Flexible power generation scenarios for biogas plants operated in Germany: impacts on economic viability and GHG emissions

Markus Lauer1,*, Martin Dotzauer1, Christiane Hennig1, Monique Lehmann1, Eva Nebel1, Jan Postel1, Nora Szarka1 and Daniela Thrän1,2

1DBFZ Deutsches Biomasseforschungszentrum gemeinnützige GmbH (German Biomass Research Centre), Torgauer Strasse 116, 04347 Leipzig, Germany
2UFZ Helmholtz-Zentrum für Umweltforschung (Helmholtz Centre for Environmental Research), Permoserstrasse 15, 04318 Leipzig, Germany

SUMMARY

Biogas plants enable power to be generated in a flexible way so that variable, renewable energy sources can be integrated into the energy system. In Germany, the Renewable Energy Sources Act promotes flexible power generation in biogas plants. Two existing biogas plants in flexible operation were analyzed with respect to economic viability and greenhouse gas (GHG) emissions to assess the feasibility of flexible operation. To do this, a biogas technology simulation model was developed to reproduce the technical design of both biogas plants and to link this design with twelve flexibilization scenarios. The evaluation of the economic viability is based on a discounting method of investment appraisal. For assessing the level of GHG emissions, the life cycle assessment method has been applied. The results show that the profitability of flexibilization is contingent upon premium payments promoting flexibility and direct sales resulting from a higher electrical efficiency of new or additionally installed combined heat and power units. Overall, with respect to profitability, the results of the flexible power generation scenarios are dependent upon the properties of the technical plant, such as its power generation and gas storage capacities. Relative GHG emissions from flexible biogas plants show significantly lower values than for referenced fossil gas–steam power stations. Among the various scenarios, the results reveal that the level of GHG emissions especially depends on the number of operating hours of the additional combined heat and power unit(s). The results of the analyzed biogas plants showed no direct correlation between GHG emissions and the economic benefits. Overall, a flexible power generation of biogas plants may improve the economic viability as well as result in lower GHG emissions in comparison with a conventional base load operation. © 2016 The Authors. International Journal of Energy Research published by John Wiley & Sons Ltd.

KEY WORDS

renewable energy; biogas; flexible power generation; economic analysis; life cycle assessment

Correspondence

*Markus Lauer, DBFZ Deutsches Biomasseforschungszentrum gemeinnützige GmbH (German Biomass Research Centre), Torgauer Strasse 116, 04347 Leipzig, Germany.
†E-mail: markus.lauer@dbfz.de

The copyright line for this article was changed on 29 September 2016 after original online publication.

This is an open access article under the terms of the Creative Commons Attribution-NonCommercial License, which permits use, distribution and reproduction in any medium, provided the original work is properly cited and is not used for commercial purposes.

Received 31 July 2015; Revised 4 April 2016; Accepted 8 June 2016

1. INTRODUCTION

The shift away from a fossil-based energy system towards a decarbonized and more sustainable supply of energy is particularly driven by the need to mitigate negative impacts on climate change [1,2]. As a consequence, Germany aims to reduce greenhouse gas (GHG) emissions by at least 80% (over 1990 figures) by 2050 through improved energy efficiency and the further development and use of renewable energy sources [3]. This brings along the
necessity of integrating large amounts of renewable energies, including variable renewable energy sources like photovoltaic and wind power [4].

However, generating electricity that increasingly relies on variable renewable energy sources requires technologies for balancing supply and demand, for example, flexible power plants, storage systems and demand-side management [5–12]. Biogas plants are one option to generate power in a flexible way [8], so that variable, renewable energy sources can be integrated into the energy system. For an appropriate flexible power generation of biogas plants, however, sufficient knowledge on technical options and investments in additional infrastructure are required. Since 2012, the German feed-in tariff system, the Renewable Energy Sources Act (EEG), has promoted the flexible generation of electricity by offering premium payments to stimulate investments in components that support demand-oriented energy generation in existing biogas plants [13]. So far, little is known about the economic and ecological impact of a flexible power generation of biogas plants on the energy system. In addition, results from gas-fired power plants and conventional combined heat and power units (CHPUs) are only partially transferrable to biogas plants (owing to endless natural gas storage capacities within the natural gas network).

The role of flexible biogas plants for electricity supply in a renewables-based energy system has already been assessed in several studies [7–9,14,15]. Hahn et al. [7] analyse flexibilization concepts of biogas plants, and Hahn et al. [9] examine the costs of a demand-oriented biogas supply and the impact on the biogas storage capacities required for flexible power generation. Most of the Hahn et al. [9] discussed concepts are based on a target-oriented feedstock supply and thus a controllable production of biogas. We, however, assume a constant gas production within the scope of this research because most of the biogas plants are currently operating with constant feedstock supply in Germany and a demand-oriented feedstock management is not state-of-the-art so far. Szarka et al. [8] describe technical concepts and legal conditions of bioenergy for demand-driven power generation. The economic feasibility and the profit maximization of biogas plants are analysed by Hochloff and Braun [14]. This study shows that the feed-in tariff system of the Renewable Energy Sources Act and the premium payment for flexibility related to it make flexible power generation of biogas plants economically feasible. Increasing the installed capacity by a factor of 3.3 (0.6 to 2 MW) achieves the best economic results. Hahn et al. [15] performed life cycle assessments (LCA) of different biogas plants supplying biogas in a demand-oriented way. They found that demand-oriented biogas supply reduces the need for biogas storage capacities for flexible power generation and results in lower environmental effects. However, a comprehensive study on the economic viability and GHG emissions from flexible biogas plants and a combination of these two aspects are missing.

Following, the objective of this paper is to determine the plant configurations, modes of operation and schedules of biogas plants that lead to the most feasible flexible power generation scenario when considering the incentives set by the German feed-in tariff system EEG. Therefore, this research aims at modelling technically feasible flexible biogas alternatives in Germany and at assessing and comparing them in terms of their economic profitability and GHG emissions. For this purpose the following sub-objectives are addressed:

- characterization of technical configurations of flexible biogas plants in a model
- determination of scenarios represented by different modes of operation and schedules
- simulation of scenarios and assessment of their profitability based on a discounting method of investment appraisal and GHG emissions based on the LCA method
- analysis and discussion of possible correlation between GHG emissions and profitability of flexible power generation scenarios.

2. METHODOLOGY

The methodology applied consists of three steps:

1. modeless the technical behaviour of flexible biogas plants and simulating scenarios
2. economic assessment and
3. evaluation of GHG emissions.

These steps are integrated in a modular system that includes technical configurations of the plants as well as economic and ecological parameters. In contrast to a monolithic simulation model, the modular approach allows mapping a large number of scenarios and an individual combination of model components. Data on biogas plants used in the calculations were provided by the plant operators and collected via a manufacturer’s survey.

In contrast to the methodology presented in [15], this paper uses an LCA approach to examine the GHG effects of flexible power generation in biogas plants. We look at the production of electrical energy and its overall GHG emissions where 1 kWh equals one functional unit. In contrast, Hahn et al. [15] use primary energy equivalents in their ecological assessment. We include the global warming potential as a main impact category. In addition to the global warming potential, Hahn et al. [15] also reflect on the impact caused by the categories acidification and eutrophication. While Hochloff and Braun [14] assess model plants, our research analyses two existing biogas plants and their specific technical requirements.

The economic assessment and LCAs are based on an integrated simulation model (Section 2.1). In the economic assessment, the profitability and payback period are determined using the equivalent annuity method (Section 2.2). The LCA compares the GHG emissions for each scenario within the defined system boundary based on the International Organization for Standardization norms 14040 and 14044 (Section 2.3).
2.1. Modelling

2.1.1. Model concept

The two selected biogas plants are transferred to a standardized scheme using an integrated simulation model consisting of plant configurations, modes of operation and schedules. Key parameters for this model are the CHPU energy balance, the filling level of the biogas storage and the fulfillment of heat demand.

Figure 1 provides an overview of the steps for assessing the various scenarios and thus identifying the best flexible power generation scenario concerning economic viability and GHG emissions, respectively. The conception of the technical modelling is presented next, while the economic and environmental analyses are described in detail in Sections 2.2 and 2.3.

2.1.2. Model calibration

Technical configurations are based on the status quo of two sample biogas plants. First, we compiled all key parameters of the sample biogas facilities. Based on previous power generation, we calculated the primary energy supply in terms of the biogas produced and set this for the particular plant. Then we recorded the installed capacity, electrical efficiency factors and the year the CHPU began operations. The size of the available gas storage capacities was also monitored.

2.1.3. Scope, definitions and assumptions

Within the scope of this paper, flexibility is defined as the ability of power-generating facilities to shift load temporarily. Biogas plants can be divided into two systems: the gas production based on microbial fermentation and the subsequent utilization of biogas for power and heat cogeneration. Both systems can be subject to a flexibilization. Hahn et al. [9] and Mauky et al. [16] show that a temporal variation in the feedstock supply and related biogas production can provide a certain flexibility. The focus of this paper is on a flexible power and heat production (with gas being produced at a constant rate).

In order to provide flexibility in this respect, it is important to have a sufficient margin between the rated capacity equivalent to the gas production and installed capacity. To achieve such a margin, the power generated over a certain period of time (rated capacity – $P_{\text{rated}}$) must be less than the potential power generation at nominal capacity over the same period of time (nominal capacity – $P_{\text{nom}}$). As the inverse of the capacity factor, we define the ratio between nominal capacity and rated capacity as the power quotient ($PQ$):

$$PQ = \frac{P_{\text{nom}}}{P_{\text{rated}}}$$ (1)

This quotient describes the potential for flexible power generation and will be used in this paper to assess flexible biogas concepts.

Generally, there are two fundamental types of energy production: base and peak load. Base load operation means the CHPUs run continuously at an assumed rate of 8000 full load hours (flh) per year. This type of energy production does not allow for flexible power generation but does generate control power.1 According to A. Ortner et al. [18], negative secondary control power (neg-SCP) is currently the most economical kind of control power for biogas plants in Germany. It is assumed that base load operation of CHPUs supports neg-SCP. Hence, to supply secondary control power (SCP), the technical ability of power provision over 12 h on workdays is necessary.

---

1Electric power for compensating unexpected deviations from generation and consumption of electrical energy to stabilize a frequency of 50 Hz in the grid [17]. Further details of the design of the German balancing power markets are shown for example in [17].
Peak load operation is defined as the intermittent operation of a CHPU that is substantially less than 8000 h per year. Peak load operation of CHPU provides additional power and heat besides the energy production of the base load CHPU.

Thus, peak load operation of CHPUs can be used to provide demand-driven schedules targeted for the European Power Exchange spot market (EPEX Spot SE). With the exception of a continuous power generation during the period of SCP (e.g. from 0800 to 2000 h), peak load operation cannot support neg-SCP.

The European Power Exchange spot market is an exchange for short-term electricity products in Germany, France, Austria, Switzerland and Luxembourg. Phelix, a product offered in the German and Austrian markets, is taken as a reference. Because this market has a day-ahead trading period, it is assumed that load shifting only takes 1 day for all schedules.

Figure 2 illustrates the price curves (daily mean) for electricity traded in Germany and Austria. Hourly prices fluctuate during the course of the day. Regardless of the year, the hours in the morning and in the evening are more...
expensive than at midday and during the night. The electricity generated by photovoltaic systems, especially during the summer, cuts prices at midday. At night, the demand for electricity becomes significantly lower, reducing the price of electricity. As a consequence, the course of the average daily price curves (Phelix) is very similar among the years and additional revenues from EPEX Spot SE have little effect. Those daily price curves are providing the basis for calculating schedules of flexible biogas plants (Figure 4).

In order to design schedules, it is necessary to calculate the daily operating hours of the peak load CHPU. The base load CHPU is set at 8000 flh. The remaining difference between the amount of biogas produced and the amount of biogas consumed by the base load CHPU is then used to run the peak load CHPU and to determine its operating hours. Thereby, the calculated biogas production is completely used by the CHPUs. In addition, the operating hours of the peak load CHPU(s) is set constant for each day of the year.

Next, we determined the most preferable time to generate power with regard to spot market revenues. In this investigation, we used ex post data for the EPEX Spot SE [19] to determine ideal schedules (Figure 4). We applied the method of daily price order to do this because it is a simple method for achieving above-average revenues. The number of possible operating hours is therefore assigned to the most expensive hours of a particular day. This method is used for all 365 days of a year to create a 24-h by 365-day schedule. One limitation of this method is that gas storage and heat provision cannot be implemented as boundary values. As a consequence, gas storage capacity and demand-orientated heat provision are considered in a downstream step during the synthesis of optimized schedules when the scenarios are compiled as a summary of the plant configurations, modes of operation and schedules.

The potential requirement of total gas storage capacity is calculated as the difference between the global minimum and maximum levels of modelled storage. Within the model, the course of the storage filling level is computed over 8760 h for 1 year. The additional gas storage capacity results then from the gross value of the optimized schedules minus the already installed storage capacity of the biogas plant in question. For increasing the gas storage capacity, only internal double membrane storages are taken into consideration. The calculation of the required gas storage capacity is based on energetic equivalents. For this purpose, the existing storage is converted from an installed volumetric capacity to a calorific value capacity using parameters such as the temperature, pressure, density and calorific value of the biogas in the gas storage. This approach shall reflect the operating conditions.

To verify whether the heat provided by an optimized schedule covers the indentured heat demand at any given hour, we needed to ascertain the type and amount of the heat required by external customers. Thereby, it is assumed that the heat demand and the heat load profiles correspond to the ones before the biogas plant has been operated in a flexible mode (pre-flexibilization status). Heat provision is measured on a monthly and annual basis by biogas plant operators, but load profiles of existing heat sinks are required on an hourly basis. They were therefore synthesized according to that in [20]. The calculation method was based on user-specific, statistically evaluated standardized load profiles, the region’s climate conditions and the demand identified for a certain year [21]. This synthesized load profile resulted in the amount of heat that must be produced by the biogas CHPU as a co-product. The heat production profiles were simultaneously calculated based on the optimized schedules. Comparing the

![Figure 4](image-url)
hourly heat demand and the heat provision using optimized schedules determined the potential requirement of additional heat storage units.

The two sample biogas plants are using flexible operation since 2013, which has been applied as reference year for data collection. The underlying data for gas and electricity production, heat demand, electricity spot market and so on have a temporal resolution of 1 h. This resolution has been chosen because electricity spot market prices are only available on an hourly basis. However, in order to reflect seasonal variations of heat as well as electricity demand, the technical modelling is carried out for 1 year. The calculations are implemented by using several MS Excel spreadsheets.

2.1.4. Scenarios

With these assumptions, different plant configurations, modes of operation and schedules are combined in scenarios, which are then analysed with respect to economic viability and GHG emissions.

First, the amount of additionally installed power-generating capacity is considered, which is reflected by the plant configuration. Here, status quo defines the basic configuration of the existing plant, and additional capacity characterizes the virtually extended plant configuration with increased power-generating capacity or electrical efficiency due to additional or replaced CHPU. Then the mode of operation was looked at, which can be either referred to as semi-flexible or fully flexible. In the semi-flexible mode, the power generation of the CHPU is separated into base and peak load. At least one CHPU generates power in base load operation, and the remaining CHPU(s) are in peak load operation. In the fully flexible mode, the entire power generation is in peak load. Because of higher electric and thermal efficiencies, CHPU(s) are operating in full load [22]. The different plant configurations and modes of operation including the pre-flexibilization status are visualized in Figure 3.

By combining these two parameters, four different variants are produced (compare Table I). Based on these variants, specific schedules for hourly power generation were synthesized and blended with the boundary conditions for storage capacities (Figure 4). We identified two main categories of schedules, namely, fixed and daily-optimized schedules. Daily-optimized schedules are optimized on a daily basis and fixed schedules on a yearly basis. High tariff and double hump belong to the category of fixed schedules. Double hump schedules consist of two periods per day operated in peak load.

As a result, seven scenarios combining different plant configurations, modes of operation and schedules were created (compare Table I), based on which the economic and ecological assessments have been performed. To better compare and understand the flexibility requirements, a pre-flexibilization status was defined as a reference scenario.

2.1.5. Description of sample biogas plants

Biogas Plant A went into operation in 2004. At the time, the plant consisted of two CHPU with a total electrical capacity of 950 kWel. It had a non-flexible mode of operation. Capacity was increased by adding another CHPU, which provided base load energy, and operation shifted in 2013 to a semi-flexible mode of operation (Table II). Biogas Plant A is also connected to an existing local heating network.

Biogas Plant B’s flexibility strategy differs to that of biogas Plant A. The installed power of biogas Plant B was much lower before flexibilization (250 kWel), and the additional CHPU, which enables flexible operation, is used to generate power during peak load hours (Table III). The excess heat is used in a wood-drying facility that is directly attached to the plant. Unlike the local heating network connected to biogas Plant A, this heat sink can be supplied at any time. Moreover, in order to increase efficiency, the existing CHPU was replaced in 2013 by a CHPU with a higher electrical efficiency for the same installed capacity (CHPU 1e).

2.2. Economic assessment

The sample biogas facilities were analysed with regard to the profitability and payback period for the investment in flexible operation. The economic assessment is based on the equivalent annuity method (a discounted investment calculation). The advantage of the annuity method over other, somewhat simplified, capital budgeting methods, such as cost and profit comparison or accounting rate of return, is that the time value of money can be taken into account [23]. This allows modelling future cash flows and, thus, achieving more reliable results about whether a project will pay off in the future or not. The annuity method describes the equal annual gain or loss of a particular investment. For the calculation of the annuity (A), the net present value (NPV) of an investment, that is, the sum of the present values of all investment-related cash inflows and outflows, is spread over the period under consideration in equal cash flows per period [23]. According to the authors in [23,24], the NPV and the annuity are explained in Eqns (2) and (3):

\[
NPV = \sum_{t=0}^{T} \frac{N_t}{(1+i)^t} \tag{2}
\]

where \(T\) is project lifetime, \(N_t\) is net cashflow in the year \(t\) and \(i\) is discount rate.

\[
A = NPV \times AF \tag{3}
\]

where \(AF\) is annuity factor. The \(AF\) can be equated as Eqn (4):

\[
AF = \frac{[(1+i)^{1+i}]}{[(1+i)^t - 1]} \tag{4}
\]

Investing in a flexible mode of operation is
Flexible power generation scenarios for biogas plants

M. Lauer et al.

Table I. Scenarios based on plant configurations, modes of operation and generated schedules.

| Plant configuration | Mode of operation | Schedule | Scenario |
|---------------------|-------------------|----------|----------|
| Status quo          | Semi-flexible     | Current schedule | SQ-SF-CURRENT SCHEDULE |
|                     | Semi-flexible     | Double hump | SQ-SF-DUAL HUMP |
|                     | Semi-flexible     | Optimized daily | SQ-SF-OPTIMIZED DAILY |
| Additional capacity | Semi-flexible     | Optimized daily | SQ-FF-OPTIMIZED DAILY |
|                     | Semi-flexible     | Optimized daily | AC-SF-OPTIMIZED DAILY |
|                     | Semi-flexible     | High tariff | AC-FF-OPTIMIZED DAILY |

Table II. Description of Biogas Plant A including operating hours and technical details of the CHPU.

| Biogas Plant A | Primary energy (Qp) per day = 51.1 MWhp d⁻¹ |
|----------------|-------------------------------------------|
| Status quo     | Gas storage = 11.6 MWhp (22.6% of Qp per day)/3500 m³ |
|                 |                                          |
| Mode of operation | CHPU 1 | CHPU 2 | CHPU 3 | CHPU 4 | Power |
| (scenario)      | kWel  | kWel  | kWel  | kWel  | generation |
| Status quo      | 380   | 570   | 250   | 550   | per year |
| semi-flexible   | 7226  | 7226  | 7226  |       | 0 m³     |
| Status quo      | 0 m³  | 0 m³  | 0 m³  | 0 m³  | 0 m³     |
| fully flexible  | 2004  | 2009  | 2013  | 2013  | 0 m³     |
| Additional capacity | Peak load | Base load | Base load | Base load |
| semi-flexible   | 1358  | 8000  | 8000  | 8000  | 0 m³     |
| Status quo      | 7076  | 6988  | 7409  | 7142  | 1540 m³  |
| fully flexible  | 0 m³  | 0 m³  | 0 m³  | 0 m³  | 0 m³     |
| Additional capacity | Peak load | Base load | Base load | Base load |
| semi-flexible   | 4081  | 4081  | 4081  | 4081  | 9404 m³  |
| Status quo      | 4081  | 4081  | 4081  | 4081  | 6394 m³  |
| fully flexible  | 0 m³  | 0 m³  | 0 m³  | 0 m³  | 0 m³     |

CHPU, combined heat and power unit; flh, full load hour; kWep, kilowatts of electric capacity; MWhp, megawatt hours of primary energy; MWhq, megawatt hours of electrical energy; ηel, electrical efficiency.

economically feasible when the annuity is greater than, or equal to, zero, implying the investment would be beneficial [23]. For a further evaluation of the return of the investment, the discounting payback period has been determined. It defines the time period until the initial investment including interest will give returns [23].

In addition to data from the biogas plant operators regarding their investments in the facilities, several assumptions were made to determine the economic viability of flexible biogas installations (Table IV). Usually, only the cash inflows and outflows related to the flexible operation of a biogas plant are taken into account. Of the flexible biogas facilities sampled, cash inflows were generated by receiving fixed payments through the feed-in tariff system 3 for operating the biogas plant in a flexible mode and for selling the additionally produced electricity on the electricity exchange EPEX Spot SE. Additional EPEX Spot SE revenues were defined as the difference between real EPEX Spot SE revenues and the monthly average price on the EPEX Spot SE. Revenues from providing secondary control power were also considered. Flexibilization meant that revenues from the provision of SCP were lower than before flexibilization was introduced, when the higher base load share was higher. Cash outflows are expenses for biogas plant components, such as the CHPU, gas and heat storage facilities, periodic maintenance and other expenses like insurance [26]. Consumption-related expenses, mainly referring to expenses for the feedstock [26], were not taken into account because total amount of biogas production was the same for each of the scenarios. Thus, the volume of biomass input and associated consumption-related expenses were the same. Because biogas plants only receive a fixed payment over a period of 10 years to operate flexibly, the period under consideration was based on that funding criterion. Table IV provides an overview of the most relevant assumptions.

2.3. Life cycle assessment

The LCA was performed for the entire production chain including the cultivation of the feedstock, the transport systems, the biogas production and the final energy generation (system boundary, Figure 5). The modelling used the International Organization for Standardization norms 14040 and 14044 [27,28], a standard for assessing
potential environmental impacts. The calculation used the unit kg CO$_2$e kWh$^{-1}$ (ratio of carbon dioxide equivalents and kWh electrically), whereby 1 kWh el equaled one functional unit. The emissions were calculated for the different scenarios of the sample biogas plants A and B (Table I) with the current perspective referring to the year 2013. The global warming potential was the main impact category examined. The software UMBERTO 5.6 (ifu Hamburg GmbH, Hamburg, Germany) was used to calculate the LCA, and inventory data were taken from the Ecoinvent 2.2 database [29,30] and from questionnaires that were handed out to the operators of the sample biogas plants. GHG emissions from fertilizer, the production of seeds for cultivation, fuel consumption and electricity were also taken into account in the calculation. GHG emissions resulting from the infrastructure of the plant (e.g. buildings) were outside the scope of the assessment. Losses of methane of the fermenter (diffuse emissions) and of the CHPU were taken into account for each scenario, 1.0 and 0.5% p.a., respectively, according to that in [31]. Because of the simultaneous production of electricity and heat (multi-output process), it was necessary to split the resulting emissions and assign them to the corresponding energy category. To do this, we applied the exergy allocation method. This principle takes the different thermodynamic valency of electricity and heat into account when assigning the emissions to the main products of

### Table III. Description of Biogas Plant B including operating hours and technical details of the CHPU.

| Biogas Plant B | Primary energy (Q$_p$) per day = 18.9 MWh$_{hp}$ d$^{-1}$ | Gas storage = 6.6 MWh$_{hp}$ (35.1% of Q$_p$ per day)/1740 m$^3$ |
|----------------|---------------------------------------------------------------|---------------------------------------------------------------|
| Mode of operation (scenario) | CHPU 1 | CHPU 2 | CHPU 1* |
| Status quo | Power generation per year | Additional gas storage | Additional heat storage |
| semi-flexible | 250 kW$_{el}$ | 550 kW$_{el}$ | 250 kW$_{el}$ |
| η$_{el}$ = 38% | 2010 | 2013 | 2013 |
| Status quo | Base load | Peak load | 2704 MWh$_{el}$ | 78 m$^3$ | 0 m$^3$ |
| fully flexible | 8000 flh | 1280 flh | |
| Additional capacity | Peak load | Peak load | 2832 MWh$_{el}$ | 2657 m$^3$ | 23 m$^3$ |
| semi-flexible | 3541 flh | 3541 flh | |
| Additional capacity | Peak load | Base load | 2810 MWh$_{el}$ | 152 m$^3$ | 0 m$^3$ |
| fully flexible | 1473 flh | 8000 flh | |
| CHPU, combined heat and power unit; flh, full load hour; kW$_{el}$, kilowatts of electric capacity; MWh$_{hp}$, megawatt hours of primary energy; MWh$_{el}$, megawatt hours of electrical energy; η$_{el}$, electrical efficiency.

### Table IV. Assumptions for the economic assessment.

| Parameter | Assumption |
|-----------|------------|
| Year of flexible mode of operation | 2013 |
| Period | 10 years (according to the period of feed-in tariff payment) |
| Cash outflows | |
| Share of equity | 20.0% |
| Interest on equity | 6.0% |
| Share of debt | 80.0% |
| Interest on debt | 5.0% |
| Weighted average cost of capital | 5.2% |
| Capital-related rate of price increase | 1.0% |
| Operation-related rate of price increase | 2.0% |
| Other rate of price increase | 2.0% |
| Insurance and administration expenses | 1.0% of initial investment |
| Additional staff expenses | 28 €/h (0.5 h/day) |

(Continued)
Table IV. (Continued)

| Parameter | Assumption |
|-----------|------------|
|           | Cost function according to that in [42]: |
|           | $I_{\text{CHPU}} = (4500 \times \frac{P_{\text{inst}}}{C_0})^{0.275} \times P_{\text{inst}}$ (5) |
| $I_{\text{CHPU}}$ | investment for additional CHPU [€] |
| $P_{\text{inst}}$ | installed capacity [kW el] |
| Overhaul expenses for additional CHPU | 15.0% of investment in the CHPU |
| Other overhaul expenses | 2.0% of initial investment |
| Maintenance expenses CHPU | Cost function depending on the operational performance and number of starting sequences per year: |
| $C_{\text{mainCHPU}} = I_{\text{CHPU}} \times P_{\text{inst}} \times \text{flh} \times f_{\text{main}}$ (6) |
| $C_{\text{mainCHPU}}$ | = maintenance expenses CHPU [€ a$^{-1}$] |
| flh | Full load hours [h a$^{-1}$] |
| $f_{\text{main}}$ | Maintenance factor |
| $>4000$ flh and $<400$ starting sequences | $1.56 \times 10^{-3}$ |
| $>4000$ flh and $>400$ starting sequences | $1.69 \times 10^{-3}$ |
| $<400$ flh and $<400$ starting sequences | $1.88 \times 10^{-3}$ |
| $<400$ flh and $>400$ starting sequences | $2.03 \times 10^{-3}$ |
| Other maintenance expenses | 2.0% of initial investment |
| Investment in gas storage facility (double membrane storage) | Cost function according to data of manufacturers: |
| $I_{\text{GSF}} = (2500 \times \frac{V_{\text{gas}}}{C_0})^{0.6} \times V_{\text{gas}}$ (7) |
| $I_{\text{GSF}}$ | Investment in gas storage facility [€] |
| $V_{\text{gas}}$ | Gross volume [m$^3$] |
| Investment in heat storage facility | Cost function according to a price inquiry: |
| $I_{\text{HSF}} = (6 \times \frac{V_{\text{heat}}}{C_0})^{0.21} \times V_{\text{heat}}$ (8) |
| $I_{\text{HSF}}$ | = investment for heat storage facility [€] |
| $V_{\text{heat}}$ | Gross volume storage [m$^3$] |
| Cash inflows | |
| Sale of electricity | Revenues above annual average price EPEX Spot SE (2013: 37.78 € MWh$^{-1}$) [19] |
| Feed-in tariff payment | Premium payment for direct sales (contains annual average price EPEX Spot SE) and premium payment for flexibility (PF) [43] |
| $PF = (P_{\text{eil}} \times CA \times 100 \text{ ct Euro}^{-1}) (P_{\text{pp}} \times 8760 \text{ h})^{-1}$ (9) |
electricity and heat [32]. The nutrients of the digestates could substitute for mineral fertilizer. Accordingly, the system received credit for preventing GHG emissions through the production of mineral fertilizer. The credit was calculated on the basis in [33]. Table V provides an overview on the LCA assumptions of the feedstocks used by biogas plants A and B.

As part of the current perspective, the emissions of 1 kWh\textsubscript{el} within the system (Figure 5) were compared with fossil references (for both plants and the scenarios). For every schedule, the emissions, based on 1 kWh\textsubscript{el} (functional unit), were compared with a gas–steam power station and a coal-fired power station. Both types of fossil power stations are able to offer flexibility. We assume that if biogas plants switch to a flexible mode of operation, they no longer compete with lignite or nuclear power plants for base load functionality but rather compete with other flexibly run power plants like natural gas or coal-fired units. As a consequence, flexible biogas plants act as a substitute for flexible fossil power stations.

3. RESULTS

3.1. Economic assessment of biogas plant A

Figure 6 (and Table A.1 in detail) shows the results of the economic analysis of biogas Plant A with regard to the profitability and discounting payback period of the different scenarios. It can be seen that the preferred plant

![Diagram](Figure 5. System boundary of the life cycle assessment. CHPU, combined heat and power unit; CH\textsubscript{4}, methane.)
configuration is the one where there is an increase in total installed electric capacity (additional capacity). Moreover, semi-flexible power generation is recommended because of overall annual gains and the shortest payback periods. Even though there is only a marginal difference in the profitability and discounting payback period of daily-optimized and fixed schedules, schedules that are optimized on a daily basis are preferred.

In order to assess the impact that the degree of flexibilization has on profitability, all status quo scenarios and, hence, all additional capacity scenarios were evaluated and compared with the pre-flexibilization status. The scenarios SQ-FS-CURRENT SCHEDULE, SQ-FS-DOUBLE HUMP and SQ-FS-OPTIMIZED DAILY with a status quo plant configuration are economically feasible. A common attribute of the profitable scenarios is that they all operate on a semi-flexible basis. The discounting payback period ranges from 6.6 to 7.3 years. Our analysis reveals that the economic viability of the scenarios considered is mainly based on the premium payments for flexibility and on direct sales received as part of the feed-in tariff system. Additional revenues obtained through the electricity exchange EPEX Spot SE for demand-oriented power generation are of minor significance. Investment in additional CHPUs is an overriding expenditure in contrast to pre-flexibilization operation. One drawback of demand-oriented power generation is that there are lower revenues when providing SCP, which can only be fully supplied as part of a base load electricity supply. Among the economically favoured scenarios, additional revenues can be generated through EPEX as part of the scenarios SQ-FS-DOUBLE HUMP and SQ-FS-OPTIMIZED DAILY because of an optimization of the schedules. Because of additional EPEX profits, the difference between a fixed schedule (SQ-FS-DOUBLE HUMP) and daily optimization (SQ-FS-OPTIMIZED DAILY) amounts to 1.5 € a⁻¹. The SQ-FF-OPTIMIZED DAILY scenario is the least profitable with an annual loss of −81.6 € a⁻¹. This is due to the fact that, compared with pre-flexibilization operation, the additional profits from EPEX (8.5 € a⁻¹) do not offset the lack of revenue from SCP (−93.4 € a⁻¹).

When the installed capacity was increased in relation to the status quo scenarios, various effects on the average annual gain or loss were identified (Figure 6). For example, in scenario AC-SF-OPTIMIZED DAILY, a higher annual gain of about 52.1 € a⁻¹ was achieved compared with SQ-FS-OPTIMIZED DAILY. This corresponds to a difference of 37.6 € a⁻¹. Here, the lowest discounting payback period of 6.3 years was achieved among all observed scenarios. As a result, the level of the additional premium payment for flexibility, as well as an additional premium payment for direct sales, was positively affected by an

| Category                        | Element          | Value  |
|---------------------------------|------------------|--------|
| Transport distance (km)          | Grass silage     | 2      |
|                                 | Grain whole-plant silage | 2 |
|                                 | Maize whole-plant silage | 3 |
|                                 | Solid manure     | 2      |
| Feedstock fractions (mass) (%)  | Grass silage     | 10     |
|                                 | Grain whole-plant silage | 13 |
|                                 | Maize whole-plant silage | 45 |
|                                 | Solid manure     | 32     |

Figure 6. Results of the economic assessment of demand-oriented power generation by biogas plant A in various scenarios, shown as an annual gain or loss and discounting payback period. SQ, status quo; AC, additional capacity; SF, semi-flexible; FF, fully flexible; CS, current schedule; DH, double hump; OD, optimized daily; HT, high tariff.
increase in installed capacity of the CHPU. However, the evaluation shows that this only applies to scenarios with a semi-flexible mode of operation when considering biogas Plant A. Scenario AC-FF-OPTIMIZED DAILY with fully flexible operation results in an annual loss of $-57.7 \, \text{k€} \, \text{a}^{-1}$. This is especially due to a lack of revenues from the sale of secondary control power ($-93.4 \, \text{k€} \, \text{a}^{-1}$). Additional EPEX profits and revenues from SCP can both be realized as part of the scenario AC-FF-HIGH TARIFF. In every scenario, except the AC-FF-HIGH TARIFF scenario, revenues from neg-SCP were calculated for the entire capacity of all base load CHPUs. All CHPUs in the AC-FF-HIGH TARIFF scenario operate in peak load while simultaneously providing neg-SCP during the high tariff time period (HT) on workdays from 0800 to 2000h. The power generation of all CHPUs results in a lower annual gain of $30.3 \, \text{k€} \, \text{a}^{-1}$ over pre-flexibilization operation. Furthermore, additional revenues from EPEX are comparatively high during the aforementioned period ($26.8 \, \text{k€} \, \text{a}^{-1}$). However, because additional gas and heat capacities are needed in scenario AC-FF-HIGH TARIFF (leading to above-average capital-related expenses), this scenario is not economically feasible and has an average annual loss of $-1.5 \, \text{k€} \, \text{a}^{-1}$.

### 3.2. Economic assessment of biogas plant B

Analysing biogas Plant B in terms of the profitability and discounting payback periods of the different scenarios leads to results that deviate from biogas Plant A (Figure 7, Table A.1). Firstly, with the exception of scenario AC-FF-HIGH TARIFF, all payback periods are longer than in the biogas Plant A scenarios. These range from 8.0 to 9.7 years. Secondly, among the status quo scenarios, fully flexible operation (SQ-FF-OPTIMIZED DAILY) is more economically feasible than semi-flexible power generation such as in scenarios SQ-FS-CURRENT SCHEDULE, SQ-FS-DOUBLE HUMP and SQ-FS-OPTIMIZED DAILY. The annual gain can be improved by applying optimized schedules such as a fixed schedule and a daily-optimized schedule as in the scenarios SQ-FS-DOUBLE HUMP and SQ-FS-OPTIMIZED DAILY. The difference between both kinds of schedule optimization methods is, however, marginal with $0.4 \, \text{k€} \, \text{a}^{-1}$ in annual gains. Compared with biogas Plant A, scenario SC-SF-DOUBLE HUMP is more economically feasible than scenario SC-SF-OPTIMIZED DAILY mainly because of plant-specific parameters. The gas storage capacity of Biogas Plant A is sufficient for fixed (SC-SF-DOUBLE HUMP) as well as for OPTIMIZED DAILY schedules (SC-SF-OPTIMIZED DAILY). However, a higher gas storage capacity is needed for biogas Plant B in order to implement scenario SC-SF-OPTIMIZED DAILY over SC-SF-DOUBLE HUMP. This results in a smaller annual gain because of the need for a comparatively large CHPU during peak load generation (Figure 7).

Because of a higher electrical efficiency of a CHPU during peak load generation, revenues can increase significantly, especially in fully flexible operation (SQ-FF-OPTIMIZED DAILY). The ratio between peak and base load generation (PQ) is comparatively high; therefore, the loss in revenues from SCP does not have a significant effect on the overall results. When the CHPU is replaced by a unit with higher electrical efficiency (AC-SF-OPTIMIZED DAILY), the annual gain decreases to $1.8 \, \text{k€} \, \text{a}^{-1}$. One reason for this is the level of the premium payment for flexibility that is not affected by this increase in efficiency. Similar to biogas Plant A, scenario AC-FF-OPTIMIZED DAILY shows an average annual loss, while scenario AC-SF-OPTIMIZED DAILY generates a profit. Fully flexible power generation means that the volume of gas storage has to be higher than for semi-flexible operation, and this affects capital-related expenses. In scenario AC-FF-OPTIMIZED DAILY, the increase in capital-related expenses amounts to $6.1 \, \text{k€} \, \text{a}^{-1}$ compared with AC-SF-OPTIMIZED DAILY. Overall, there is evidence that, among all scenarios, the capital-related and operation-related expenses make up the highest share of total expenses.

![Figure 7](image-url)
Scenario AC-FF-HIGH TARIFF generates the highest profit of 28.1 k€ a⁻¹ for all scenarios. While revenues from the premium payment for flexibility are lower than in other scenarios, this scenario becomes profitable because of additional revenues from the premium payment for direct sales, comparatively higher revenues from the provision of secondary control power and comparatively low operation-related and capital-related expenses (Figure 7).

Merely replacing the CHPU with one that has a higher electrical efficiency showed no improvement in the plant’s profitability. It also showed that a fully flexible mode of operation is more economically feasible. Fixed schedules in status quo and additional-capacity plant configurations are recommended owing to higher profitability and lower discounting payback periods.

### 3.3. Life cycle assessment

The results of the analysis of biogas Plant A are given in Figure 8. The scenarios with a status quo plant configuration show the highest GHG emissions. Installing the additional CHPUs increases the overall efficiency of biogas Plant A. As a consequence, the scenarios with an additional capacity configuration achieve the best results. Generally, GHG emissions are influenced by the electrical efficiency of the CHPUs and their operating hours: the higher the efficiency, the lower the emissions. A relative low number of operating hours of the CHPUs generates a low electricity output, which negatively influences the level of GHG emissions. Therefore, semi-flexible operation is recommended for biogas Plant A owing to a higher number of operating hours of the more electrically efficient CHPU.

Calculations for biogas Plant B provide similar results to biogas Plant A (Figure 8). Once again, additional-capacity plant configuration decreases GHG emissions (scenarios AC-FF-OPTIMIZED DAILY and AC-FF-HIGH TARIFF) compared with semi-flexible power generation in the status quo configuration. Deviating away from the results of biogas Plant A, the scenario SQ-FF-OPTIMIZED DAILY achieves lower GHG emissions than scenario AC-SF-OPTIMIZED DAILY. Hence, in the case of biogas Plant B, the mode of operation is the main driver rather than the plant configuration. Biogas Plant B uses the new CHPU 1 for peak instead of base load power generation, whereby the benefit from a higher electrical efficiency only applies to peak load generation. Therefore, the lowest GHG emissions for Plant B can be observed in scenario AC-FF-HIGH TARIFF because it has the longest operating hours of the new CHPU.

The aforementioned assessment shows that flexible power generation from biogas plants, as shown for both plants A and B, is linked to lower GHG emissions compared with the aforementioned fossil reference plants (Figure 8). GHG emissions depend on the number of operating hours of the additional CHPU with higher electrical efficiency. This is why plant configuration AC, with higher levels of electrical output and a constant rate of gas production, achieves the best GHG emission results in most cases. On the whole, the results also imply that GHG emissions are not influenced by schedules because of the constant operating hours within the modes of operation.

![Figure 8](image-url)
4. DISCUSSION

4.1. Methodical limits

The chosen method reduces the complexity of the real world and thus simplifies the interplay of various factors when assessing flexible biogas installations. One limitation of this investigation is that a simulation model, unlike an optimization model, is only able to compare different scenarios. Therefore, we can identify the best scenario for each biogas plant, but the results for the best scenario could deviate from the optimum when using an optimization model [35].

A further limitation is that technical configuration and schedule optimization are mutually dependent. Hence, creating a method that simultaneously optimizes both dimensions without creating a circular relationship is challenging.

4.2. Constraints on the transferability of results

A general issue when examining existing biogas plants is that, even if they share common characteristics, most of them are highly individual in construction and operational management. The chosen plants do not represent extraordinary types of agricultural biogas plants in Germany, but both of them exhibit individual characteristics. The main obstacles to transferability, in terms of the best flexibilization strategies, are not only differences in the installed power but also the relative amount of biogas storage. First of all, this depends on the existing inventory of the CHPUs, their efficiency factor, and the way the operators construct their plants. It is interesting to note that there was a moderate increase in the capacities of Plant A while Plant B was enlarged to a much greater extent. This means that Plant A’s new CHPU can provide base load generation, and thus, the additional efficiency can be fully used. If the PQ becomes greater than 2, the new CHPU has to provide peak load generation because it needs more gas, which is constantly produced by fermentation.

Nevertheless, this paper takes a more detailed look at a small number of plants rather than a more simplified approach that covers several plants. Individual characteristics of the given plants must be evaluated before the results can be transferred.

4.3. Possible trade-offs between greenhouse gas emissions and profitability

In order to analyse possible trade-offs between GHG emissions and profitability, a comparison was made between the observed scenarios with respect to economic results and hypothetical CO2 prices. This enabled us to consider external effects of GHG emissions from an integral perspective. Consequently, we calculated the difference between the GHG emissions \[10^3 \text{kg CO}_2\text{e} \text{a}^{-1}\] of each scenario for biogas Plants A and B (Tables VI and VII) and allocated a price for CO2 to the difference. A price of 80 € \((10^3 \text{kg CO}_2)^{-1}\) was determined as the CO2 price, which was specified as the potential damage and abatement cost of CO2 in [36]. Table VI illustrates that the lower GHG emissions of Biogas Plant A may be accompanied by a better average annual gain or loss over the status quo. Plant A’s AC-SF-OPTIMIZED DAILY scenario had the lowest GHG emissions with 768.1 \(10^3 \text{kg CO}_2\text{e} \text{a}^{-1}\) and the best average annual gain (52 k€ a\(^{-1}\)). But scenario SQ-FF-OPTIMIZED DAILY, with the second lowest GHG emissions (772.7 \(10^3 \text{kg CO}_2\text{e} \text{a}^{-1}\)), achieved the worst economic result with an average annual gain or loss of −82.2 k€ a\(^{-1}\).

Like Plant A, Plant B showed no direct correlation between GHG emissions and the average annual gain or loss (Table VII). For example, scenario AC-FF-HIGH TARIFF, with the highest GHG emissions of 784.0 \(10^3 \text{kg CO}_2\text{e} \text{a}^{-1}\), was the best economic scenario for Plant B. Because there were only slight differences in GHG emissions between the scenarios of each plant, a CO2 price of 80 € \((10^3 \text{kg CO}_2)^{-1}\) did not significantly influence the economic results. For Plant A, the difference between the highest and the lowest GHG emission per year was approximately 16 \(10^3 \text{kg CO}_2\text{e} \text{a}^{-1}\) (Table VI), and for Plant B, it was about 10 \(10^3 \text{kg CO}_2\text{e} \text{a}^{-1}\). This is why the price of CO2 did not change the order of the scenarios. The average annual gain or loss went down for each scenario instead of changing the order of the scenarios based on GHG emissions. However, due to the efficiency of the CHPU and the additional amount of electricity, there is also an incentive for the owner of a biogas plant to indirectly reduce GHG emissions (Sections 3.1 and 3.2).

4.4. Policy implications of the findings

In Germany, about 8000 biogas plants with an installed capacity of 3500 MW\(_{el}\) and electricity generation of about 27.6 TWh\(_{el}\) (2014) play an important role in the electricity system. At the moment, the greatest proportion of biogas plants use base load generation [37]. Flexible power generation in biogas plants could improve the integration of variable renewable energies in a future electricity system [8]. The current incentive within the support scheme EEG – a premium payment for flexibility – promotes investment, especially in new and additional CHPUs, and/or additional gas storage capacities. However, the current price signals of the EPEX Spot SE do not stimulate flexible power generation improving the integration of variable renewable energies. The economic assessment (Figures 6 and 7) shows that additional revenues from EPEX Spot SE are insignificant. Forecasting price volatility of EPEX Spot SE over multiple years is very difficult, and operators of biogas plants and investors have to determine the price structure. Therefore, to improve the economic feasibility of flexibility options, like biogas plants and battery storage, the excess capacities of conventional power plants need to be reduced [38]. By scaling down excess capacities of inflexible fossil power plants, especially
Flexible power generation scenarios for biogas plants

M. Lauer et al.

5. CONCLUSIONS

Biogas plants, especially those with large gas storage capacities, heat sinks and no temporal limitation of the heat supply, can economically benefit from flexible power generation. Investments in flexible power generation are stimulated by two aspects: the premium payment for flexibility and an additional premium payment for direct sales due to higher electrical efficiency of the new or additionally installed CHPU. Both aspects are incentivized by the feed-in tariff system. However, additional revenues from power sales on the EPEX Spot SE are quite marginal. Expenses are predominantly investments in the CHPU and additional gas and heat storage capacities depending on the scenario.

A comparison of two different existing biogas plants reveals that most favourable scenarios for flexibilization are influenced by the power quotient and the electrical efficiency of the CHPU.

Our results show that the difference between the revenues of daily-optimized and fixed schedules is very small because of limited price volatility on the EPEX Spot SE. As a result, an energy system with a higher share of variable renewable energy sources needs sufficient price signals in order to integrate flexible power generation [40,41].

Relative GHG emissions from flexible biogas plants are significantly lower than from gas–steam power stations.

CO₂, carbon dioxide; SQ, status quo; AC, additional capacity; SF, semi-flexible; FF, fully flexible; CS, current schedule; DH, double hump; OD, optimized daily; HT, high tariff; GHG, greenhouse gas.

| Plant A | GHG emissions | CO₂ price = 0 € (10³ kg CO₂⁻¹) | Difference (CO₂ price = 80 € (10³ kg CO₂⁻¹)) |
|---------|---------------|---------------------------------|---------------------------------------------|
|         |               | Average annual gain or loss [€/a⁻¹] | Discounting payback period [a] | Average annual gain or loss [€/a⁻¹] | Discounting payback period [a] |
| SQ-SF-CS | 777.4         | 9.4                              | 7.4                                         | -1.0                           | 0.1                                         |
| SQ-SF-DH | 777.4         | 11.9                             | 7.0                                         | -1.0                           | 0.0                                         |
| SQ-SF-OD | 777.4         | 13.5                             | 6.7                                         | -1.0                           | 0.1                                         |
| SQ-FF-OD | 772.7         | -82.2                            | -2.3                                        | -0.6                           | -0.1                                        |
| AC-SF-OD | 768.1         | 52.0                             | 6.3                                         | -0.1                           | 0.0                                         |
| AC-FF-OD | 780.9         | -59.0                            | -1.3                                        | -1.3                           | -1.5                                        |
| AC-FF-HT | 784.0         | -3.0                             | -1.5                                        | -1.5                           | -1.5                                        |

From a utilities perspective, investment in the conversion of base load biogas plants to flexible plants may be economically feasible. This depends on plant-specific parameters such as gas storage capacity.

For future research, we suggest further investigations into the trade-off between the reduction of GHG emissions and the economic feasibility of biogas plants with flexible power generation. Our results show there is no direct correlation between the lowest level of GHG emissions and the best average annual gain. Therefore, interdependencies between incentive instruments (premium payment for flexibility) and market signals for flexible and economically feasible power generation of biogas plants with relatively low GHG emissions within the electricity systems should be studied.

CO₂, carbon dioxide; SQ, status quo; AC, additional capacity; SF, semi-flexible; FF, fully flexible; CS, current schedule; DH, double hump; OD, optimized daily; HT, high tariff; GHG, greenhouse gas.

| Plant B | GHG emissions | CO₂ price = 0 € (10³ kg CO₂⁻¹) | Difference (CO₂ price = 80 € (10³ kg CO₂⁻¹)) |
|---------|---------------|---------------------------------|---------------------------------------------|
|         |               | Average annual gain or loss [€/a⁻¹] | Discounting payback period [a] | Average annual gain or loss [€/a⁻¹] | Discounting payback period [a] |
| SQ-SF-CS | 305.3         | 1.6                              | 9.5                                         | -0.3                           | 0.1                                         |
| SQ-SF-DH | 305.3         | 5.0                              | 8.7                                         | -0.3                           | 0.1                                         |
| SQ-SF-OD | 305.3         | 4.6                              | 8.8                                         | -0.4                           | 0.1                                         |
| SQ-FF-OD | 311.8         | 9.8                              | 8.0                                         | -0.9                           | 0.1                                         |
| AC-SF-OD | 310.6         | 1.8                              | 9.7                                         | -0.8                           | 0.1                                         |
| AC-FF-OD | 314.1         | -2.3                             | -1.1                                        | -1.1                           | -1.1                                        |
| AC-FF-HT | 315.4         | 28.1                             | 5.8                                         | -1.2                           | 0.1                                         |

The economic feasibility of biogas plants depends on plant-specific parameters such as gas storage capacity.

Flexible power generation scenarios for biogas plants

M. Lauer et al.

5. CONCLUSIONS

Biogas plants, especially those with large gas storage capacities, heat sinks and no temporal limitation of the heat supply, can economically benefit from flexible power generation. Investments in flexible power generation are stimulated by two aspects: the premium payment for flexibility and an additional premium payment for direct sales due to higher electrical efficiency of the new or additionally installed CHPU. Both aspects are incentivized by the feed-in tariff system. However, additional revenues from power sales on the EPEX Spot SE are quite marginal. Expenses are predominantly investments in the CHPU and additional gas and heat storage capacities depending on the scenario.

A comparison of two different existing biogas plants reveals that most favourable scenarios for flexibilization are influenced by the power quotient and the electrical efficiency of the CHPU.

Our results show that the difference between the revenues of daily-optimized and fixed schedules is very small because of limited price volatility on the EPEX Spot SE. As a result, an energy system with a higher share of variable renewable energy sources needs sufficient price signals in order to integrate flexible power generation [40,41].

Relative GHG emissions from flexible biogas plants are significantly lower than from gas–steam power stations.
APPENDIX A: RESULTS OF THE ECONOMIC ASSESSMENT

Table A.1. Detailed cost and revenue data from both biogas plants in all scenarios with different plant configurations, various modes of operation and schedules compared to pre-flexibilization. Explanation: SQ: status quo; AC: additional capacity; SF: semi flexible; FF: fully flexible; CS: current schedule; DH: double hump; OD: optimized daily; HT: high tariff.

| Biogas Plant A | Revenues | Unit | SQ-FS-CS | SQ-FS-DH | SQ-FS-OD | SQ-FF-OD | AC-SF-OD | AC-FF-OD | AC-FF-HT |
|----------------|----------|------|----------|----------|----------|----------|----------|----------|----------|
| Premium payment for flexibility [€ a⁻¹] | 34.5 | 34.5 | 34.5 | 20.2 | 88.8 | 45.3 | 47.7 |
| Additional revenues from EPEX [€ a⁻¹] | 0.7 | 4.0 | 5.6 | 8.5 | 12.0 | 43.4 | 26.8 |
| Premium payment for direct sales and EPEX revenues [€ a⁻¹] | 40.5 | 40.5 | 40.5 | 41.9 | 106.5 | 110.9 | 110.7 |
| Revenues for secondary control power [€ a⁻¹] | −12.8 | −12.8 | −12.8 | −93.4 | −14.7 | −93.4 | −30.3 |

| Expenses | Unit | SQ-FS-CS | SQ-FS-DH | SQ-FS-OD | SQ-FF-OD | AC-SF-OD | AC-FF-OD | AC-FF-HT |
|----------|------|----------|----------|----------|----------|----------|----------|----------|
| Capital-related expenses [€ a⁻¹] | 32.7 | 32.7 | 32.7 | 32.7 | 98.5 | 118.3 | 112.8 |
| Operation-related expenses [€ a⁻¹] | 17.2 | 18.0 | 18.0 | 23.4 | 33.7 | 35.7 | 34.1 |
| Other expenses [€ a⁻¹] | 2.7 | 2.7 | 2.7 | 2.7 | 8.2 | 9.9 | 9.5 |
| Average annual gain or loss [€ a⁻¹] | 10.4 | 12.9 | 14.5 | −81.6 | 52.1 | −57.5 | −1.5 |
| Discounting payback period [a] | 7.3 | 7.0 | 6.6 | − | 6.3 | − | − |

| Biogas Plant B | Revenues | Unit | SQ-FS-CS | SQ-FS-DH | SQ-FS-OD | SQ-FF-OD | AC-SF-OD | AC-FF-OD | AC-FF-HT |
|----------------|----------|------|----------|----------|----------|----------|----------|----------|----------|
| Premium payment for flexibility [€ a⁻¹] | 52.0 | 52.0 | 52.0 | 52.0 | 52.0 | 52.0 | 38.8 |
| Additional revenues from EPEX [€ a⁻¹] | 1.1 | 5.4 | 7.7 | 20.0 | 8.2 | 20.3 | 10.9 |
| Premium payment for direct sales & EPEX revenues [€ a⁻¹] | 13.3 | 13.3 | 13.3 | 36.7 | 32.6 | 45.1 | 49.7 |
| Revenues for secondary control power [€ a⁻¹] | −5.9 | −5.9 | −5.9 | −20.6 | −5.9 | −20.6 | −5.3 |

| Expenses | Unit | SQ-FS-CS | SQ-FS-DH | SQ-FS-OD | SQ-FF-OD | AC-SF-OD | AC-FF-OD | AC-FF-HT |
|----------|------|----------|----------|----------|----------|----------|----------|----------|
| Capital-related expenses [€ a⁻¹] | 40.3 | 40.3 | 42.5 | 49.2 | 59.7 | 65.8 | 47.9 |
| Operation-related expenses [€ a⁻¹] | 15.3 | 16.2 | 16.5 | 25.1 | 20.5 | 27.9 | 14.2 |
| Other expenses [€ a⁻¹] | 3.3 | 3.3 | 3.5 | 3.9 | 4.9 | 5.3 | 3.9 |
| Average annual gain or loss [€ a⁻¹] | 1.6 | 5.0 | 4.6 | 9.8 | 1.8 | −2.3 | 28.1 |
| Discounting payback period [a] | 9.5 | 8.7 | 8.8 | 8.0 | 9.7 | − | 5.8 |

ACKNOWLEDGEMENTS

We acknowledge the funding (grant no. 03 KB073) from the German Federal Ministry for Economics and Technology as well as the German Federal Ministry of the Environment, Nature Conservation and Nuclear Safety.

REFERENCES

1. Abdullah MA, Agalgaonkar AP, Muttaiq KM. Climate change mitigation with integration of renewable energy resources in the electricity grid of New South Wales, Australia. Renewable Energy 2014; 66:305–313. doi:10.1016/j.renene.2013.12.014.
2. Welsch M, Deane P, Howells M, O Gallachóir B, Rogan F, Bazilian M, et al. Incorporating flexibility requirements into long-term energy system models – a case study on high levels of renewable electricity penetration in Ireland, Applied Energy. 135 2014 600–615. doi:10.1016/j.apenergy.2014.08.072.
3. Federal Ministry of Economics and Technology (BMWi), Germany’s new energy policy: Heading towards 2050 with secure, affordable and environmentally sound energy, 2012.
4. Jacobson MZ, Delucchi MA. Providing all global energy with wind, water, and solar power, part I: technologies, energy resources, quantities and areas of infrastructure, and materials. Energy Policy 2011; 39:1154–1169. doi:10.1016/j.enpol.2010.11.040.
5. Harnessing Variable Renewables: A Guide to the Balancing Challenge. International Energy Agency: Paris, 2011.
6. Huber M, Dimkova D, Hamacher T. Integration of wind and solar power in Europe: assessment of flexibility requirements. Energy 2014; 69:236–246. doi:10.1016/j.energy.2014.02.109.
Flexible power generation scenarios for biogas plants

M. Lauer et al.

7. Hahn H, Krautkremer B, Hartmann K, Wachendorf M. Review of concepts for a demand-driven biogas supply for flexible power generation. Renewable and Sustainable Energy Reviews 2014; 29:383–393. doi:10.1016/j.rser.2013.08.085.

8. Szarka N, Scholwin F, Trommler M, Fabian Jacobi H, Eichhorn M, Ortwein A, et al. A novel role for bioenergy: a flexible, demand-oriented power supply. Energy 2013; 61:18–26. doi:10.1016/j.energy.2012.12.053.

9. Hahn H, Ganagin W, Hartmann K, Wachendorf M. Cost analysis of concepts for a demand oriented biogas supply for flexible power generation. Bioresource Technology 2014; 170:211–220. doi:10.1016/j.biortech.2014.07.085.

10. Lund PD. Clean energy systems as mainstream energy options: clean energy systems, International Journal of Energy Research. 2015 n/a–n/a. doi: 10.1002/er.3283.

11. Welsch M, Howells M, Wachendorf M. Cost analysis of concepts for a demand oriented biogas supply for flexible power generation. Bioresource Technology 2014; 170:211–220. doi:10.1016/j.biortech.2014.07.085.

12. Nykamp S, Bakker V, Molderink A, Hurink JL, Smit F. Flexible power generation scenarios for biogas plants. Energy 2013; 61:18–26. doi:10.1016/j.energy.2012.12.053.

13. Federal Ministry for the Environment, Nature Conservation and Nuclear Safety (BMU), Act on granting priority to renewable energy sources (Renewable Energy Act – EEG), 2011.

14. Hochloff P, Braun M. Optimizing biogas plants with excess power unit and storage capacity in electricity and control reserve markets. Biomass and Bioenergy 2014; 65:125–135. doi:10.1016/j.biombioe.2013.12.012.

15. Hahn H, Hartmann K, Bühle L, Wachendorf M. Comparative life cycle assessment of biogas plant configurations for a demand oriented biogas supply for flexible power generation. Bioresource Technology 2015; 179:348–358. doi:10.1016/j.biortech.2014.12.007.

16. Mauky E, Jacobi HF, Liebetrau J, Nelles M. Flexible biogas production for demand-driven energy supply – feeding strategies and types of substrates. Bioresource Technology 2015; 178:262–269. doi:10.1016/j.biortech.2014.08.123.

17. Müsgens F, Ockenfels A, Peek M. Economics and design of balancing power markets in Germany. International Journal of Electrical Power & Energy Systems 2014; 55:392–401. doi:10.1016/j.ijepes.2013.09.020.

18. A. Ortner, Market compatible integration of renewable electricity generation – potential and economics of biomass/biogas-CHP units, in: Vienna, 2012. Available from: http://eeg.tuwien.ac.at/eeg.tuwien.ac.at_pages/events/AAEE-PhD-Day-2012/13_ortner.pdf (accessed February 27, 2015).

19. European Energy Exchange (EEX), EPEX SPOT SE: day-ahead auction, (2015). Available from: http://www.epexspot.com/en/market-data/dayaheadauction (accessed March 24, 2015).

20. Anwendung von Standardlastprofilen zur Belieferung nichtleistungsgemessener Kunden. BGW: Berlin, 2006.

21. Deutscher Wetterdienst (DWD), Testreferenzzahlen von Deutschland für mittlere und extreme Witterungsverhältnisse (TRY), 2014. Available from: http://www.dwd.de/TRY (accessed March 26, 2015).

22. Bianchi M, De Pascale A, Melino F, Peretto A. Performance prediction of micro-CHP systems using simple virtual operating cycles. Applied Thermal Engineering 2014; 71:771–779. doi:10.1016/j.applthermaleng.2013.11.026.

23. Röhrich M. Fundamentals of Investment Appraisal. An Illustration Based on a Case Study. Oldenbourg Wissenschaftsverlag: München, 2007.

24. Perman R, Ma Y, Common M, Maddison D, McGilvray J. Natural Resource and Environmental Economics (4th). Pearson Education Limited: Harlow, Essex; New York, 2011.

25. Gawel E, Purkus A. Promoting the market and system integration of renewable energies through premium schemes – a case study of the German market premium. Energy Policy 2013; 61:599–609. doi:10.1016/j.enpol.2013.06.117.

26. Hennig C, Gawor M. Bioenergy production and use: comparative analysis of the economic and environmental effects. Energy Conversion and Management 2012; 63:130–137. doi:10.1016/j.enconman.2012.03.031.

27. Deutsches Institut für Normung e.V. (DIN), Umweltmanagement-Ökobilanz-Grundsätze und Rahmenbedingungen (ISO 14040:2006); deutsche und englische Fassung EN ISO 14040:2006, 2006.

28. Deutsches Institut für Normung e.V. (DIN), Umweltmanagement-Ökobilanz-Anforderungen und Anleitungen (ISO 14044:2006), deutsche und englische Fassung EN ISO 14044:2006, 2006.

29. ecoinvent Centre–Swiss Centre for Life Cycle Inventories, Ecoinvent Database 2.2, 2015. Available from: http://www.ecoinvent.ch/ (accessed March 15, 2015).

30. Bachmaier J. Treibhausgasemissionen und fossiler Energieverbrauch landwirtschaftlicher Biogasanlagen - Eine Bewertung auf Basis von Messdaten mit Evaluierung der Ergebnisunsicherheit mittels Monte-Carlo-Simulation, 2012.

31. Vogt R. Basisdaten zu THG-Bilanzen für Biogas-Prozessketten und Erstellung neuer THG-Bilanzen.
32. Pehnt M, Schneider J. Kraft-Wärme-Kopplung. In Energieeffizienz Ein Lehr- Handb. Springer Verlag: Berlin Heidelberg, 2010.
33. Kuratorium für Technik und Bauwesen in der Landwirtschaft (KTBL), Wirtschaftlichkeitsrechner Biogas, 2014. http://daten.ktbl.de/biogas/showSubstrate.do?zustandReq=3#anwendung (accessed October 1, 2014).
34. Thran D, Pfeiffer D, Adler P, Borowski A, Erik F, Herrmann A, et al. Methodenhandbuch Stoffstromorientierte Bilanzierung der Klimagaseffekte, D. Thran, D. Pfeiffer (Ed.), Leipzig DBFZ, 2013.
35. Suhl L, Mellouli T. Optimierungssysteme - Modelle. Verfahren, Software, Anwendungen, Springer Gabler: Berlin, 2013.
36. Schwemmer S, Preiss P, Müller W. Best-Practice-Kostensätze für Luftschadstoffe, Verkehr, Strom- und Wärmeerzeugung - Anhang B der "Methodenkonvention 2.0 zur Schätzung von Umweltkosten", Umweltbundesamt: Dessau-Rosslau, 2012.
37. Scheftelowitz M, Rensberg N, Denysenko V, Daniel-Gromke J, Stinner W, Hillebrand K, et al. Stromerzeugung aus Biomasse (Vorhaben IIa) Zwischenbericht Mai 2015, 2015.
38. Grashof K, Hauser E, Guss H. Aktionsprogramm flexible Kraftwerke - Die nächsten Schritte zum Erhalt der Versorgungssicherheit, IZES Saarbrücken, 2013.
39. de Menezes LM, Houllier MA. Germany’s nuclear power plant closures and the integration of electricity markets in Europe. Energy Policy 2015; 85:357–368. doi:10.1016/j.enpol.2015.05.023.
40. Henriot A, Glachant J-M. Melting-pots and salad bowls: the current debate on electricity market design for integration of intermittent RES. Utilities Policy 2013; 27:57–64. doi:10.1016/j.jup.2013.09.001.
41. Sopinka A, Pitt L. Variable energy resources: new electricity markets by design or desperation? The Electricity Journal 2013; 26:89–95. doi:10.1016/j.tej.2013.10.002.
42. Barchmann T. Flexibilisierungsansätze von Biogasanlagen - Nutzungskonzepte von Blockheizkraftwerken für eine bedarfsorientierte Stromerzeugung, Master Thesis, University of Leipzig, 2013.
43. German Federal Ministry for Economic Affairs and Energy, The Renewable Energy Sources Act (EEG), 2014.
44. Internet platform for control reserve tendering of the German transmission system operators, Tender overview, 2015. https://www.regelleistung.net/ip/action/ausschreibung/public?language=en (accessed March 24, 2015).