Synergy between feedstock gate fee and power-to-gas: An energy and economic analysis of renewable methane production in a biogas plant

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ABSTRACT

Biogas is an instrument of synergy between responsible waste management and renewable energy production in the overall transition to sustainability. The aim of this research is to assess the integration of the power-to-gas concept into a food waste-based biogas plant with the goal to produce renewable methane. A robust optimisation was studied, using linear programming with the objective of minimising total costs, while considering the market price of electricity. The mathematical model was tested at an existing biogas power plant with the installed capacity of 1 MW_{el}. It was determined that the integration of power-to-gas in this biogas plant requires the installation of ca. 18 MW_{el} of wind and 9 MW_{el} of photovoltaics, while importing an additional ca. 16 GWh_{el} from the grid to produce 36 GWh of renewable methane. The economic analysis showed that the feedstock gate fee contributes significantly to the economic viability of renewable methane: a change in the feedstock gate fee by 100 €/tonne results in a decrease of production costs by ca. 20-60%. The robust nature of the model showed that uncertainties related to electricity production from wind and photovoltaics at the location increased the cost of gas production by ca. 10-30%.

Keywords: Biogas; food waste; optimisation; uncertainty; renewable gas

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1 INTRODUCTION

Biogas is a renewable source of energy produced by decomposition of organic materials (feedstocks) under an oxygen-free atmosphere and controlled temperature in the process known as anaerobic digestion (AD) [1]. Commonly used feedstocks to produce biogas are animal manure and agricultural residues [2], energy crops [3], combined with various waste streams originating from food processing value chains [4].

In 2018 the European Commission adopted a recast of the Renewable Energy Directive, which stated that the biomass fraction of municipal waste, biowaste and streams from industry should play a greater role in future biogas production, since they have low indirect land-use change impact to produce biofuel [5]. In recent years, the developed biogas sectors among the European countries have limited the utilisation of energy crops, like maize silage and corn, to a share of 30-50% of the total input feedstock [6,7].

Since the cost of feedstock accounts for the highest share of operating costs for AD, biogas plants are exploring a transition towards low-cost source material suitable for biogas production [8]. The purchase price for the most common feedstocks in the biogas sector − maize and grass silage fluctuates between 15 and 40 €/tonne of raw material [9], depending on the country and the crop quality. In addition, energy crops in biogas production give rise to environmental, social and economic issues due to the competition with food production on arable land [10].

Energy recovery of organic waste materials using biogas technology as a replacement for landfilling has shown to avoid environmental burdens [11] and contributes to the perspective of circular economy [12]. Agri-food waste and animal manure have a zero cost, while the purchase price for food waste and other bio-waste types is between -60 and 0 €/tonne [9]. The minus sign indicates that the biogas plant receives a "gate fee − *GF*" from the waste producers to receive and handle their biodegradable waste [8]. The amount of the *GF* depends on the origin and complexity of the waste [13], and in some cases it can be as high as 100 $/tonne [8].

From an economic point of view, the introduction of *GF* in the operation of biogas plants has proven to be a promising business model, as it can amount to 80% of the total biogas plant income [13]. International Energy Agency projects that food waste disposal on landfills will be banned by 2040, which could be an attractive opportunity for biogas plants to consider more using food waste in biogas production [8]. In addition, such measures will result in increased separate waste collection costs, which will ultimately lead to increased gate fees in biogas plants and additional financial income [14].

The main component of biogas is methane (45-70% vol. share of CH_4), which makes biogas applicable as an alternative to natural gas [15]. In past decades, strong public subsidy mechanisms [16] for electricity production in the form of feed-in-tariffs and feed-in-premiums have resulted in a high level of biogas penetration in the European electricity sector [17]. The level of subsidies depends on the country, and in all European countries is not lower than 8.0 €-Cent/kWh$_{el}$ [18], which is almost the twice the average wholesale market price of electricity in the EU.

Part of the heat produced in biogas combined heat and power (CHP) unit is used to maintain a constant temperature in the digester [19], while residual high-grade heat is used for various heating purposes like district heating [20], Organic Rankine Cycle [21], for drying of materials and heating greenhouses [22].

According to the European Biogas Association, at the end of 2017, there were 17,783 biogas plants in Europe operating in CHP mode [23]. Since subsidies are granted only for a certain period, usually not longer than 15 years [18], biogas plant owners have started seeking alternative biogas utilisation pathways [24].

It has been shown that in the post-subsidy era, the operation of biogas plants on the day-ahead electricity market is not viable [25], since the cost of electricity production in CHP meets the price of electricity on the market [13]. On the other hand, a minority of biogas plants in

Europe, only 540 of them [23], operate in the biogas upgrading mode, removing non-methane components from biogas and producing biomethane, a gas with a 99% share of CH_4 [26], which can be directly injected into the natural gas grid. Biogas upgrading technologies require electricity for their operation, on average ca. 0.30 kWh_{el} per Nm^3 of fed biogas, while some also require solvents, water and heat [26]. The relatively high level of subsidies for biogas CHP and the high investment costs in the upgrading units have resulted in a rather low number of upgrading installations compared to biogas CHP.

In the transition by the biogas sector towards low-cost sustainable feedstocks and viable operation on energy markets, the integration of variable renewable energy sources (RES) [27], primarily wind and photovoltaics (PV), seems an attractive option, since their capacity is continuously on the increase globally, providing low-cost electricity [28].

In Germany, utilisation of excess electricity from wind farms for biogas upgrading has shown potential for converting and storing of surplus electricity without long transport routes [29]. Utilising 0.70 $TW_{el}h$ of excess electricity to 480 biogas plants could produce $100 \cdot 10^6$ Nm^3/y of upgraded CH_4.

Apart from covering the electricity demand in a certain process, excess electricity from variable RES is also utilised to produce hydrogen (H_2) through the process of water electrolysis [30]. The integration of renewable H_2 in fuel production can reduce the demand for biomass, while simultaneously increasing the flexibility of the energy system by enabling higher penetration of variable RES in energy systems [31].

The surplus energy generated by wind turbines or PV modules can also be used in a technology called power-to-gas (P2G), where the carbon dioxide (CO_2) and H_2 produced in electrolysers are converted to synthetic natural gas (synthetic methane/e-methane, e-CH_4) in the methanation process [32]. Since both biogas CHP and biogas upgrading act as sources of

CO_2, the integration of the P2G concept together with sustainable biomass management offers a high gain perspective [33].

Installing a P2G unit near the biogas CHP unit ensures that both units can operate independently: when there is demand for P2G operations, biogas is used for methanation, and when it is not required, biogas is used in the CHP unit [34]. Moreover, electrolysers and methanators are sources of heat, where electrolysers usually provide low-grade heat [35], while methanators produce high-grade heat that can be used in local district heating appliances or in industrial processes [36].

The examples of integrating variable RES in renewable gas production are the *WindGas Falkenhagen* methanation plant [37] and the *Audi e-gas* plant [38], both located in Germany, where wind supplies electricity to run the P2G facilities. In Denmark, the *BioCat* plant uses CO_2 from biogas upgrading and renewable H_2 to produce synthetic CH_4, which is fed to the national gas grid [39]. Compared to biogas upgrading and separate CO_2 utilisation in P2G, the direct methanation of biogas [40] has proven the more efficient and less energy demanding process [41], enabling full carbon utilisation from biomass [42].

Synthetic natural gas produced in the direct methanation of biogas from the wastewater treatment plant has a CH_4 share of ca. 90%, with ca. 5% of H_2 [43]. The second P2G project by the *Audi e-gas* company in Germany, with direct methanation of raw biogas using renewable H_2, produces renewable methane with a 98% share of CH_4 [38]. Previous economic analyses have shown that the renewable gas produced by integrating P2G into biogas plants cannot be competitive in price with natural gas, unless there are subsidies [44].

The efficiency of the P2G concept is highly dependent on the metrological conditions at the location where wind and PV are studied [45]. Such energy systems usually operate connected to the electricity grid (on-grid), purchasing electricity from the grid at times when no wind/PV electricity is available and exporting electricity excess to the grid.

Finding the capacity of energy production units in the P2G concept is an optimisation problem [46] that requires system modelling on an hourly level, because of the variable nature of electricity generation and electricity market features [47]. In addition, optimising power production from wind and PV includes the involvement of uncertainties [48] due to variability in input data, which makes the developed mathematical model robust [49]. When optimising energy systems, the common objective functions (OF) are minimisation of total cost (or maximisation of total profit), minimisation of energy loss (maximisation of energy efficiency) and minimisation of environmental impact (usually expressed through CO_2-equivalent emissions) [50]. From the perspective of new technology integration in existing facilities, the choice to minimise the energy system's costs is commonly accepted [51], as long as it guarantees the security of supply and ensures technical-feasible operation.

Based on the detailed literature review of the biogas sector including available feedstocks, biogas utilisation pathways and integration of variable RES , there is no reported research that combines all these elements of the biogas chain into a holistic approach that integrally analyses the transition of the biogas sector after expiry of subsidy mechanisms for electricity production. To address this gap in the scientific literature, this study will develop a robust mathematical model with the goal of quantifying the integration of the P2G concept into an existing biogas plant operating under a feedstock gate fee business model. To develop and test the model, the following research objectives were appointed:

i) to optimise the integration of the variable RES in the operation of the existing biogas plant, using total cost minimisation as an objective function;

ii) to quantify the impact of the feedstock gate fee in the biogas plant on the cost of renewable methane production, with the aim of making it economically competitive with natural gas;

iii) to reveal the impact of uncertainty in electricity production from variable RES on the optimal economic solution and system operational features.

The hypothesis of this research is that the synergy between a feedstock gate fee business model and the integration of the P2G concept at the biogas plant can contribute to a significant reduction of renewable methane cost generation, which could be considered an alternative to subsidy mechanisms in the production of renewable gas.

2 MATERIALS & METHODS

This section provides a brief description of the methods applied in the study. The model for P2G integration into an existing biogas plant is presented, analysing key features of the system operation. The description of an optimisation problem includes variables, energy and mass equations and the objective function. The last part describes the assessment tool to evaluate the economic viability of P2G integration in the existing biogas plant.

2.1 Power-to-gas integration in a biogas plant operation

The integration of the P2G concept supported by wind and PV electricity in an on-grid biogas plant is presented in Figure 1, which was derived from previous studies [34,52]. Green lines indicate the flow of electricity, black lines indicate the flow of gases and red lines indicate heat flows. The electricity imported from the electricity market to cover the total demand is shown in orange. The studied model is arranged to select which electricity supply unit with its energy flow is most appropriate to be chosen, based on the defined objective function (OF). The assumption is that the size of the plant is small enough so that its operation on the market does not impact the electricity price. The results of the model are presented in the form of interval values, for a defined set of input data.

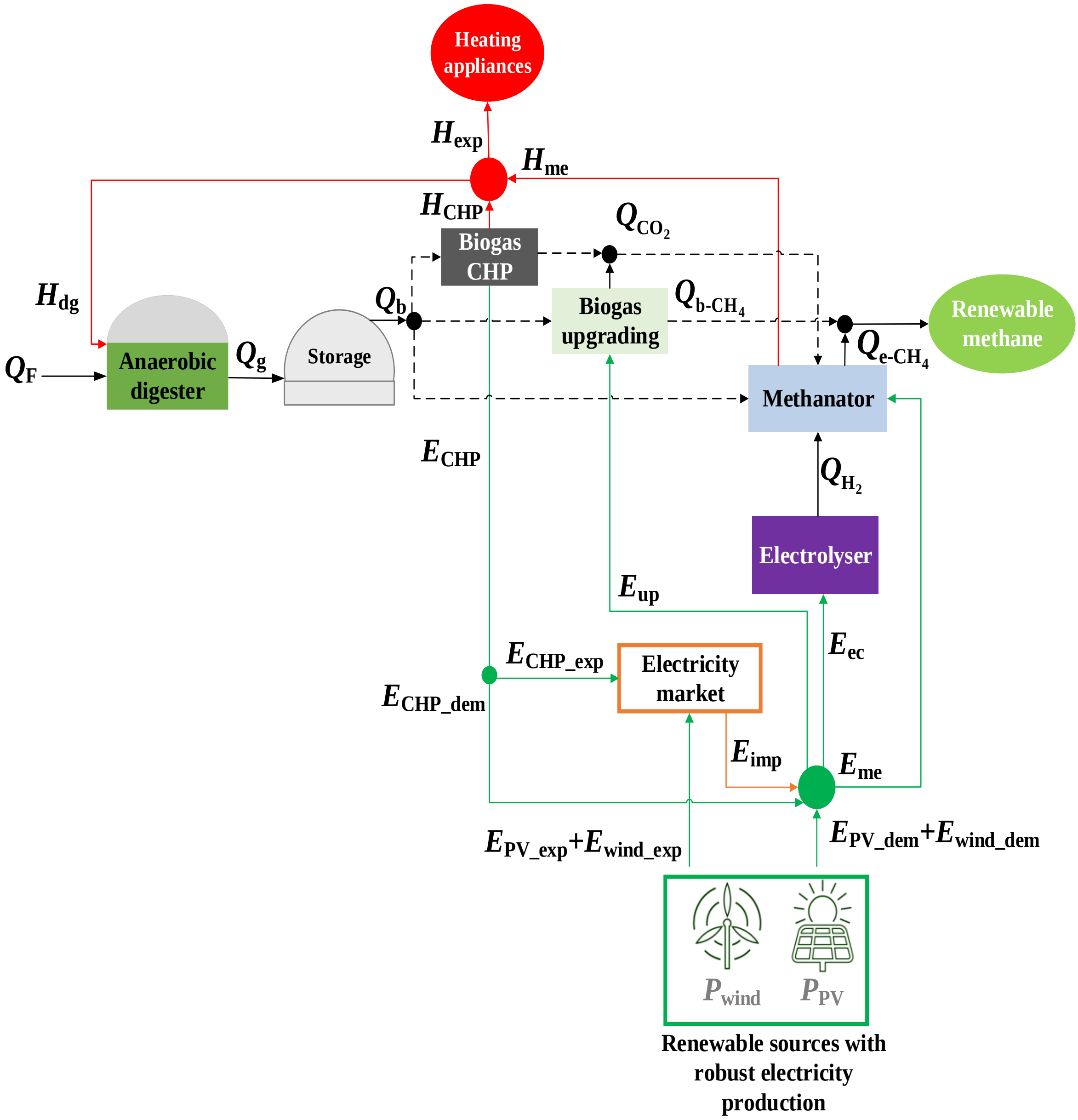

Figure 1: Power-to-gas integration in a biogas plant

2.2 Optimisation variables

A single objective optimisation model for a whole year time horizon [53] was used to optimise the energy flow and the capacity of the wind farm (P_{wind} [kW$_{el}$]) and PV plant (P_{PV} [kW$_{el}$]), the size of additional atmospheric biogas storage (V_{st} [m^3]), the capacity of an upgrading unit (c_{up} [Nm^3(biogas)/h]), an electrolyser (c_{ec} [Nm^3(H_2)/h]) and a methanation unit (c_{me} [Nm^3(e-CH_4)/h]), For solving the optimisation problem, the open-source programming language, Julia,

[54] and the JuMP modelling framework for mathematical optimisation [55] were used with the Clp solver for LP and Cbc for MILP.

2.3 Optimisation constraints

To produce renewable methane in the advanced biogas plant operation, the mathematical model must satisfy the hourly electricity demand in [kWh$_{el}$] for biogas upgrading ($E_{up,t}$), the H_2 production in the electrolyser ($E_{el,t}$) and the methanation process ($E_{me,t}$), which is the sum of demanded electricity produced in existing biogas CHP and in the newly installed wind and PV plants ($E_{wind\_dem,t}$+$E_{PV\_dem,t}$), plus the electricity imported from the electricity market ($E_{imp,t}$):

$$E_{\mathrm{up},t} + E_{\mathrm{ec},t} + E_{\mathrm{me},t} = E_{\mathrm{CHP\_dem},t} + E_{\mathrm{wind\_dem},t} + E_{\mathrm{PV\_dem},t} + E_{\mathrm{imp},t} \tag{1}$$

To calculate the electricity demand for biogas upgrading [56], the following relation was considered [26,57]:

$$E_{\mathrm{up},t} = \frac{Q_{b,t} \cdot e_{\mathrm{up}}}{\eta_{\mathrm{up}}} \tag{2}$$

where $Q_{b,t}$ is the biogas flowrate entering the upgrading unit [Nm^3/h]; e_{up} is the specific electricity consumption [kWh$_{el}$/Nm^3], and η_{up} is the upgrading efficiency [−]. The biogas flowrate supplied to the upgrading unit at any time cannot exceed the installed upgrading capacity:

$$Q_{\mathrm{b},t} \le c_{\mathrm{up}} \tag{3}$$

For the purpose of this research, an estimation was taken into account that, at the exit of the biogas upgrading unit, only two streams are present: bio-methane (b-CH_4) and pure CO_2 [58]:

$$Q_{\mathrm{b},t} = Q_{\mathrm{b\text{-}CH_4},t} + Q_{\mathrm{CO_2},t} \tag{4}$$

To calculate the flowrate of biomethane produced, the volume share of CH_4 in the biogas, $x(CH_4)$ is multiplied by the biogas fed to the upgrading unit.

The capacity of the atmospheric biogas storage placed between the anaerobic digester and the upgrading unit is defined using the following relations [59]:

$$SOC_t \leq V_{\mathrm{st}} \tag{5}$$

$$SOC_t = SOC_{t+1} + Q_{\mathrm{f},t} - Q_{\mathrm{b},t} \tag{6}$$

where SOC_t is the state of charge of the biogas storage [m^3], and $Q_{\mathrm{f},t}$ is the biogas production rate in the anaerobic digester [Nm^3/h]. The *SOC* in the initial moment (t=0 h) is the same as at the end of the year (t=8760 h), which means that biogas storage is not a source of biogas generation.

The energy required for electrolysing H_2O to produce H_2 [60] is defined by the following relation [57]:

$$E_{\mathrm{ec},t} = \frac{Q_{\mathrm{H_2},t} \cdot e_{\mathrm{ec}}}{\eta_{\mathrm{ec}}} \tag{7}$$

where $Q_{\mathrm{H_2},t}$ is the H_2 production rate [Nm^3/h]; e_{ec} is the specific electricity consumption of the electrolyser [kWh$_{\mathrm{el}}$/Nm^3], and η_{ec} is the electrolysis process efficiency [−]. Coupling P2G directly to the wind farm and the PV plant can result in a very small size of H_2 storage [61]. In this research, hydrogen storage has not been considered in the analysis. The amount of H_2 to convert captured CO_2 from biogas in the methanation process can be calculated based on the stoichiometric relation [62]:

$$Q_{\mathrm{H_2},t} = 4 \cdot Q_{\mathrm{b},t} \cdot x(\mathrm{CO_2}) \tag{8}$$

The H_2 flowrate from the electrolyser cannot exceed the installed capacity of the electrolyser:

$$Q_{\mathrm{H_2},t} \leq c_{\mathrm{ec}} \tag{9}$$

The energy required for the methanation reaction to produce e-CH_4 [60] is as [57]:

$$E_{\mathrm{me},t} = \frac{Q_{\text{e-CH}_4,t} \cdot e_{\mathrm{me}}}{\eta_{\mathrm{me}}} \tag{10}$$

where $Q_{\text{e-CH}_4,t}$ is the e-CH_4 production rate [Nm^3/h]; e_{me} is the specific electricity consumption of methanation [kWh_{el}/Nm^3], and η_{me} is the methanation process efficiency [−]. The e-CH_4 flowrate from methanation at any time cannot exceed the installed capacity of the methanator (c_{me}):

$$Q_{\text{e-CH}_4,t} \le c_{\mathrm{me}} \tag{11}$$

Since methanation is a highly exothermic chemical reaction with a heat release of −165 kJ/mol [35], the following relation presents the amount of heat released by the methanator:

$$H_{\mathrm{me},t} = h_{\mathrm{me}} \cdot Q_{\mathrm{CO}_2,t} \tag{12}$$

where h_{me} is the specific heat released during methanation [kWh_{th}/Nm^3] [35] and $Q_{\mathrm{CO}_2,t}$ is the CO_2 flowrate [Nm^3/h].

Electricity and heat produced in biogas CHP are defined using the following relations [25]:

$$E_{\mathrm{CHP},t} = \Delta H(\text{biogas}) \cdot \eta_{\mathrm{el}} \cdot Q_{\mathrm{b},t} \tag{13}$$

$$H_{\mathrm{CHP},t} = \Delta H(\text{biogas}) \cdot \eta_{\mathrm{th}} \cdot Q_{\mathrm{b},t} \tag{14}$$

where ΔH(biogas) is the lower calorific value of biogas [kWh_{th}/Nm^3] [63], $Q_{\mathrm{b},t}$ is the biogas outflow from the storage to the CHP unit [Nm^3/h], η_{el} is the efficiency of electricity production in the CHP, and η_{th} is the efficiency of heat in the CHP [64]. The biogas CHP operation is studied by the MILP approach, using B_{in} as a binary variable (0 or 1):

$$E_{\mathrm{CHP},t} = P_{\mathrm{CHP}} \cdot B_{\mathrm{in}} \tag{15}$$

The assumption was that biogas CHP operates either at the nominal power, or that it does not operate at all [25]. Moreover, it was calculated that the investment in the biogas plant was paid out before integrating the P2G concept and that running costs of the biogas CHP include maintenance, salaries and other costs [25], while the feedstock gate fee is considered as additional income.

Heating demand for the digester operation depends on the amount of input feedstock in the process [35] and can be estimated as:

$$H_{\mathrm{dg},t} = h_{\mathrm{dg}} \cdot Q_{\mathrm{F},t} \tag{16}$$

where h_{dg} is the specific heat demand for the AD process [$\mathrm{kWh_{th}}$/tonne] and $Q_{\mathrm{F}.t}$ is the amount of feedstock fed to the digester [tonne/h] for which the biogas plant receives a *GF*.

The excess heat exported to various heating appliances is defined by the following relation [19]:

$$H_{\exp,t} = H_{\mathrm{CHP},t} + H_{\mathrm{me},t} - H_{\mathrm{dg},t} \tag{17}$$

The electricity generation in the PV plant can be defined as [58]:

$$E_{\mathrm{PV},t} = P_{\mathrm{PV}} \cdot a_{\mathrm{PV},t} \tag{18}$$

where P_{PV} is the installed capacity of the PV plant [$\mathrm{kW_{el}}$] and a_{PV} is an exogenous parameter representing the hourly electricity generation from the PV plant per installed capacity at the location [$\mathrm{kWh_{el}}/\mathrm{kW_{el}}$]. To assess the uncertainties in electricity production from PV at the location, the robust optimisation (RO) approach was considered [65], and its expression (17) is modified accordingly by using the set of equations below [66,67]:

$$E_{\mathrm{PV},t} = P_{\mathrm{PV}} \cdot a_{\mathrm{PV},t} - \beta_{\mathrm{PV},t} \cdot \Gamma_{\mathrm{PV}} - \zeta_{\mathrm{PV},t} \tag{19}$$

$$\beta_{\mathrm{PV},t} + \zeta_{\mathrm{PV},t} \geq D_{\mathrm{PV},t} \cdot \lambda_{\mathrm{PV},t} \tag{20}$$

$$\beta_{\mathrm{PV},t}, \zeta_{\mathrm{PV},t}, \lambda_{\mathrm{PV},t} \geq 0 \tag{21}$$

$$\lambda_{\mathrm{PV},t} \geq P_{\mathrm{PV}} \tag{22}$$

where $\beta_{\mathrm{PV},t}$ [kWh$_{\mathrm{el}}$], $\zeta_{\mathrm{PV},t}$ [kWh$_{\mathrm{el}}$] and $\lambda_{\mathrm{PV},t}$ [kW$_{\mathrm{el}}$] are auxiliary variables of the robust mathematical model [66], Γ_{PV} is the robustness control parameter for PV, the value which reflects the ability of the system to cope with risk and that obtains values between 0 and 1 ($\Gamma_{\mathrm{PV}} \in [0,1]$), and $D_{\mathrm{PV},t}$ is any deviation by the PV system power profile from the mean value. Part of the electricity produced in the PV plant meets the demand for system operation ($E_{\mathrm{PV\_dem},t}$), while the rest is exported to the electricity grid ($E_{\mathrm{PV\_exp},t}$).

The total energy produced in the wind farm (E_{wind}) can be calculated as [58]:

$$E_{\mathrm{wind},t} = P_{\mathrm{wind}} \cdot a_{\mathrm{wind},t} \tag{23}$$

where P_{wind} is the installed capacity of the wind farm [kW$_{\mathrm{el}}$] and $a_{\mathrm{wind},t}$ is an exogenous parameter representing the hourly electricity generation in the wind farm per installed capacity at the location [kWh$_{\mathrm{el}}$/kW$_{\mathrm{el}}$]. The robust nature of electricity generation in the wind farm [65] can be defined as [66,67]:

$$E_{\mathrm{wind},t} = P_{\mathrm{wind}} \cdot a_{\mathrm{wind},t} - \beta_{\mathrm{wind},t} \cdot \Gamma_{\mathrm{wind}} - \zeta_{\mathrm{wind},t} \tag{24}$$

$$\beta_{\mathrm{wind},t} + \zeta_{\mathrm{wind},t} \geq D_{\mathrm{wind},t} \cdot \lambda_{\mathrm{wind},t} \tag{25}$$

$$\beta_{\mathrm{wind},t}, \zeta_{\mathrm{wind},t}, \lambda_{\mathrm{wind},t} \geq 0 \tag{26}$$

$$\lambda_{\mathrm{wind},t} \geq P_{\mathrm{wind}} \tag{27}$$

where $\beta_{\mathrm{wind},t}$ [kWh$_{\mathrm{el}}$], $\zeta_{\mathrm{wind},t}$ [kWh$_{\mathrm{el}}$] and $\lambda_{\mathrm{wind},t}$ [kW$_{\mathrm{el}}$] are auxiliary variables of the robust mathematical model [66], Γ_{wind} is the robustness control parameter for wind ($\Gamma_{\mathrm{wind}} \in [0,1]$), and $D_{\mathrm{wind},t}$ is any deviation by the wind power profile from the mean value. Part of the electricity produced by the wind farm meets the demand for system operation ($E_{\mathrm{wind\_dem},t}$), while the rest is exported to the electricity grid ($E_{\mathrm{wind\_exp},t}$).

2.4 Objective function

The minimisation of the total system cost was used in a single-objective function (f_{econ}) defined as follows [59]:

$$\min(f_{\mathrm{econ}}) = \min\left(\sum_{j=1} CRF \cdot CAPEX_j + \sum_{t=0}^{8760} \sum_{j=1} C_{\mathrm{imp},t} + OPEX_{j,t} \right) \tag{28}$$

where $CRF \cdot CAPEX_j$ is the total discounted investment cost of the technology j [€]; $C_{\mathrm{imp},t}$ is the total cost of imported electricity based on electricity demand and day-ahead electricity market prices [€], and $OPEX_{j,t}$ is the total cost for operation and maintenance of the technology j [€] in time step t. Since the capital cost is paid only once, at the start of the project, it does not have a temporal summation sign. To calculate the discounted investment cost of the technology, the capital price of investment was multiplied by a capital recovery factor (CRF) [68]:

$$CRF = \frac{i \cdot (1+i)^n}{(1+i)^n - 1} \tag{29}$$

where i is the interest rate, and n is the number of annuities received, in this case the number of operational years.

2.5 Levelized cost of electricity and renewable methane

To estimate the cost of electricity production from wind and PV at the location, the levelized cost of electricity ($LCOE$) [69] was used:

$$LCOE_j = \frac{CRF \cdot capex_j + opex_j}{\frac{E_j}{P_j}} \tag{30}$$

where $capex_j$ is the specific investment cost in the technology j [€/kW$_{el}$], $opex_i$ is the specific operational cost of the technology j on a yearly basis [€/kW$_{el}$)], E_j is the amount of electricity generated by the technology j [kWh$_{el}$], and P_j is the installed capacity of the technology j [kW$_{el}$].

The levelized cost of renewable methane ($LCORM$) produced in the proposed energy system which accounts for capital and operating expenditures, purchases and income from the studied energy and materials [70] can be estimated as:

$$LCORM = \frac{\sum_{j=1} CAPEX_j + \sum_{t=0}^{8760} \sum_{j=1} \frac{OPEX_{j,t} + C_{\text{imp},t} - R_{\text{exp},t} - H_{\text{exp},t} \cdot p_{\text{exp}} + Q_{\text{F},t} \cdot GF}{(1+i)^t}}{\sum_{t=1}^{N} \frac{G_t}{(1+i)^t}} \tag{31}$$

where $R_{\text{exp},t}$ is the revenue from electricity exported to the grid [€], $H_{\text{exp},t} \cdot p_{\text{exp}}$ is the revenue generated from the heat sold in variable appliances [€]; $Q_{\text{F},t} \cdot GF$ is the revenue of the biogas plant arising from the gate fee for feedstocks [€], which is negative, and G_{t} represents the amount of renewable methane produced by this model [kWh].

3 CASE STUDY

The present method was tested on the biogas plant which uses food waste and industry waste in its operation and is located near the city of Zagreb, Croatia. This biogas plant was chosen as a case study, since the authors of this research have already done several experimental and modelling studies on biogas production at the plant [71].

This research does not consider the current economic position of the biogas plant, as it operates under a subsidy agreement. This analysis is focused on determining a threshold (GF in Equation 31) that would indicate feasible conditions for the integration of P2G (in terms of optimised capacities) into a biogas plant for the production of renewable methane competitive with natural gas, only without subsidies.

3.1 Input data from the biogas plant

An experimental study at the biogas plant [71] showed that the average total solid (TS) content of food waste was ca. 20% and that biogas production from food waste is estimated at 0.566 Nm^3/kgTS. Multiplying these numbers and scaling to the biogas plant size shows that the average biogas production rate at the plant is 110 Nm^3 per tonne of raw feedstock.

According to the data obtained from the plant owner, the biogas production in digester is estimated at 10,000 Nm^3 per day, or Q_f=417 Nm^3/h, with the average share of methane being $x(CH_4)$=0.65 and ΔH(biogas)=6.4 kWh/Nm^3 [63]. Dividing the daily biogas production by the experimentally obtained biogas potential from food waste [71] results in an input amount of feedstock equal to Q_F=90 tonnes/day, or 3.75 tonnes/h.

The digester headspace has a storage capacity equivalent to 6 h of biogas production, or ca. 2,500 m^3. The specific heat demand of the digester to maintain a constant temperature during the process is estimated at h_{dg}=18.60 kWh_{th}/tonne of input feedstock [35].

Biogas produced at the plant is used in a gas engine of the power P_{CHP}=1,000 kW_{el} and efficiency η_{el}=0.40 and η_{th}=0.50. The operational costs for a biogas CHP plant include running costs (maintenance, salaries and other diverse operational costs, *MSO*), while the cost/gate fee associated with the feedstock for biogas is not included in operational costs [72]. For the 1 MW_{el} biogas plant, the *MSO* was estimated at ca. 200,000 € per year [73].

After every 60,000 operating hours, the biogas engine goes for an overhaul that costs ca. 500,000 € [25]. The electricity produced in CHP is sold to the electricity grid, while excess heat is used in a nearby rendering plant. The heat demand of the rendering plant is many times higher than the heat currently supplied from the biogas CHP. To cover the total heat demand of the rendering plant, natural gas boilers are used. The selling price of high-grade heat from biogas plant, which sold to the nearby company, is classified information. Nevertheless, for the purpose of this study, that price was estimated at p_{exp}=2.0 €-Cent/kWh_{th} [22]. Also, the revenues of the biogas plant due to the received waste (the current gate fee) and the electricity sold to the grid are also confidential information.

3.2 Input data for power-to-gas integration

To find the potential for electricity production from PV and wind, the following coordinates were used: 45°47'56"N, 16°10'51"E. Characteristic values a_{PV} and a_{wind} at the location were obtained from PVGIS [74] and Renewable Ninja [75]. To investigate the impact of uncertainty in power generation, the model was studied through two subcases:

- Subcase A: Deterministic case in which no uncertainty in electricity production was taken into account.
- Subcase B: Robust case in which the uncertainty in electricity production is considered in the model. Deviation of the wind and PV power profile from the mean data at the location is set to 10%, since this proved to be the common value [66].

The specific investment costs for wind and PV installation were taken, on average, as 1,000 €/kW$_{el}$ for wind and PV installation, while *opex* for the PV plant represents 3% of *capex* per year and 1% for the wind farm [76]. The *capex* for additional biogas storage operating at atmospheric pressure is estimated at 180 €/m^3, with no significant *opex* required [77]. The *capex* and *opex* values for the upgrading unit, electrolyser and methanator are shown in Table 1. The specific electricity consumption (e) of these units includes both the electricity consumption of the unit itself and the power supply for instruments, valves and other peripherals [78].

Table 1 Input data for upgrading unit, electrolyser and methanator installation

Input parameters	Biogas upgrading (Pressure Swing Adsorption)	Electrolyser (Proton Exchange Membrane)	Methanator
e [kWh_{el}/Nm^3]	0.17 – 0.45 [26,38,56]	3.9 – 5.6 [38,60,79,80]	12.3 – 15.8 [60,81,82]
η [%]	84 – 96 [26,56]	60 – 80 [60,79]	55 – 85 [38,60,81]
capex [€/(Nm^3/h)]	3,200 – 4,500 [56]	(1,000 – 2,000 €/kW_{el}) 6,950 [83,84]	(650 – 660 €/kW_{el}) 6,250 [38,61]
OPEX [% of *CAPEX*/y]	4 [85]	3 [83]	10 [86,87]

The price of electricity on the day-ahead market was obtained from the Croatian Power Exchange (CROPEX) [88]. For 2019, the average price for electricity on the wholesale market was 4.93 €-Cent/kWh_{el}. In the case of importing electricity from the grid, the regulated component was added to the wholesale price (in Croatia it accounts for ca. 80% of the wholesale electricity price [89]), which resulted in a total average price of electricity equal to 8.87 €-Cent/kWh_{el}. In the case when excess electricity from the system is exported to the grid, a regulated component was not considered.

The heat released during methanation was estimated at between 1.6 and 2.1 $kWh_{th}/Nm^3(CO_2)$ [35], and in this study the average value of 1.9 was used. To estimate the economic viability of the proposed model, the *LCOE* and *LCORM* values were calculated for a period of 20 years and the discount rate of 5%, which are common values for these technologies [90].

3.3 Scenario analysis

In this study, three scenarios for P2G integration into an existing biogas plant were developed referring to Subcase A and Subcase B. The scenarios differ based on electricity demand and utilisation of biogas technology:

i) Scenario I – biogas is used in an existing CHP unit to produce heat and electricity; CO_2 after combustion is utilised with H_2 from electrolyser to produce e-CH_4 in the methanator.

ii) Scenario II – biogas is utilised with H_2 from electrolyser in methanator to produce renewable CH_4, without separating CO_2 and CH_4.

iii) Scenario III – biogas is fed to the upgrading unit to separate CO_2 and CH_4; the CO_2 stream is used in the methanator with H_2 from electrolyser to form e-CH_4, which is combined with the b-CH_4 stream from the upgrading to produce renewable CH_4.

To investigate the level of variable RES penetration and the capacity of the gas processing units in this model, the price of electricity purchased from the day-ahead market was increased by 10, 20, 30, 40 and 50% compared to average price from 2019. In the end, the levelized cost of renewable methane production was estimated by alternating the feedstock *GF*.

4 RESULTS AND DISCUSSION

This section presents the results of the analysis of the P2G concept integration into the biogas plant operating under a feedstock *GF* business model.

The first set of results is presented for the analysis performed under Subcase A, with no uncertainty included in the model, analysing the *LCOE* for wind and PV, hourly based operation of the system, assessed capacity of all energy units and economic analysis of renewable methane production at the location. The second set of results includes uncertainty in the model

(Subcase B), presenting the impact of robustness in electricity production on the total cost of the energy system.

The result figures presented in the manuscript are intended for biogas plant operators in order to quantify the techno-economic conditions of RES integration with the aim of achieving the profitable operation even in the post-subsidy period. The assessed capacities of photovoltaic and wind plants, electrolysers and methanators represent technical requirements for the integration of the P2G concept into the advanced operation of existing biogas plant. The level of the gate fee for a received substrate indicates at what level advanced biogas plants can produce renewable gas that is economically competitive with natural gas.

4.1 Subcase A

4.1.1 Cost of electricity production from variable energy sources

For wind electricity, the *LCOE* value was calculated at 6.4 €-Cent/kWh_{el} and for PV at 7.4 €-Cent/kWh_{el}, which are both in the range of data from previous literature [91], for wind 4.0-8.2 €-Cent/kWh_{el} and 3.7-11.5 €-Cent/kWh_{el} for PV. Based on the estimated potential for electricity production at the location, the capacity factor [92] for wind was estimated at 22% and 16% for PV. That explains why in this case study, the *LCOE* for wind was lower than that for PV.

4.1.2 Operation and capacity of energy units

The hourly based operation of electricity producing units to cover the electricity demand of renewable methane production in a typical winter and summer week of a year is shown in Figure 2.

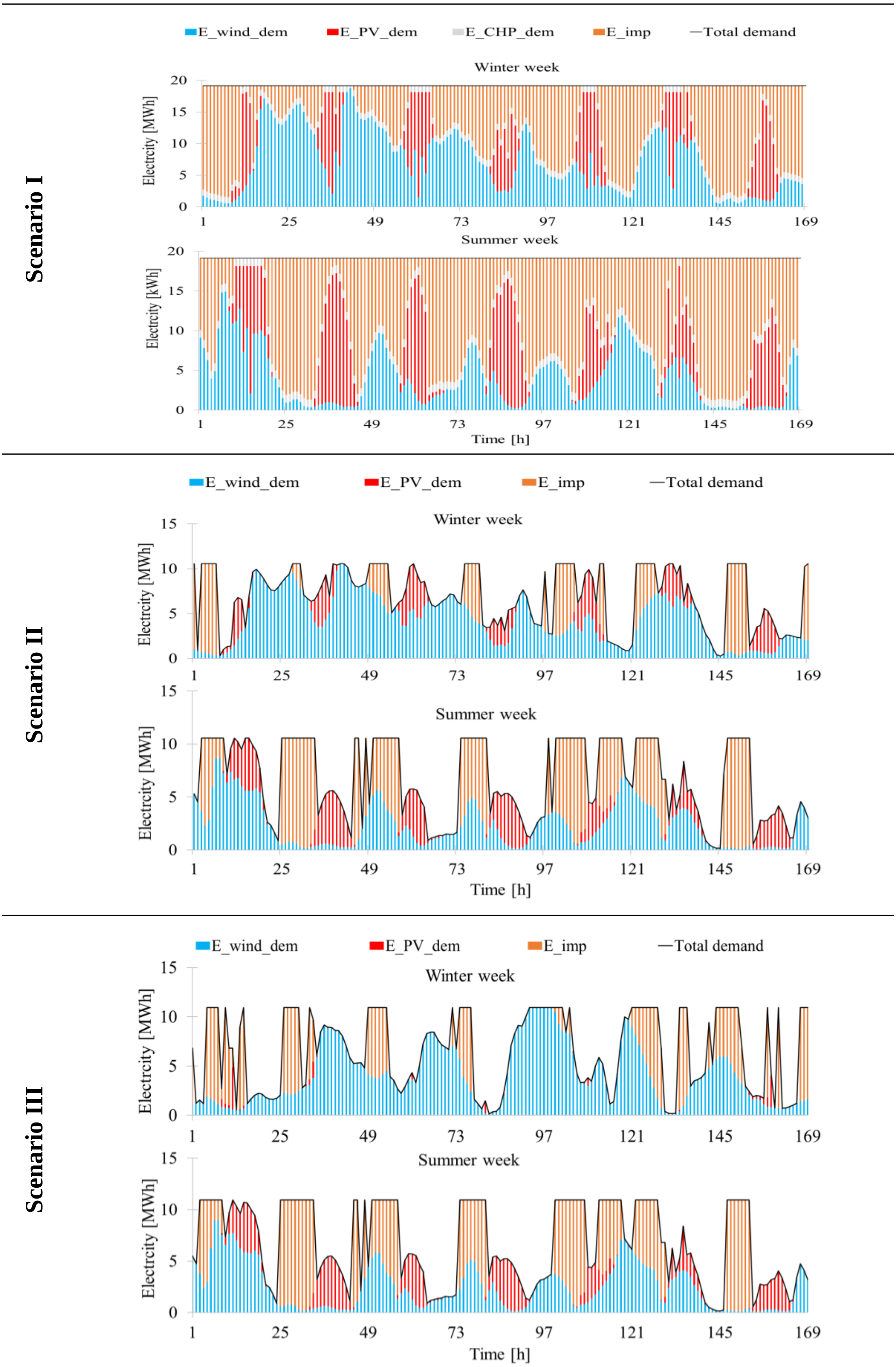

Figure 2: Hourly based operation of the system in a typical winter and summer week, Subcase A

Since the cost of electricity produced in the biogas CHP was lower than that for wind and PV (the assumption was that the investment in biogas CHP had been paid out before integrating P2G), the production of CO_2 from biogas CHP was constant (flat, like the total demand curve in Figure 2), which required immediate utilisation in the P2G concept.

The optimised capacity of external storage in Scenario I was equal to 0 m^3, while the capacity of additional storage in Scenarios II and III ranged between ca. 5,000 and 8,500 m^3 in the given electricity market conditions.

On a yearly basis, for the production of 36 GWh of renewable methane, the total electricity demand in Scenario I was estimated at 167.5 GWh_{el}, in Scenario II at 58.6 GWh_{el}, and in Scenario III at 59.8 GWh_{el}. The analysis showed that Scenario I cannot be feasible due to the extremely high electricity demand in the process and the low integration of the P2G concept in the biogas plant whose operation should be assisted by imported electricity from the grid. In more detail, results in Figure 2 showed the hourly-based operation of the system in two characteristic weeks in the studied year.

The electricity generated by the wind farm at the location in Scenario I accounted for ca. 18% of the total demand in the summer week, and ca. 37% of the total demand in the winter week. The PV plant at the location in Scenario I covered ca. 25% of the total demand in the summer week and ca. 15% in the winter week. The biogas CHP covered ca. 7% of the total demand over the year, while the rest (ca. 40-50% of the total demand) was covered by electricity imported from the grid. In both Scenario II and III, the penetration of wind and PV in the total electricity demand was very similar, ca. 35% of the total demand in the summer week and ca. 62% in the winter week for wind, and ca. 18% of the total demand in the summer week, and ca. 14% in the winter week for PV. In Scenario II and III, the electricity imported from the grid to cover the total demand for renewable methane production accounted for ca. 25-45%.

Optimised capacity of the wind and PV plant in the given electricity market conditions and for each scenario are shown in Figure 3.

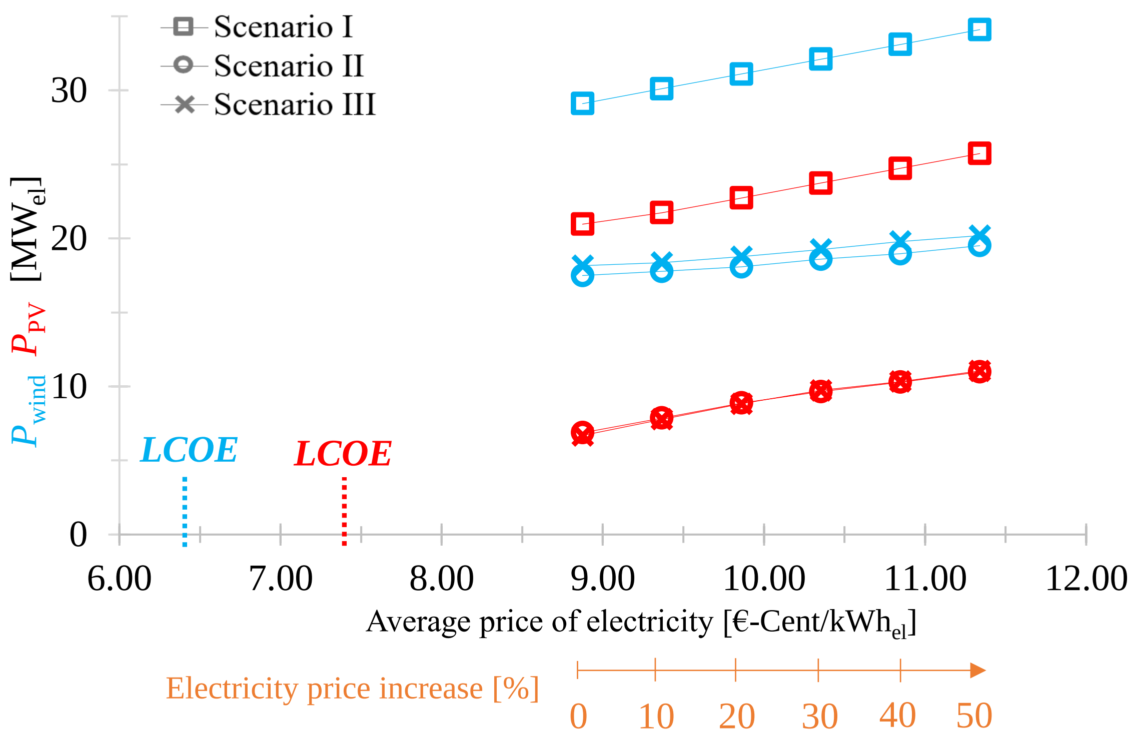

Figure 3: The impact of average electricity price on wind and PV capacity, Subcase A

As the market price of electricity increased, the penetration of variable RES became more important to cover the energy demand of the system. As can be seen in Figure 3, the potential for wind penetration in the system was significantly higher than that of PV, since the *LCOE* for wind was found to be lower than that for PV.

Results obtained by Scenario II and Scenario III were very similar in the given electricity market conditions. In Scenario II, the optimised capacity of the methanator was calculated at 650-730 Nm^3(e-CH_4)/h, while the capacity of the electrolyser was optimised in the range 920-1,000 Nm^3(H_2)/h. The capacity of the methanator in Scenario III is optimised to the value of ca. 230-270 Nm^3(e-CH_4)/h, while the biogas upgrading unit had an optimum capacity between 660-730 Nm^3(biogas)/h.

Based on the results of the optimisation, it was estimated that the capacity factor for the electrolyser ranged between 56% and 62%, while for the methanator, the capacity factor was assessed at ca. 57-63%. Using the developed model, it was found that for the production of 900-1,100 $Nm^3(H_2)$/h in the electrolyser which served in the methanation to produce 36 GWh per year of renewable gas (both e-CH_4 and b-CH_4), installation of a wind plant of ca. 18-20 MW_{el} and a PV plant of 6.5-11.0 MW_{el} was required.

In the *Audi e-gas* plant [38], to meet the electricity demand for producing 1,200 $Nm^3(H_2)$/h, which is used to produce 300 Nm^3(e-CH_4)/h, four wind turbines were installed, each of 3.6 MW_{el} capacity, in total 14.4 MW_{el}. The capacity factor for wind at this location of the biogas plant was estimated at 22%, while in Northern Germany it was significantly higher, ca. 40% [93].

Based on the model results and comparison with data obtained from the literature, it can be concluded that the developed model for P2G integration in the biogas plant could be applicable for estimating the capacity of variable RES at the location required for these processes.

4.1.3 Economic analysis of the energy system

In Scenarios II and III, the cost of electricity imported from the electricity grid to the system decreased from ca. $1.4 \cdot 10^6$ € (at an average electricity price of 8.87 €-Cent/kWh_{el}) to ca. $1.1 \cdot 10^6$ € when the electricity price increased by 50%. In Scenario I, the cost of imported electricity from the grid in the same range of prices was calculated to be much higher, between $7.4 \cdot 10^6$ and $9.3 \cdot 10^6$ €.

In Scenario II and Scenario III, it was estimated at ca. $1.1 \cdot 10^5$ € (at the electricity price of 8.87 €-Cent/kWh_{el}), and it increased by almost 200% when the electricity price increased by 50%. The higher revenue was achieved in Scenario I, between 2.8 and $4.5 \cdot 10^5$ €. In Scenarios

II and III, the revenue from heat sold to the nearby rendering plant was around $3.5 \cdot 10^4$ €, while in Scenario I, this figure was significantly higher, ca. $3.5 \cdot 10^5$ €.

The analysis showed that heat exported to the rendering plant accounted for ca. 12-25% of the overall revenue from selling the energy in Scenarios II and III, while in Scenario III the heat represented ca. 44-45% of the total revenue. As expected, Scenario I yielded higher revenue from selling the heat from the biogas CHP, but it also resulted in higher demand for importing electricity, as the amount of CO_2 used in the methanator was much higher than in Scenarios II and III.

All capital and operating costs in the system, costs and revenues from imported and exported electricity and revenues from the exported heat were counted, adding the feedstock *GF* as additional revenue according to Eq. (31). The sensitivity analysis took a variation of the feedstock *GF* from 0 €/tonne to -200 €/tonne, and the results are shown in Figure 4.

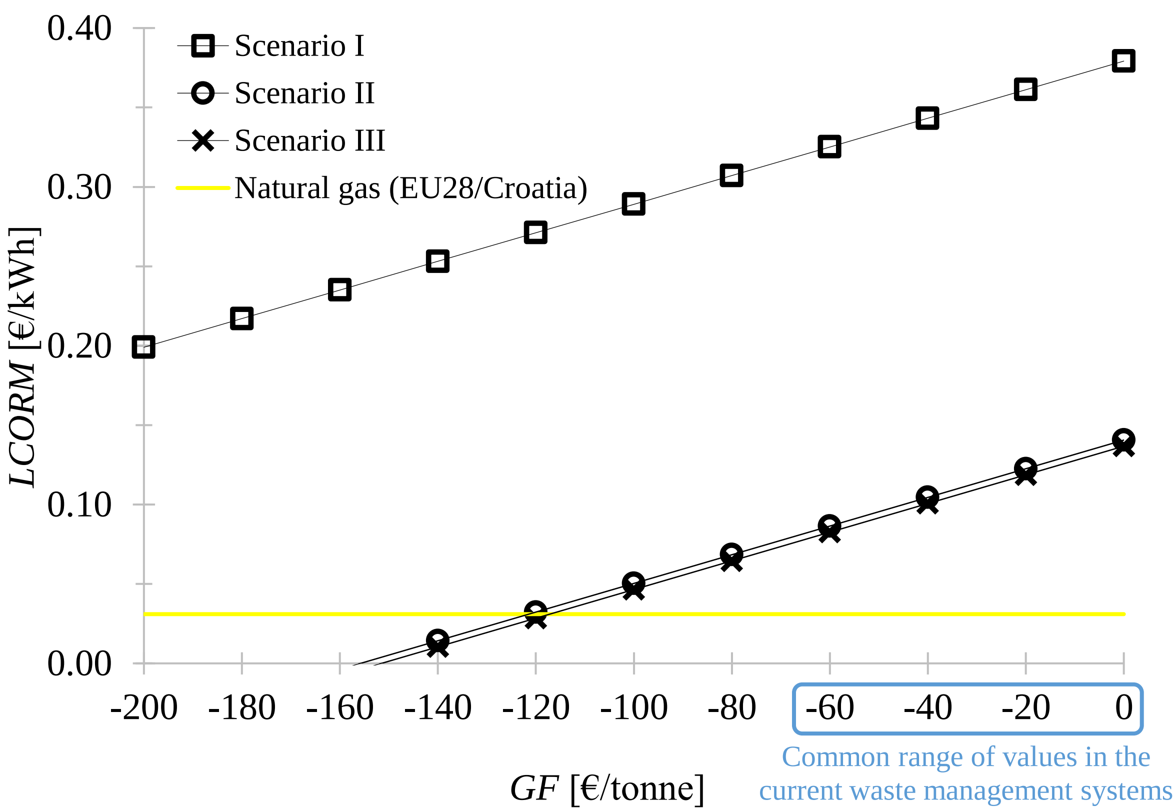

Figure 4: Sensitivity analysis of the feedstock *GF* variation on the *LCORM*

The *LCORM* in Scenario II and Scenario III fitted very close to each other, while the *LCORM* in Scenario I was significantly higher. As the (absolute) value of *GF* increases, the cost of renewable methane production decreases and contributes to the economic viability of the proposed energy system. In general, the levelized cost of SNG generation by P2G ranged between 0.08 and 0.60 €/kWh [32]. More precisely, the cost of renewable methane produced in P2G with the direct methanation of biogas was estimated at 0.24-0.30 €/kWh [94].

If the *LCORM* in Scenarios II and III reached the average price of natural gas for non-household consumers in Croatia (which is very close to average in the EU28, ca. 0.031 €/kWh [95]), the *GF* in the proposed system should be ca. -120 €/tonne. In Scenario I, the *GF* would need to be ca. -385 €/tonne to meet the average price of natural gas in Croatia/the EU28. The calculated values of *GF* in these scenarios are significantly higher than those reported for food waste/biowaste based biogas plants in the EU, for which the common *GF* values are between -40 and -50 €/tonne [96,97].

When the *LCORM* achieves the average natural gas price for household consumers in the EU (ca. 0.067 €/kWh [95]), the *GF* should become ca. -80 €/tonne, which is closer to common *GF* values in the biogas sector. One reason that biogas plants have not yet intensified their operation in the waste management system using biodegradable fractions and biowaste is that the fee for landfilling organic waste in Europe is still rather low, between -20 and -30 €/tonne [98]. However, since landfill is no longer prioritised as a waste management solution [99], it is expected that in future the biogas sector will take over the management of biodegradable organic waste, which will apparently result in *GF* values higher than the current ones.

Moreover, further liberalisation of the natural gas market in Europe and Croatia is expected in the coming years [100]. This could result in an increase of natural gas prices, which would contribute to greater penetration of renewable methane in the gas sector.

4.2 Subcase B

The impact of introducing uncertainty into the mathematical model using the gamma parameter in electricity production at the location, on the optimal economic results and the imported electricity from the grid is shown in Figure 5.

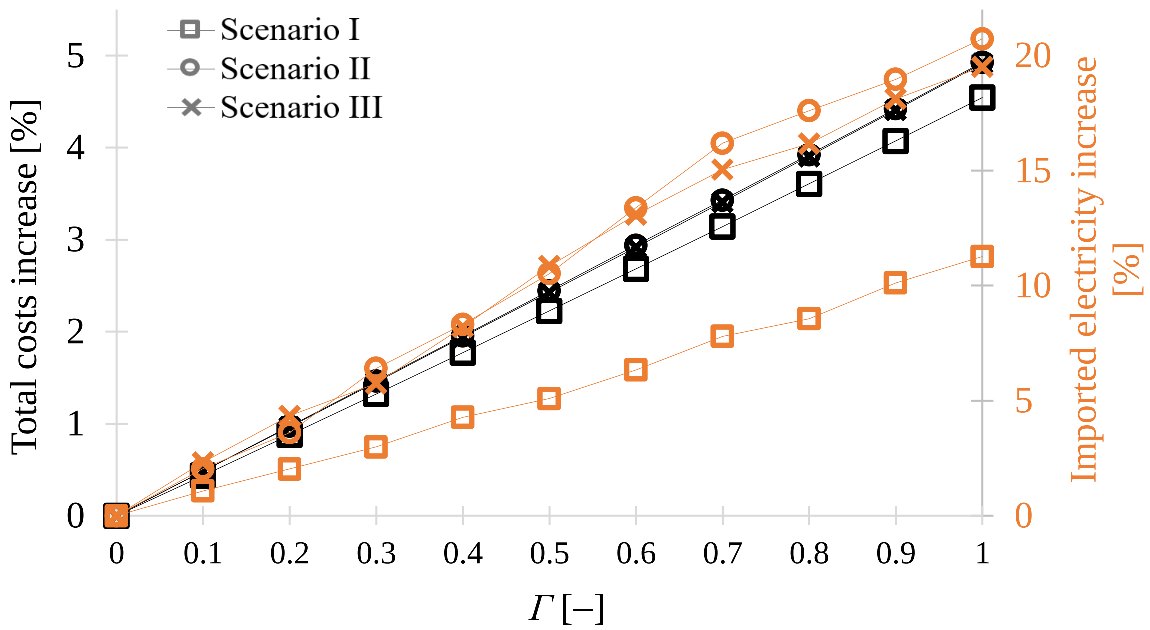

Figure 5: Increase in the total costs of the system operation and imported electricity in relation to robustness level

As presented in Figure 5, introducing uncertainty into electricity production resulted in a decrease in the economic benefits of the system and in an increase in the amount of electricity imported from the grid. When the robustness level met the most conservative case, the total costs increased by ca. 5% in all examined scenarios.

Regarding electricity import, the most conservative approach resulted in an increase of 11% in Scenario I, ca. 21% in Scenario II and ca. 20 % in Scenario III. Introducing uncertainty in Scenario I was shown to have a lower impact on the increase in the amount of imported electricity, compared to Scenario II and Scenario III. This was explained by the fact that the imported electricity in Scenario I constituted almost half the total electricity demand (Figure

2), while in Scenarios II and III, the energy systems relied more on electricity from wind and PV (also Figure 2), and therefore were more influenced by uncertainty in electricity production.

The increase in the system's robustness results in higher *LCOE* values for wind and PV [101], making the system more grid-dependent. In the present analysis it was reported that, for the most conservative case, the average increase in the *LCOE* at the location for wind was 14% and for PV 44%, compared to the case where no uncertainties were examined (Subcase A). In addition, the analysis showed that uncertainty decreased the load factor of renewable plants. On average, it was determined that the decrease for wind was from 22% to 16%, and for PV from 16% to 10%.

The overall impact of system robustness on the increase in *LCORM* (as presented in Figure 4, without uncertainties considered) was determined to be ca. 8-12% in Scenario I, ca. 3-32% in Scenario II and ca. 4-20% in Scenario III. Results indicated that the production of renewable methane in both Scenarios II and III was more affected by the uncertainties in electricity production than Scenario I. However, the cost of renewable methane production in both Scenarios II and III remained much lower than those in Scenario I, pointing to the conclusion that the concept of direct biogas methanation synergised with the feedstock *GF* in biogas production has a higher potential to be economically competitive with natural gas than CO_2 capture from flue gasses, utilised with renewable electricity [102].

From the technical point of view, the CO_2 utilisation concept presented in Scenario I has several shortcomings, the major one being the separation of relatively low concentrations of CO_2 from the large amounts of nitrogen in the flue gasses, which was not considered in this study but represents an important investment and operational factor in the process. It was determined that capturing post-combustion CO_2 at a biogas plant cannot be feasible in any case to the biogas upgrading process [103].

5 CONCLUSION

The robust mathematical model developed in this study was successfully tested on a real biogas plant, analysing key features of the implementation of the power-to-gas concept. Direct methanation of biogas has proven to be economically attractive option for the integration of power-to-gas concept driven by the PV and wind plant. About 60% of the total electricity demand to produce renewable methane can be obtained from variable RES, while the rest should be covered by the electricity from the grid.

The hypothesis of the study was successfully confirmed, as the feedstock gate fee significantly reduced the cost of renewable methane production, bringing additional viability to the plant operation. The research showed that the gate fee level for food waste below which the advanced operation of biogas plants becomes viable is around -120 €/tonne.

The analysis showed that the studied energy system becomes more grid-dependent and the cost of renewable methane production becomes higher if the uncertainty in electricity production from wind and PV at the location intensifies. The projections indicate that an increase in landfill gate fees for biodegradable waste, a liberalisation of the natural gas market and a reduction in investment costs for renewables (wind and PV plants) will eventually contribute to creating renewable methane that is economically competitive with natural gas.

In future research, the authors are inclined to study the integration of demand-response in the existing robust model, especially considering hydrogen production in the electrolyser and market prices.

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