbing is considered the upgrading technology across all scenarios. The calculated upgrading plant investment costs are €0.69 million, €0.88 million, and €1.10 million for the 10, 20, and 40 GWh scenarios, respectively (Table S1). Biogas upgrading represents 24%, 18%, and 14% of total CAPEX in the 10, 20, and 40 GWh cases, respectively.

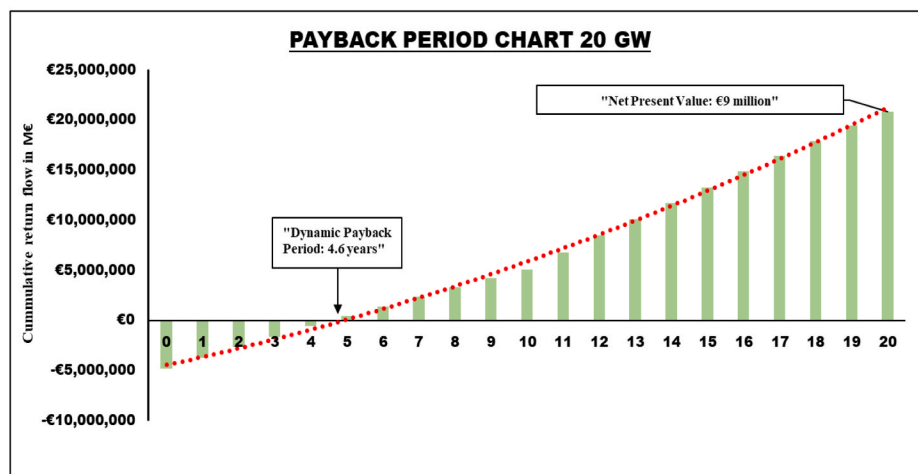
The OPEX costs are assessed to be € 3.4, €7, €13.2 million corresponding to plant capacities of 10 GWh, 20 GWh, and 40 GWh, respectively. When accounting for feedstock procurement costs within the operational costs, biogas upgrading constituted 43% of the total OPEX in Scenario 1, 44% in Scenario 2, and 45% in Scenario 3. Likewise, when considering feedstock procurement costs as part of the total OPEX, feedstock accounted for 46% of the total OPEX in Scenario 1, 47% in Scenario 2, and 49% in Scenario 3.

3.3. Profitability Analysis/Cost-Benefit analysis

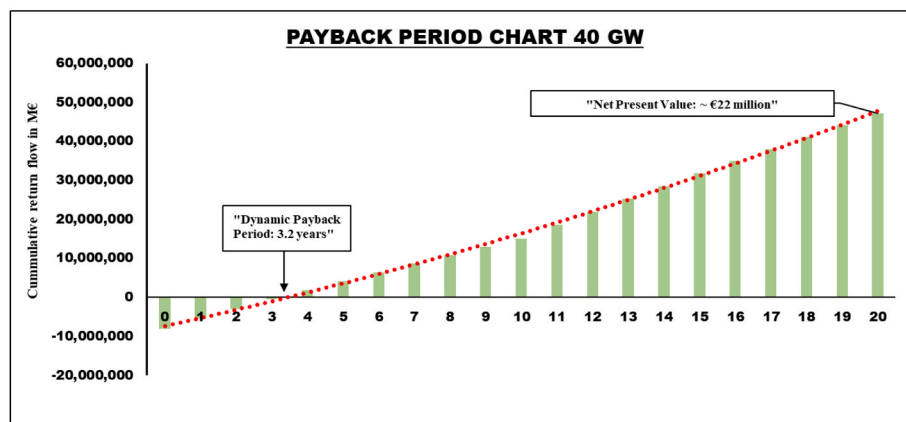
The Net Present Value (NPV), Internal Rate of Return (IRR), and



(a)



(b)



(c)

Fig. 1. (a-c) Cash Flow analysis for (a) 10 GWh plant, (b) 20 GWh plant, (c) 40 GWh plant.

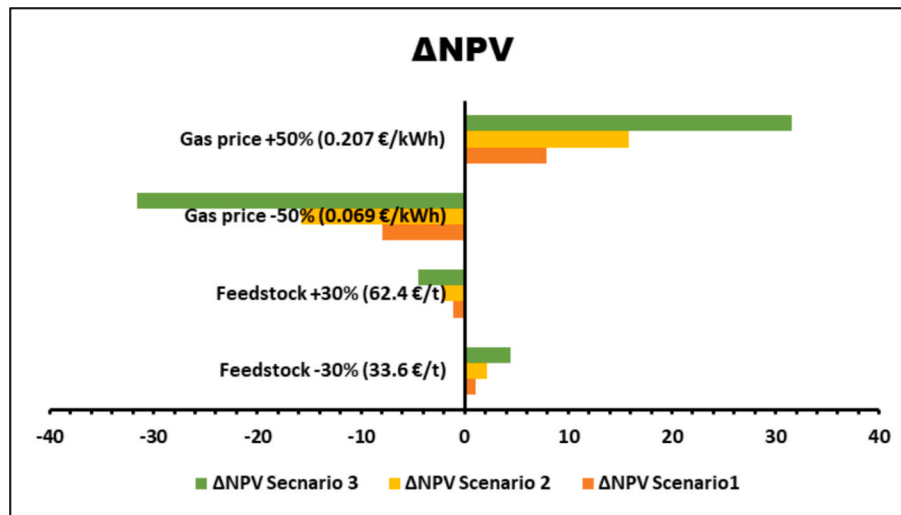


Fig. 2. Change in net present value (Δ NPV) under varying feedstock costs (\pm 30%) and gas selling prices (\pm 50%) for 10, 20, and 40 GWh biomethane plants.

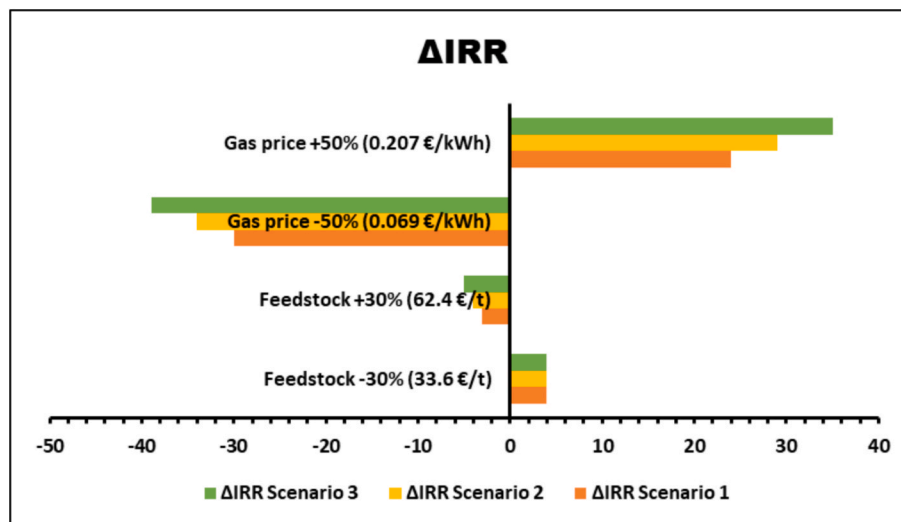


Fig. 3. Change in internal rate of return (Δ IRR) under varying feedstock costs (\pm 30%) and gas selling prices (\pm 50%) for 10, 20, and 40 GWh biomethane plants.

Payback Period (PBP) were calculated for each scenario to assess economic feasibility. All scenarios showed positive NPV values of approximately €3million, €9million, and €22 million respectively, indicating financial viability. Corresponding IRRs were 16% for Scenario 1, 22% for Scenario 2, and 30% for Scenario 3, with payback periods of 6.7, 4.6, and 3.2 years, respectively (see Fig. 1). All scenarios therefore maintained a PBP of less than 10 years.

3.4. Sensitivity analysis

A sensitivity analysis was conducted to evaluate the robustness of the financial performance of biomethane plants by examining the most influential factors affecting overall profitability. In alignment with previous studies by Beusang et al. (2021) and Padi et al. (2023), the sensitivity analysis shows that the GS (feedstock) price and the biomethane certificate price emerged as the most influential parameters affecting NPV and IRR variations [10,34]. A thorough sensitivity analysis was performed to assess the impact of critical market variables feedstock cost (GS at €48/ton) and biomethane selling price (€0.138/kWh) on economic performance metrics, specifically NPV, IRR, and LCOB. Variability was established by implementing a \pm 30% alteration in feedstock price and a \pm 50% alteration in biomethane selling price,

mirroring authentic market variations.

The resulting effects on project profitability are measured by observing changes in NPV, IRR, and LCOB for each scenario, as shown in illustrated in Figs. 2-4. Biomethane price had the greatest impact on NPV and IRR, although feedstock cost had a greater influence on LCOB. At the baseline grass silage price of €48/ton, the NPV for operational costs for 10 GWh, 20 GWh, and 40 GWh plants were €5.8 million, €13.1 million, and €29.3 million, respectively, with IRRs of 16%, 22%, and 31%. A 30% reduction in feedstock price (to €33.60/ton) enhanced NPV by €4.4 million, €2.2 million, and €1.1 million, and elevated IRR by 4% for 40 GWh, 20 GWh, and 10 GWh plants respectively. A 30% rise in feedstock cost (to €62.40/ton) correspondingly diminished NPV and IRR by virtually identical margins.

A 50% escalation in biomethane pricing (to €0.207/kWh) yielded significant NPV enhancements of €31.6 million, €15.8 million, and €7.9 million, alongside IRR increases from 35%, 29%, and 24% for plants generating 40 GWh, 20 GWh, and 10 GWh respectively. A 50% reduction (to €0.069/kWh) resulted in a deterioration of NPV of €31.6 million, €15.8 million, and €7.9 million and a decrease in IRR by 39%, 34% and 30% for the corresponding plant sizes. In contrast to gas prices, fluctuations in feedstock costs exerted a more immediate influence on LCOB, with a 30% increase resulting in a €0.012/kWh rise and a 30% decrease

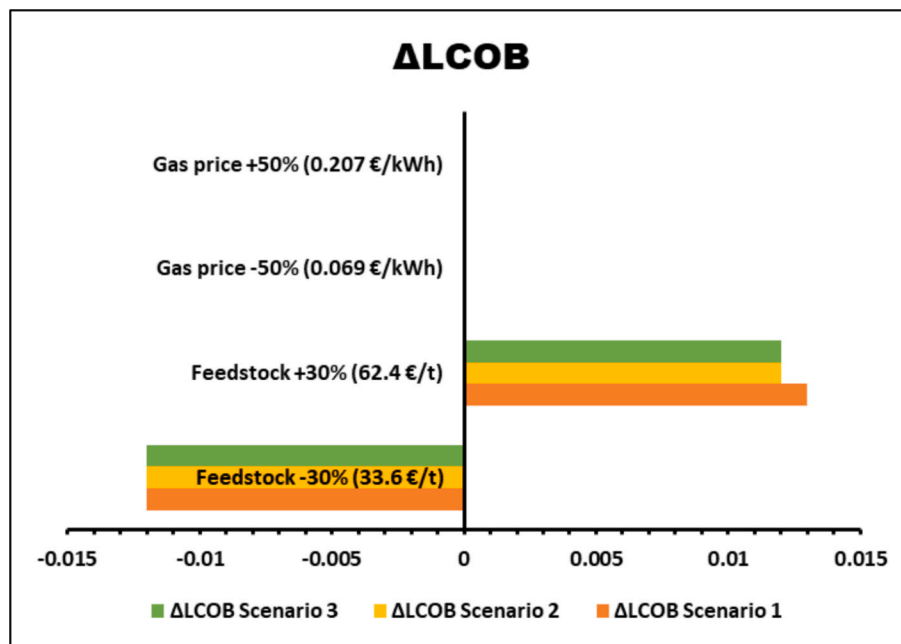


Fig. 4. Change in levelised cost of biomethane (Δ LCOB) under varying feedstock costs ($\pm 30\%$) and gas selling prices ($\pm 50\%$) for 10, 20, and 40 GWh biomethane plants.

Table 6

NPVs from 10,000 Monte Carlo simulations with $\pm 50\%$ gas price and $\pm 30\%$ feedstock uncertainty.

| Plant Size | CAPEX (€million) | Mean NPV (€million) | Range NPV (€million) | Probability NPV > 0 |
|------------|------------------|---------------------|----------------------|---------------------|
| 10 GWh | 2.9 | 3.5 | -5.6 to 12.6 | 81% |
| 20 GWh | 4.8 | 9.2 | -9.1 to 27.2 | 87% |
| 40 GWh | 7.9 | 22.2 | 13.9 to 58.7 | 92% |

Note: probability NPV > 0 indicates positive outcomes.

yielding a comparable reduction. The specific OPEX (€/ton) also varied with changes in feedstock. At 33.6 €/ton and 62.4 €/ton, particular OPEX varied from €0.7 to €0.4 for all plant sizes respectively comparable to a cited figure of €62/ton for a 105 kton/year facility by Rajendran et al. (2019) [47]. Similar trends have been identified by Tisocco et al. (2025) and Andrés Martínez et al. (2025), who reported that feedstock price and plant scale are dominant determinants of operational expenditure in anaerobic digestion systems [19,64]. In line with these studies, our findings confirm that economies of scale contribute to improved cost efficiency per unit output, while feedstock remains the most influential variable driving OPEX variability.

3.5. Uncertainty analysis using probabilistic modelling: Monte Carlo simulations

To evaluate the uncertainty in project outcomes due to variability in key economic parameters, a Monte Carlo simulation was conducted using the sensitivity analysis ranges for feedstock cost and gas selling price. A total of 10,000 random values were generated for each parameter within their defined lower and upper bounds; €33.60/ton to €62.40/ton for feedstock cost using base value of €48/ton with $\pm 30\%$ variation, and €0.069/kWh to €0.207/kWh for gas selling price using base value as €0.138/kWh with $\pm 50\%$ variation.

In this study, the mean NPV values obtained from 10,000 Monte Carlo simulations, applying a 6% discount rate and accounting for \pm

Table 7

Distributional characteristics of internal rate of return simulations.

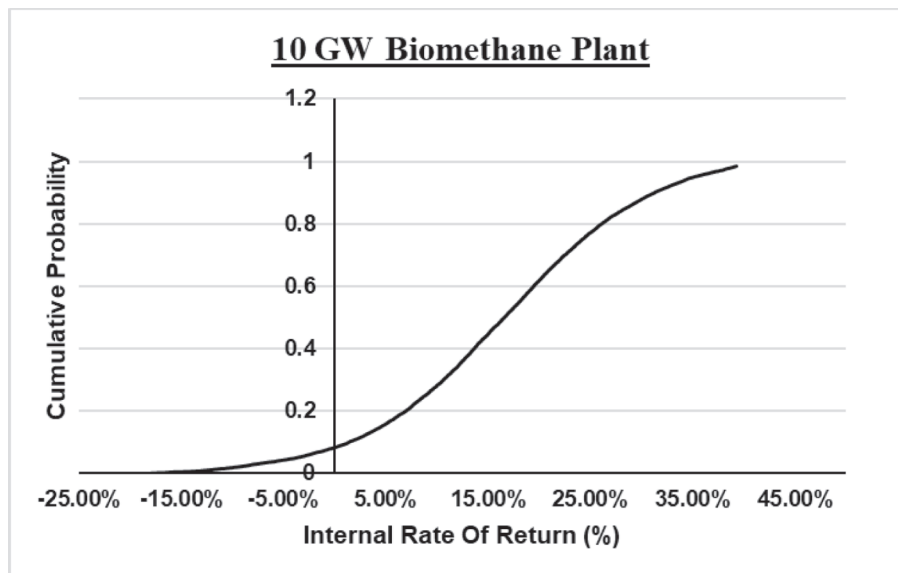
| Plant Size | Minimum | Mean | Maximum | CVaR5 | Mean-CVaR5 | Probability IRR > 0 |
|------------|---------|------|---------|-------|------------|---------------------|
| 10 GWh | -20% | 16% | 43% | -9% | 26% | 84% |
| 20 GWh | -21% | 22% | 54% | -7% | 30% | 89% |
| 40 GWh | -19% | 30% | 70% | -5% | 36% | 91% |

50% uncertainty in gas price and $\pm 30\%$ in feedstock cost was approximately €3 million, €9 million, and €22.2 million for 10, 20, and 40 GWh plants respectively. As shown in Table 6, the probability of achieving a positive NPV (i.e., NPV > 0) increases through the plant size, from 81% for the 10 GWh plant to 92% for the 40 GWh plant. The probability where NPV > 0 indicates the proportion of simulations yielding financially viable outcomes.

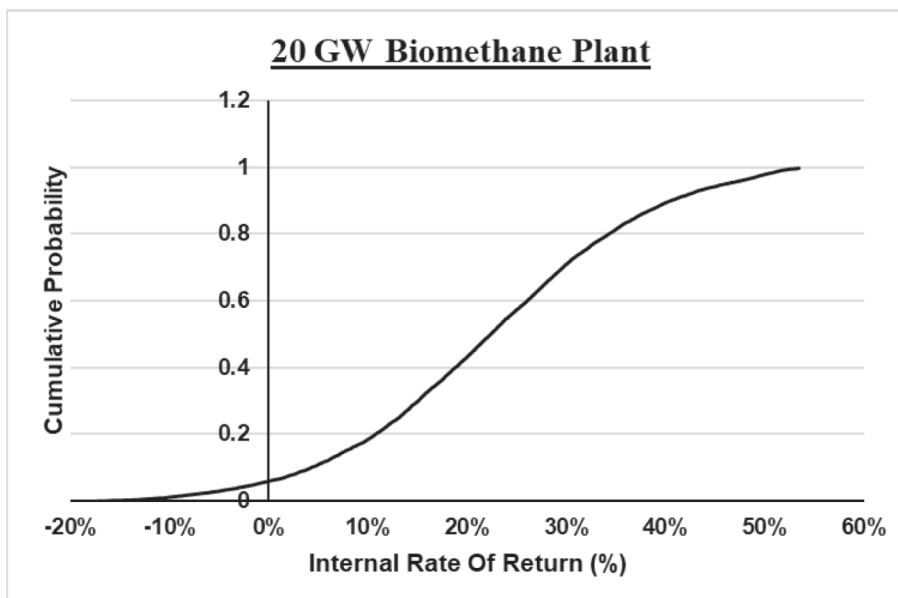
3.5.1. Internal rate of return

In the probabilistic analysis, IRR demonstrated a consistent upward trend with increasing plant capacity, underscoring the economic advantage associated with larger-scale deployment. The mean IRR values for the 10 GWh, 20 GWh, and 40 GWh plants, based on simulation results, were 16%, 22%, and 31% respectively, as shown in Table 7. However, the IRR distributions also exhibited considerable variability, with minimum values ranging between -20% and -29% depending on plant size. To quantify downside risk, Conditional Value at Risk (CVaR₅) at the 5th percentile was calculated, reflecting the average IRR within the lowest-performing 5% of simulations. The CVaR₅ values were -9%, -7%, and -5% for the 10, 20, and 40 GWh plants, respectively. These negative values indicate that under adverse conditions, project returns could decline significantly. This risk-informed perspective is vital for stakeholders assessing project feasibility under real-world uncertainties.

To assess the variability in investment performance, Fig. 5(a-c) presents the cumulative distribution functions (CDFs) of the IRR derived from 10,000 Monte Carlo simulations for 10, 20, and 40 GWh plant capacities under worst-case assumptions. The distributions demonstrate that as plant scale increases, the IRR values become more concentrated



(a)



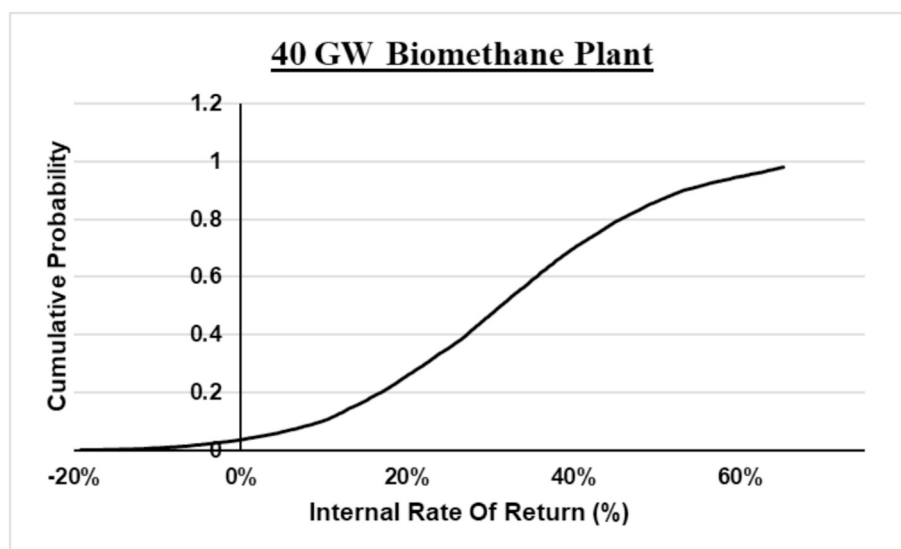
(b)

Fig. 5. Cumulative probability of internal rate of return (IRR) derived from 10,000 simulation runs for plant sizes (a)10 GWh, (b) 20 GWh and (c) 40 GWh.

around the mean, reflecting reduced relative uncertainty. Conversely, smaller-scale plants exhibit wider IRR dispersion, indicating greater sensitivity to input variability.

Fig. 5 illustrates that the IRR distributions become narrower and steeper with increasing plant size, indicating greater profitability stability for larger-scale installations. A higher proportion of IRR values

exceed conventional investment benchmarks (10–15%) in the 20 and 40 GWh scenarios. These results align with findings by Farrell et al. (2015), who observed a comparable scale effect on financial performance for Wave Energy Conversion (WEC) device installations, where larger systems demonstrated reduced variability and enhanced economic viability [32].



(c)

Fig. 5. (continued).

Table 8

Distributional characteristics of levelised cost of biomethane (LCOB) plant simulations.

| Plant Size | Minimum | Mean | Maximum | Coefficient of Variation | CVaR ₉₅ |
|------------|---------|-------|---------|--------------------------|--------------------|
| 10 GWh | 0.077 | 0.089 | 0.102 | 0.065 | 0.101 |
| 20 GWh | 0.073 | 0.085 | 0.097 | 0.068 | 0.097 |
| 40GWh | 0.067 | 0.079 | 0.092 | 0.073 | 0.091 |

3.5.2. Levelised cost of biomethane (LCOB) and Cost-Risk insights

Across all plant scales, LCOB demonstrated a decreasing trend of €0.089/kWh (\approx €0.89/Nm³) for 10 GWh, €0.085/kWh for 20 GWh, and €0.079/kWh for 40 GWh reflecting economies of scale as fixed costs are spread over greater energy output. However, LCOB remains highly sensitive to parameters like feedstock cost, as confirmed in sensitivity analyses, underscoring its relevance in both deterministic and probabilistic evaluations.

To capture extreme cost scenarios, CVaR at the 95th percentile (CVaR₉₅) was used. This metric reflects the average of the worst 5% of LCOB outcomes, representing cost risk under difficult conditions such as raised feedstock prices or low gas selling prices. The CVaR₉₅ values for the 10, 20, and 40 GWh plants were €0.101/kWh, €0.097€/kWh, and €0.091/kWh respectively, each above the mean, indicating potential upward unpredictability in costs. The difference between mean LCOB and CVaR₉₅ (Mean - CVaR₉₅) narrowed with plant size, suggesting greater cost stability and resilience in larger plants. The distribution table demonstrating the result of LCOB for different plant sizes is shown in Table 8 with constant coefficient of variation of 0.065, 0.068 and 0.073 for 10, 20, 40 GWh plants across all plant sizes, indicating low relative variability in production cost estimate over 10,000 iterations. Larger plants show slightly lower mean LCOB, reflecting better economies of scale and improved production efficiency.

Cumulative probability curves for LCOB are shown in Fig. 6a-6c. Flatter curves are seen for smaller plants with sharper rises observed for larger ones. The 40 GWh curve is steeper and narrower than those seen for smaller plants, indicating greater cost stability. The coefficient of variation remains lowest for 40 GWh (0.073), demonstrating reduced variability in production cost. The CVaR₉₅ values highlight the potential

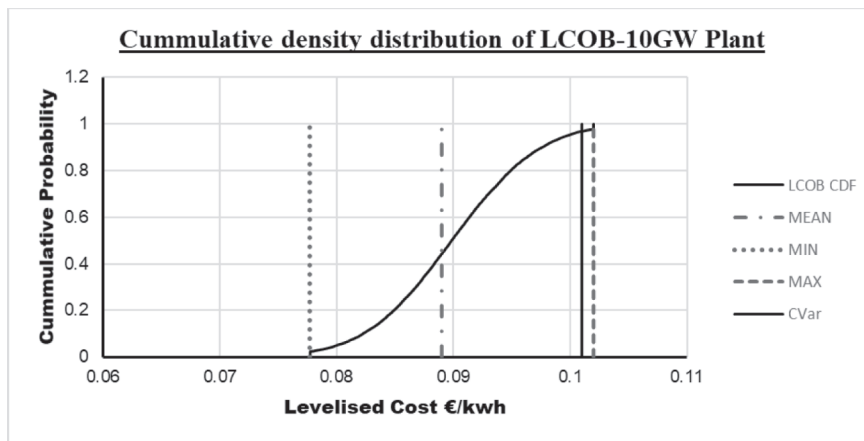
for high-cost outliers under uncertainty, while the consistently low coefficient of variation of \sim 0.07 across all plant scales indicates stable cost predictions. This confirms that larger biomethane plants are not only more cost-efficient on average but also more robust to cost uncertainty, highlighting the importance of scale in project design. These insights are crucial for policymakers and investors when evaluating cost maintenance levels and breakeven thresholds.

4. Discussion and Conclusions

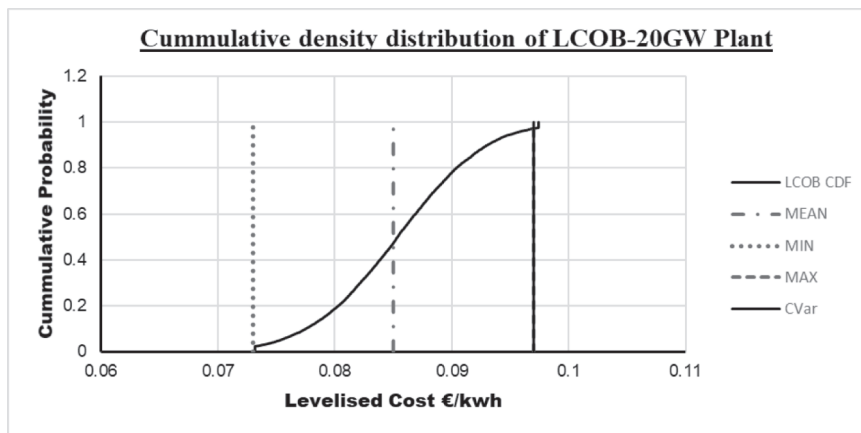
This study presents a comprehensive techno-economic, sensitivity, and uncertainty assessment of three biomethane plant configurations (10, 20, and 40 GWh) co-digesting grass silage and cattle slurry in alignment with Ireland's national biomethane target of 5.7 TWh. Deterministic and probabilistic models were applied to evaluate key financial indicators Net Present Value (NPV), Internal Rate of Return (IRR), Levelised Cost of Biomethane (LCOB), and Payback Period (PBP) under realistic market uncertainties. Sensitivity analysis was conducted by varying grass silage price (\pm 30%) and biomethane selling price (\pm 50%) to identify critical cost thresholds and assess overall investment resilience.

The capital investment (CAPEX) across the three plant scales ranged from €2.9 million (10 GWh) to €7.9 million (40 GWh). Digester construction and grid connection accounted for about 39% of total CAPEX in the smallest configuration, declining to 36% at 40 GWh, reflecting the influence of economies of scale. The biogas upgrading via water scrubbing represented a progressively smaller fraction of total CAPEX, decreasing from 24% to 14% as plant capacity increased from 10 to 40 GWh. The decreasing CAPEX share with increasing plant capacity reflects scale effects commonly reported for biomethane upgrading systems where higher throughput reduces specific investment costs per unit of output [54,55,65]. This challenge is compounded in Ireland due to a relatively underdeveloped gas grid infrastructure, which increases connection costs and constrained network access [43,45,65].

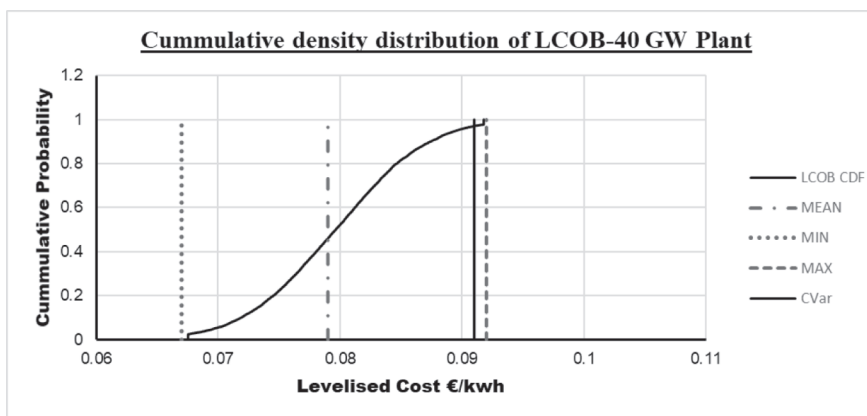
Operating expenditure (OPEX) was estimated at €3.4 million, €7 million, and €13.2 million for the 10, 20, and 40 GWh scenarios, respectively. Feedstock and upgrading dominated total operating costs, together contributing 43–49%. Varying feedstock price by \pm 30% around the base cost of €48/ton altered OPEX by approximately 1.03



(a)



(b)



(c)

Fig. 6. Cumulative distribution of the levelised cost of biomethane (LCOB) from 10,000 simulations across (a)10 GWh, (b) 20 GWh and (c) 40 GWh plants.

times, in agreement with Padi et al. (2024) [10]. The results confirm that while overall costs rise with plant capacity, specific OPEX decreases, evidencing strong scale-related efficiencies.

Financial analysis demonstrated that larger plants significantly outperform smaller systems in all major indicators. The 40 GWh plant achieved the highest NPV (€22.2 million), IRR (31%), lowest LCOB (€0.079/kWh equivalent to €0.79/Nm³), and shortest PBP (3.2 years), while the 10 GWh plant exhibited an IRR of 16% and PBP of 6.7 years, reflecting higher exposure to cost fluctuations. The strong positive correlation between plant capacity and profitability metrics (NPV, IRR, and PBP) highlights the benefits of economies of scale, operational efficiencies, and better resource utilisation. These findings align with previous research by Dennehy et al. (2017), O'Shea et al. (2022), Huerta et al. (2023), Padi et al. (2023), and Tissoco et al. (2025), which reported PBPs of 5–10 years for comparable industrial-scale AD systems [10,17,18,66].

Sensitivity analysis revealed that the biomethane selling price exerts the strongest influence on profitability, primarily affecting NPV and IRR, while feedstock cost has a greater impact on LCOB and overall production efficiency. These results are consistent with Li et al. (2020), who showed that the net present value (NPV) of biomethane projects can vary by more than 80% under a $\pm 20\%$ change in biomethane price [67]. Similarly, Tisocco et al. (2025) identified biomethane price uncertainty as a critical determinant of investment viability and economic performance [60]. The pronounced sensitivity of NPV in this study is attributed to biomethane being the sole revenue stream, unlike models incorporating digestate valorisation or carbon-capture revenues [47]. While both factors affect financial performance, biomethane price remains the principal determinant of profitability, whereas feedstock cost mainly influences production cost efficiency. Furthermore, fluctuations in gas and feedstock prices showed limited impact on required incentive levels, suggesting that structural and policy factors especially stable biomethane certificate pricing are more decisive in sustaining investor confidence.

Probabilistic modelling using Monte Carlo simulations provided additional insight into financial risk and uncertainty. The mean NPVs for the 10, 20, and 40 GWh plants were approximately €3 million, €9 million, and € 22.2 million, respectively, with the probability of achieving positive NPV increasing from 81% to 92% as scale expanded. The Conditional Value at Risk (CVaR₅) for IRR ranged from -9% to -5% , while the CVaR₉₅ for LCOB varied between €0.101/kWh and €0.091/kWh, indicating decreasing cost volatility and improved risk resilience for larger-scale systems. These findings are consistent with uncertainty ranges reported by Farrell et al. (2015), Dennehy et al. (2017), and Tisocco et al. (2025) [18,19,32,33]. The observed reduction in LCOB with increasing scale further supports the existence of significant cost-efficiency gains and validates the robustness of the applied probabilistic framework.

Overall, this integrated analysis reaffirms that large-scale AD systems exhibit stronger financial performance, lower cost volatility, and greater risk resilience, making them the most viable pathway for Ireland's biomethane expansion. Larger facilities deliver higher returns, shorter payback periods, and reduced financial risk, emphasising the strategic need for industrial-scale deployment supported by stable market and policy mechanisms. The 40 GWh configuration represents the most favourable case, combining strong financial performance with cost-effective upgrading via water scrubbing technology. However, challenges related to planning permission and social acceptance particularly for large-scale biogas facilities which may impede project implementation. Public opposition, local environmental concerns, and delays in regulatory approval processes could constrain the pace of infrastructure deployment, ultimately limiting the ability to meet national biomethane and renewable energy targets within the intended timelines.

Future research should extend this work through comparative assessments of alternative upgrading technologies, the valorisation of biological CO₂ as an additional revenue stream via carbon credit markets,

and the development of comprehensive digestate management strategies to maximise both environmental and economic gains. Incorporating policy-incentive modelling and life-cycle environmental assessment (LCA) will further enhance understanding of trade-offs between financial and sustainability outcomes. Together, these advancements will reinforce the economic resilience and environmental integrity of Ireland's emerging biomethane sector, supporting a broader transition toward a low-carbon, circular bioeconomy.

CRedit authorship contribution statement

Shivali Sahota: Writing – original draft, Visualization, Validation, Software, Methodology, Investigation, Conceptualization. **Cathal Geoghegan:** Writing – review & editing, Supervision, Investigation, Formal analysis. **Cathal O'Donoghue:** Writing – review & editing, Visualization, Validation, Supervision, Software, Methodology, Data curation, Conceptualization.

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.

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Appendix A. Supplementary material

Supplementary data to this article can be found online at <https://doi.org/10.1016/j.enconman.2026.121316>.

Data availability

Data will be made available on request.

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