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A Techno-Economic Study of a Net-Zero Renewable Energy Supply for a Farm

Adam Crilly[1], Yaodong Wang[1*], Ye Huang[2]

1 Department of Engineering, University of Durham, Durham, DH1 3LE, United Kingdom

2 Belfast School of Architecture and the Built Environment, Ulster University, Newtownabbey, Co. Antrim, BT37 0QB, UK
(*Corresponding Author: yaodong.wang@durham.ac.uk)

ABSTRACT

This study investigated utilising on-site organic waste from a large-scale dairy farm to provide sustainable electricity and heat. The 600-acre site required 65.2 kWe (electricity) and 9.54 kWth (heat). ECLIPSE software was used to simulate anaerobic digestion (AD) of livestock waste, wheat straw, and barley straw to supply biogas to a cogeneration system. AD produced sufficient biogas to meet all electrical and heating demands from a 100 kWe CHP system, alongside a biogas storage option. The study revealed that a maximum production of 1 MWe can be achieved using four 250 kWe units. Simulations of amine absorption carbon capture demonstrated that 85.1% of the CO_2 could be removed from the CHP flue gases. Annual CO_2 emissions are calculated by displacing current farm emissions, reducing grid usage, and implementing CCS. This results in a reduction of 117 tCO_2e/year, 1692 tCO_2e/year, and 6158 tCO_2e/year for the 100 kWe, 1 MWe, and 1 MWe with CCS systems respectively. Economic analysis shows that the levelised cost of energy for the 100 kWe and 1 MWe options were £60.41/MWh and £47.34/MWh respectively for a lifetime of 20 years. The respective payback period ranges were calculated to be 1.9-4.4 years and 3.5-10.8 years.

Keywords: Dairy farm, Cogeneration, Biofuel, Energy Storage, Carbon Capture and Storage.

NONMENCLATURE

Abbreviations	
AD	Anaerobic Digestion
APEN	Applied Energy
CCS	Carbon Capture and Storage
GHG	Greenhouse Gas
LCOE	Levelised Cost of Energy
LHV	Lower Heating Value

1. INTRODUCTION

Within the UK, the agriculture sector contributes 11% (44.8 $MtCO_2e$) of the total GHG emissions. Nitrous oxide (N_2O), methane (CH_4), and carbon dioxide (CO_2) are the primary gases captured within this statistic.

Biomass is organic matter which is derived from plants. When biomass is used in combustion, the carbon reacts with oxygen in the air to produce carbon dioxide. Under complete combustion of biomass, the CO_2 released into the atmosphere is equal to the CO_2 consumed by plants within the growing stage. This forms the carbon cycle in which there are no net emissions of CO_2 into the atmosphere [1].

Anaerobic digestion (AD) is a natural process by which organic materials are converted into useful products by microorganisms in the absence of oxygen. This process is carried out within an anaerobic digester. A biogas product is released which contains CH_4, CO_2, and other contaminating gases. The solid residue, digestate, remains within the anaerobic digester which can then be used as organic fertiliser [2].

Combined heat and power (CHP) systems, also known as cogeneration, generate electricity and useful heat [3]. Energy storage methods are required for power systems to improve power quality, reliability, and in some cases to meet the power demand. By storing energy at times of peak production, energy can be released for consumption at times of minimum energy production. Biogas storage tanks are integrated to ensure a continuous flow of biogas into the CHP system [4].

Carbon capture and storage (CCS) methods can be integrated to separate the CO_2 from the flue gases which are generated during combustion within the CHP system. The amine absorption is used in industry

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due to the commercial availability. Pipelines are the main transportation option in many regions. Ship, rail, and truck transport is available depending on the volume of CO_2 output. The CO_2 can then be permanently stored in geological formations [5].

An economic study will also reveal which options are financially feasible for the case study farm. State of the art research has been conducted within this sector, however this study identifies gaps which are explored further. The implementation of AD systems on medium scale arable farms has been investigated for the supply of heating, cooling, and power through a trigeneration system [6]. As arable farms only consider crops, further research and analysis is required to determine the feasibility of implementing this system for farms containing livestock. Small and medium scale farms have been proven to achieve a self-sufficient energy supply only when all resources are combined [6]. This study will investigate the possibility of generating excess energy while distributing excess electricity to the grid or surrounding community. Each case study is independent based on the electrical and heating demands dictated by the on-site activities. Without providing the necessary research, it is unlikely that a net-zero solution will be found for this farm. The farm owner will not have the research capability due to critical time constraints, and a lack companies offering economic investment within this area. Carbon capture and storage is a developing technology, however it is often omitted from net-zero energy generation system feasibility studies. By designing and implementing a CCS model into the simulating software, accurate results can be used to determine the feasibility of integrating CCS for this study.

2. METHODOLOGY

2.1 Farm Electrical & Heating Demand

The farm comprised of 850 cattle, 850 lamb, and 200 acres of crops spanning 600 acres of land. Milking machines, electrical cooling, water heaters, and agricultural vehicles are used on site. Consumption data was only available for 3 months, so the remaining data was extrapolated from the average UK consumption across the previous 6 years. Assuming a continuous 24hour CHP system, the average power required to meet the electrical demand was calculated to be 65.2 kW, with a maximum and minimum of 81.54 kW and 51.65 kW respectively. This is displayed in Figure 1.

To estimate the heating demand of the site, it was assumed that 7,500 litres would be required to heat all buildings. The oil higher heating value was used within the calculation to yield an upper limit approximation, while assuming a boiler efficiency of 90% [7]. Calculations identify a heating demand of 9.54 kWth.

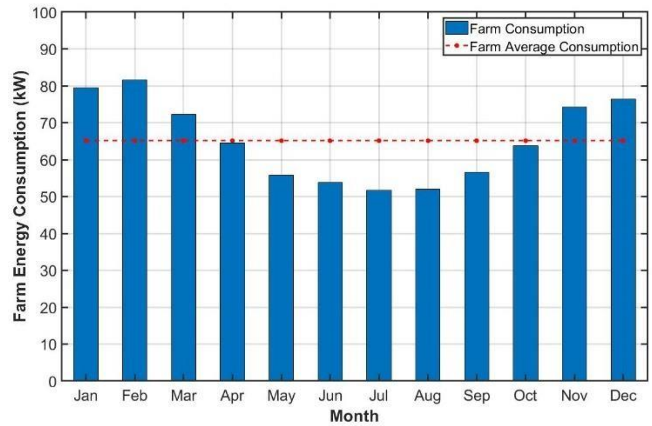

Fig. 1. Monthly power requirements & average capacity (kW)

2.2 Farm Waste & Analysis

It is expected for dairy cows to produce 35 kg of organic waste per day, while sheep produce 2 kg [8]. These values were used to determine the waste product feedrate for simulation. Table 1 displays the manure output and dry matter content [9]. The yield of wheat straw is 4.2 t/year, while spring and winter barley straw combine for 5.7 t/year. This gives a feedrate of 0.00013 kg/s and 0.00018 kg/s respectively.

Tab. 1. Waste material produced by livestock

Parameter	Dairy Cow	Sheep
Manure output per animal (kg/day)	35	2
Number of animals	850	850
Manure per day (t/day)	29.75	1.70
Manure output (kg/s)	0.3443	0.0197
Dry matter (%)	23.5	21.0

The ultimate analysis of each feedstock was required for analysis. Table 2 identifies the weight percentage breakdown of the constituent elements within cow waste, sheep waste, wheat, and barley [10]–[13].

Tab. 2. Ultimate analysis of waste (wt.%)

Element	C	H	O	N	S	Cl
Cow	49.85	6.05	40.52	2.81	0.77	-
Sheep	54.64	7.18	32.04	4.83	1.31	-
Wheat	48.86	6.49	43.56	0.71	0.18	0.19
Barley	42.08	6.32	50.95	0.65	-	-

2.3 ECLIPSE simulations and setup validation

The simulating software used for this study is ECLIPSE. This allows engineering processes to be simulated with background calculations. Anaerobic digestion of biomass and the combustion of biogas is modelled through the use of chemical equations. The software utilises these equations to execute a mass and energy balance program to calculate the output streams [14]. The chemical composition of biomass will determine the yield of biogas. The organic substrates contained within the waste will influence the production of methane as this undergoes a degradation reaction forming CH_4 and CO_2 as in Equation (1). Subscripts a, b, and c represent the number of atoms in carbon, hydrogen, and oxygen respectively.

$$C_A H_B O_C + \left(a - {}^{b}/_{4} - {}^{c}/_{2}\right) H_2O \rightarrow ({}^{a}/_{2} + {}^{b}/_{8} + {}^{c}/_{4}) CH_4 + ({}^{a}/_{2} + {}^{b}/_{8} + {}^{c}/_{4}) CO_2 \quad (1)$$

A mixture of CH_4 and CO_2 will undergo combustion within the biogas engine generator. Equation (2) shows the chemical reaction of this process [15]. Coefficients x_1 to x_8 represents the number of moles for each species, X denotes the molar ratio of CO_2 to O_2 in the gas mixture, ψp is the primary zone equivalence ratio, and ε is the molar ratio of gas mixture to fuel.

$$\psi_p \epsilon (0.65 CH_4 + 0.35 CO_2) + \frac{1}{1+X}(O_2 + XCO_2) \rightarrow x_1 CO_2 + x_2 H_2O + x_3 CO + x_4 OH + x_5 H + x_6 O + x_7 O_2 + x_8 H_2 \quad (2)$$

An amine absorption carbon capture system was simulated. Waste heat from exhaust gases was recovered to provide heat to facilitate the chemical reactions required for the separation of CO_2 from flue gases. Bicarbonate and carbamate formation is shown in Equation (3) and Equation (4) respectively [16].

$$CO_2 + 2H_2O \rightarrow H_3O^+ + HCO_3^- \quad (3)$$
$$MEA + HCO_3^- \rightarrow MEACOO^- + H_2O \quad (4)$$

A standard operating condition of 65.2 kWe was selected as this is the average farm consumption. Biogas generators are designed to operate from approximately 70% of the machine rating [17]. From this, a 100 kWe biogas generator was selected to run continuously at 65.2 kWe to meet the energy requirements with suitable biogas energy storage. This design choice gives the option to increase the energy production occasionally to meet the maximum requirement of 81.54 kWe. Six run scenarios were setup to produce biogas through the AD of organic waste. A 100 kWe biogas generator operating at 65.2% capacity within a CHP system was then modelled. A simulation was set to investigate the maximum energy production capacity of the farm. A 250 kWe biogas generator was modelled. The maximum production would then be multiple units of the same electrical load. This unit size provides advantages over a single 1 MWe unit. As biogas production can be inconsistent, single or multiple units may be turned off dependent on the biogas production. This reduces power loss due to auxiliary systems on the CHP unit. The organic waste and CHP parameters utilised within each run are stated below.

- Run 1: Cow waste (100 kWe at 65.2% capacity)
- Run 2: Sheep waste (100 kWe at 65.2% capacity)
- Run 3: Cow waste and sheep waste mix (100 kWe at 65.2% capacity)
- Run 4: Cow waste, sheep waste, wheat straw, and barley straw mix (100 kWe generator at 65.2% capacity)
- Run 5: Cow waste and sheep waste mix (100 kWe generator at 100% capacity)
- Run 6: Cow waste and sheep waste mix (250 kWe generator at 100% capacity)

The anaerobic digestion process was simulated within ECLIPSE as in Figure 2. This biogas was then used as an input into the CHP system for the provision of electricity and heat. For the carbon capture system, aqueous MEA solvent was selected at 30 wt.%, with a stripper temperature of 120 °C, and lean solvent temperature of 25 °C [16]. Figure 3 displays the CHP with carbon capture model.

The ECLIPSE model was formed by calibrating real 100 kWe and 250 kWe biogas generators [18], [19]. The biogas fuel input would be used decrease the operating capacity to the standard operating condition of 65.2 kWe. Table 3 identifies that the error is less than 5% for all key output parameters for each generator.

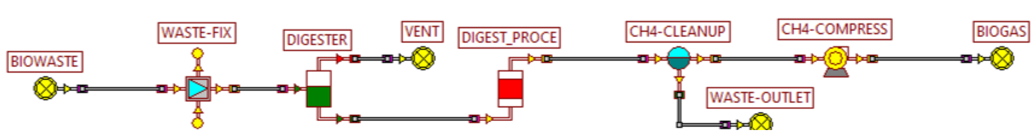

Fig. 2. ECLIPSE model of anaerobic digestion system

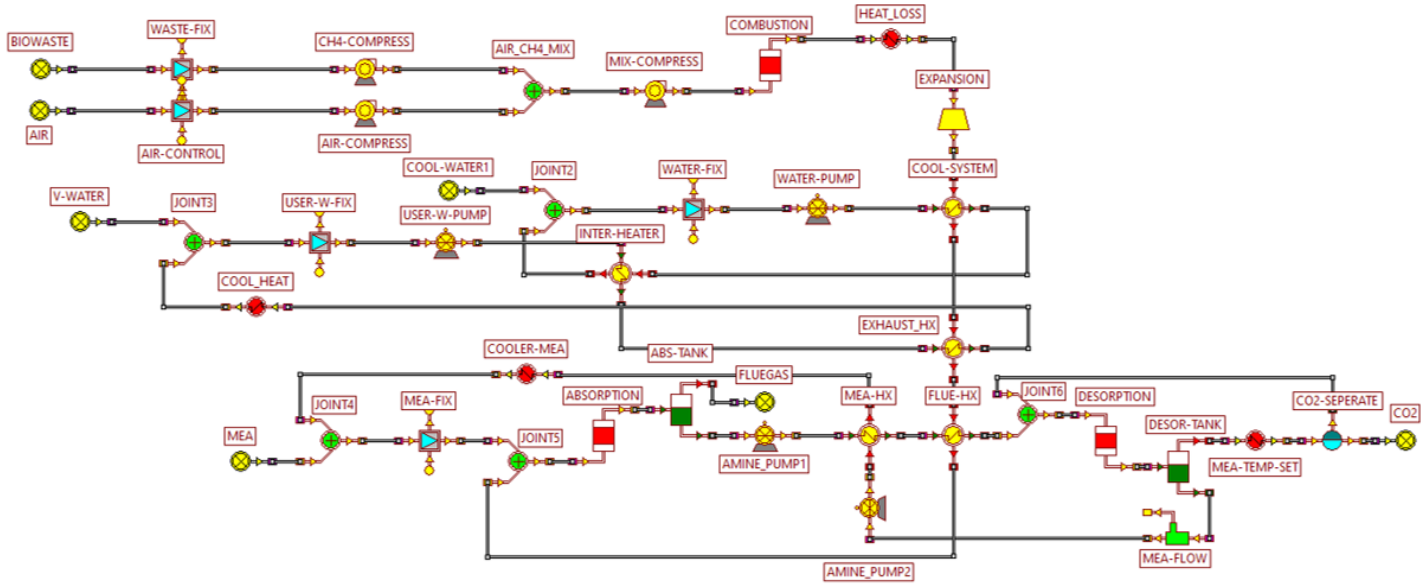

Fig. 3. ECLIPSE model of CHP with carbon capture system

Tab. 3. Error analysis of ECLIPSE model for each biogas CHP system

Parameter	100 kWe			250 kWe		
	Real	Model	Error (%)	Real	Model	Error (%)
Electrical output (kWe)	100	100.12	-0.12	250	250.79	-0.32
Heat output (kWth)	175	175	0.00	350	350	0.00
Electrical efficiency (%)	29.70	31.10	-4.72	34.03	35.72	-4.97
Heat utilisation factor (%)	52.00	54.36	-4.54	48.33	49.85	-3.15
Overall efficiency (%)	81.70	85.46	-4.61	82.38	85.58	-3.88

3. METHODOLOGY

3.1 CHP & CCS System Performance

A summary of CHP system performance is given for each simulation in Table 4. Run 1 utilises organic cow waste only to yield biogas of 52.8% CH_4 concentration. There was sufficient biogas to achieve the electrical demand of 65.2 kWe, with η_{elec} = 27.2%. The heating demand of 9.54 kWth was met with 133 kWth available.

Run 2 produced biogas through AD of sheep waste only. Despite using all the biogas produced, only 60.7 kWe and 121 kWth was produced. Therefore the electrical demand was not met.

Run 3 combined all of the cow and sheep waste available within the AD process. Due to proportion of waste available, CH_4 concentration and LHV increased slightly from run 1. As a result, the electrical and heating demands were met with the CHP system performing almost identical to run 1.

Run 4 utilises all livestock waste and crops in AD to produce biogas. Due to the low feedstock of wheat and barley straw, most biogas is produced from the livestock waste. Therefore, there is minimal variation from run 3. When only wheat and barley straw are used for AD, the combined output is only 4.0 kWe and 9.0 kWth, and so the CHP system cannot meet either demand.

Run 5 simulates the 100 kWe biogas generator at full capacity with biogas derived from cow and sheep waste, producing 100.1 kWe and 175 kWth. This identifies that the maximum farm demand of 81.54 kWe can be met during periods of peak energy consumption, while also meeting the thermal energy requirement. This requires a 53.4% increase in biogas fuel consumption. Due to this, the overall CHP efficiency decreases to 74.4%.

Run 6 utilised an adapted model for the simulation of a 250 kWe generator at full capacity. The biogas characteristics were identical to runs 3 and 5 (cow and sheep waste), however the biogas mass flow rate ($\dot{m}$) was scaled for the larger electrical load. The results show that the electrical and heating demands were both met at 250.4 kWe and 350.0 kWth respectively. The electrical efficiency was 32.6% and 78.1% overall, both increasing relative to run 3 which used the 100 kWe generator model. The simulation results are in agreement with the theory as η_{elec} increases while $\eta_{overall}$ decreases with the increase in installed power. The maximum electrical production of the site was calculated to be 1 MWe as in Equation (5). From the AD of of cow and sheep waste,

Tab. 4. CHP system performance

Parameter	100 kWe						250 kWe	
	Cal.	Run 1	Run 2	Run 3	Run 4	Run 5	Cal.	Run 6
Generator capacity (%)	100	65.2	65.2	65.2	65.2	100	100	100
Feedstock type	-	Cow	Sheep	C/S	All	C/S	-	C/S
Maximum biogas $\dot{m}$ (kg/s)	0.0143	0.2090	0.0124	0.2216	0.2330	0.2216	0.0312	0.2216
Maximum biogas $\dot{Q}$ (m3/s)	0.0131	0.1593	0.0100	0.1695	0.1780	0.1695	0.0285	0.1695
CH_4 Concentration (%)	70.0	52.8	58.5	53.2	53.1	53.2	70.0	53.2
Set biogas $\dot{m}$ (kg/s)	0.0143	0.0164	0.0124	0.0163	0.0163	0.0250	0.0312	0.0520
Air $\dot{m}$ (kg/s)	0.1430	0.1640	0.1240	0.1630	0.1630	0.2500	0.3118	0.5200
LHV of biogas (kJ/kg)	22518	14636	17258	14790	14743	14790	22518	14790
Total thermal input (kWth)	321.9	240.0	214.0	241.1	240.3	369.8	702.0	769.1
Electrical output (kWe)	100.1	65.2	60.7	65.2	65.3	100.1	250.8	250.4
Electrical efficiency (%)	31.1	27.2	28.4	27.1	27.2	27.1	35.7	32.6
Heat output (kWth)	175	133	119	133	133	175	350	350
Heat utilisation factor (%)	54.4	55.4	55.6	55.2	55.3	47.3	49.9	45.5
Total output (kW)	275.1	198.2	179.7	198.2	198.3	275.1	600.8	600.4
Overall CHP efficiency (%)	85.5	82.6	84.0	82.2	82.5	74.4	85.6	78.1
Heat / Electricity ratio	1.75	2.04	1.96	2.04	2.04	1.75	1.40	1.40

there was sufficient biogas mass flow rate to power four 250 kWe biogas generator units.

$$N_{gens} = \frac{\dot{m_{Max}}}{\dot{m_{250\,kWe}}} = \frac{0.222}{0.052} = 4.26 \rightarrow 4 \qquad (5)$$

When integrating the amine absorption carbon capture system into the 250 kWe CHP system, 85.1% of the CO_2 was removed from the exhaust gases. The heating requirement of the carbon capture system was met by the heat recovery of the CHP system, with 350 kWth available for use on site. Only 0.42 kWe was required to drive the pumps within the system.

3.2 CHP System Emissions

The direct CO_2 emissions from each CHP system are shown in Table 5. For the 100 kWe system, emissions are evaluated for the 65.2 kWe operating condition. Results show that run 2 (sheep waste) produced the least emissions, however this simulation did not meet the electrical energy demand. Runs 1, 3, and 4 gave the least emissions for a 100 kWe generator at 65.2% capacity with 410 t/year, while meeting all requirements.

The biogas generator emissions from run 3 were compared to a 100 kWe diesel engine operating at 65.2% capacity within a CHP system [20].

This has less heat recovery compared to the biogas CHP, and so emissions increase relative to the power output. This results in a 8.5% increase in annual emissions for the diesel engine.

As generator size was scaled from 100 kWe at 65.2% capacity to 250 kWe at full capacity, fuel consumption is increased significantly, producing 1312 tCO_2/year. When this was compared to a 250 kWe diesel engine at full capacity, the diesel engine emissions were 73% larger at 2274 t/year [21]. To calculate the emissions for a 1 MWe CHP system, the values were scaled proportionally from the 250 kWe case.

3.3 Full Project Emissions

ECLIPSE simulations were used to determine the CO_2 emissions of each CHP system. This gave 410 tCO_2/year for the 100 kWe system, and 5,248 tCO_2/year for the 1 MWe setup.

Tab. 5. CHP system emissions

Variable	100 kWe (65.2% capacity)					250 kWe (full capacity)		1 MWe
	Diesel	Run 1	Run 2	Run 3	Run 4	Diesel	Run 6	scaled
CO_2 emission $\dot{m}$ (kg/s)	0.014	0.013	0.013	0.013	0.013	0.072	0.042	0.166
CO_2 emissions (g/kWh)	444	236	230	236	236	1035	249	998
CO_2 emissions (t/year)	445	410	363	410	410	2274	1312	5248

However, as biogas from AD is used as fuel, the CO_2 released from complete combustion within the CHP units can be equated to the CO_2 consumed by the plants. From this, CO_2 released due to combustion is treated as zero within Table 6 [1]. The CO_2 displaced by heating oil was calculated using the oil carbon factor of 0.258 $kgCO_2/kWh$ [22]. The CO_2 emissions displaced from the grid were calculated using a grid carbon factor of 0.193 $kgCO_2e/kWh$ [23].

The simulation for CCS alongside the CHP demonstrated that 85.1% of the CO_2 can be removed from the exhaust gases. This is equivalent to removing 4466 tCO_2/year from the atmosphere, neglecting emissions from transportation or storage. Table 6 presents the net CO_2 displaced for each option, indicating that carbon negative farming can be achieved. The 1 MWe and CCS option yielded the maximum reduction in emissions at 6,158 tCO_2/year.

Tab. 6. Annual CO2 displaced for each option

Emission Source	100 kWe 65.2% cap.	1 Mwe 65.2% cap.	1 MWe & CCS Full cap.
Combustion	0	0	0
Heating	-6,475	-6,475	-6,475
Grid	-110,221	-1,685,649	-1,685,649
CCS	0	0	-4,460,453
Net CO_2	-116,695	-1,692,124	-6,152,577

3.4 *Economic Analysis*

The non-recurring system costs were extracted from quotations which were based on the simulation results. The cost of the CCS system was scaled appropriately from natural gas cogeneration project [24]. The agricultural vehicle fuel cost was based on the current rate of red diesel at £1.04/L [25]. Heating oil cost was based on a rate of £0.80/L with 2500L consumed annually [26].

For the 1 MWe option, assuming 80 kWe is used on site, 920 kWe is available to be redistributed and sold to the electricity grid. With the British Gas selling rate of £0.064/kWh, £515,789 can be collected across one year from the Smart Export Guarantee [27]. With the annual electricity usage at an average rate of £0.154 /kWh, this accumulates to £87,930. This is capital which would be saved per year if on-site energy is provided from the renewable options provided. Annual operational and maintenance (O&M) costs were set at 10% of the initial capital expenditure to purchase the biogas machinery. The cost associated with the storage and transportation of CO_2 within Europe can be estimated at approximately £28.4 /tCO_2 [5], with 4466 tCO_2 removed.

For the 1 MWe option with CCS, the CO_2 removal is equivalent to removing CO_2 from the atmosphere and can be quantified through carbon credits. These carbon credits can be traded on the market with a variable rate to offset emissions from other companies [28]. Assuming a rate of £15 /tCO_2, £66,989 can be recovered annually.

Each cost has a rate which varies slightly with time. These rates were accurate as of February 2023. All costs are summarised within Table 7I. This indicates that with the 100 kWe option, there is a moderate initial investment to construct the system, but maintains lower operational costs than the current farm. For the 1 MWe option, there is a large initial investment, however there is annual revenue from selling energy back to the grid. For the 1 MWe system with CCS and CO_2 transport, the increase in initial capital investment alongside higher O&M costs heavily limit the economic feasibility.

Tab. 7. Annual recurring and non-recurring cost breakdown of options

Type	Item	Current	70 kWe	1 MWe	1 MWe with CCS&T
Non-Rec	Generator	0	23,859	290,205	290,205
	Digester	0	80,545	644,358	644,358
	Storage tank	0	26,000	640,000	640,000
	CCS system	0	0	0	3,500,000
Rec	Red diesel	85,754	85,754	85,754	85,754
	Heating oil	1,998	0	0	0
	Energy grid sales	0	0	-515,789	-515,789
	Electricity	87,930	0	0	0
	O&M	0	13,040	157,456	507,456
	Carbon credit sales	0	0	0	-66,986
	CO_2 transport & storage	0	0	0	126,842
Total Non-Recurring Costs		0	130,404	1,574,563	5,074,563
Total Recurring Costs		175,682	98,794	-272,579	137,278

The levelised cost of energy (LCOE) is an economic measure of the discounted cost of energy production across a project lifetime [6]. Equation (6) identifies the formula used to calculate the LCOE [29].

$$LCOE = \left(\sum_{n=1}^{N} \frac{C_n + O_n + V_n}{(1+d)^n}\right) / \left(\sum_{n=1}^{N} \frac{E_n}{(1+d)^n}\right) \quad (6)$$

with capital cost C_n, fixed operating cost O_n, variable operating cost V_n, energy generated E_n and discount rate d for a project ranging from year n to year N. The costs required to construct, operate and run the digesters, generators and storage vessels are included within Table 7. The lifetime was set at 20 years, discount rate set at 6% to match similar CHP projects, and O&M costs remained set to 10% of machine cost subject to a 2% growth rate [6],[30]. The LCOE was calculated for each 100 kWe and 1 MWe options yielding values of £60.41/MWh and £47.34/MWh respectively. The LCOE was calculated to be £152.58 /MWh for the 1 MWe with CCS and CO_2 transport. This value is not used for comparison as no additional energy was produced.

The payback period denotes the time required to offset the investment of a given project. A payback period shorter than the project lifetime indicates that the project can be deemed economically feasible. This was calculated to be 1.9 years for the 100 kWe option. The value is heavily influenced by electricity usage, and therefore the cost associated. A sensitivity analysis was carried out with half the annual electricity usage, and therefore half the annual savings recovered. This yielded a new payback period of 4.4 years. For the 1 MWe option, the payback period was calculated as 3.5 years. A sensitivity analysis was also carried out as this value is strongly affected by the electricity selling rate and the electrical energy consumption. The British Gas selling rate of £0.064 /kWh was decreased to £0.032 /kWh, while also assuming half of the annual cost were recovered from the electricity usage. A payback period of 10.8 years was yielded. When considering the 1 MWe option with CCS and CO_2 transport, the financial investment is not recovered within the lifetime of the project in the current state, and so is of higher risk until the setup costs decrease with more demand. The 100 kWe and 1 MWe options, inclusive of the sensitivity analysis, had a payback period shorter than the project lifetime of 20 years. These projects can then be determined economically feasible.

4. CONCLUSION

This study demonstrates that AD of biomass from a large scale farm can produce sufficient biogas to power a 100 kWe or 1 MWe CHP system.

The electrical demand of the farm is averaged at 65.2 kWe, with a heating demand of 9.54 kWth. Most biogas is produced via the anaerobic digestion of cow and sheep waste. With a variable power demand from 51.65 kWe to 81.54 kWe, a 100 kWe CHP system was selected to meet site demands only. This had a standard operating condition of 65.2 kWe, but provided an option to increase the operating capacity to meet the peak demands. Run 3 performed best by meeting the electrical and heating requirements with η_{elec} = 25.7% and $\eta_{overall}$ = 82.2%. This reduced net emissions by 116.7 tCO_2/year. The maximum electrical production capacity of the farm was investigated. Using cow and sheep waste, 1 MWe can be produced using four 250 kWe units with η_{elec} = 32.6%, $\eta_{overall}$ = 78.1%, and a net emission reduction of 1692.1 tCO_2/year. An amine absorption carbon capture system was integrated. This separated 85.1% of the CO2 within the flue gas stream. Resultingly, there is potential for a net reduction of 6157.8 tCO_2/year.

The LCOE was calculated for the 100 kWe and 1 MWe systems, excluding CCS and CO_2 transport, for an assumed lifetime of 20 years. These equate to £60.41/MWh and £47.34 /MWh respectively. The cost summary and sensitivity analysis established a payback period range for each option. This was calculated to be 1.9-4.4 years for the 100 kWe system, and 3.5-10.8 years for the 1 MWe system. As each are below the 20 year lifetime assumption, they are deemed economically feasible investments.

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DECLARATION OF INTEREST STATEMENT

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. All authors read and approved the final manuscript.

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