LANDTECHNIK 75(2), 2020, 81–102
DOI:10.15150/lt.2020.3235

Further operation of flexible biogas plants – realisable bid prices in the EEG 2017

Kevin Haensel, Tino Barchmann, Martin Dotzauer, Erik Fischer, Jan Liebetrau

With the tendering procedure of the Renewable Energy Sources Act (Erneuerbare-Energien-Gesetz, EEG) 2017, the opportunity was created to transfer existing biogas plants into a 10-year follow-up remuneration through new commissioning. A detailed analysis of possible revenues and costs can be an advantage when placing bids. Thus provide clarity about the economic situation of a biogas plant during the follow-up period. The aim of this paper is to demonstrate that there are potential economic options for selected existing biogas plants in Germany in the electricity market. Namely to switch to the tender design under EEG 2017 and to take advantage of the 10-year follow-up remuneration. For now, the tender corridors beyond 2022 are not determined yet. But in the course of an upcoming amendment of the Renewable Energy Sources Act it is likely that there will be a notable corridor volume from 2023 onwards. In addition to the ability to operate flexibly, the decisive factor for the economic operation of a plant beyond the 20-year EEG remuneration period is the levelized costs of electricity (LCOE). Or more precisely the LCOE that can be realized in the follow-up period. If a subsidy charge can be achieved that, combined with market earnings, exceeds the average LCOE in the follow-up period, economic operation is ensured. Otherwise, additional sources of revenue or cost reduction potential must be tapped.

Keywords
Biogas, flexibilisation, economic efficiency, EEG 2017, tender procedure, bid prices

In the context of the energy transition, electricity feed-in from volatile regenerative energy sources has increased significantly in Germany since the millennium. As a result, the residual load in the electricity system is subject to rising fluctuations at short intervals, resulting in a growing need for flexible provision capacities to compensate for the residual load fluctuations. The EEG has been encouraging the demand-based provision of electricity from biogas via direct marketing and the flexibility bonus since 2012. Direct marketing already being mandatory for certain new plants since the EEG 2012. The EEG 2017 tendering procedure created the possibility of transferring existing plants into a 10-year follow-up remuneration. Through new commissioning in accordance with § 39f EEG 2017 plants could extend their operation. In order to be able to participate in the tender and thus ensure the economic continuation of operation after the expiration of the 20-year EEG remuneration period, yearly power generation is limited to 50 % of the installed capacity. So biogas plant operators must maintain at least twice the output of a combined heat and power unit (CHP) in relation to the rated output. In the case of existing biogas plants, the investment in flexibilisation should be financed by the payment of the flexibility bonus. The flexibility bonus is paid for up to 10 years over the remaining term of the first EEG remuneration period for additional installed electrical capacity or decreasing the rated power. The complete discontinuation of the previous EEG remuneration after 20 years can be

received 17 April 2019 | accepted 3 April 2020| published 29 May 2020

partially compensated for the subsequent 10-year follow-up funding. In addition, a successful switch into the tender design entitles the operator to a flexibility surcharge of 40 euros per kilowatt and year for installed electrical CHP capacity in accordance with § 50a EEG 2017. Whether the continued operation of existing biogas plants via this follow-up remuneration represents an economically viable concept, must be determined individually for each biogas plant. In addition to the legally stipulated support via the flexibility bonus and flexibility surcharge, the minimum bid price that the plant can achieve while covering the annual costs incurred in the follow-up period plays a decisive role. Thus, a reasonable bid price range can be identified, which is determined by the system-specific cost-covering minimum bid price and the maximum bid price of the tender. This offers biogas plant operators the opportunity to estimate the extent of possible profits in the EEG follow-up tariff and to exploit the continued economic operation of their biogas plant by submitting a well-founded bid.

In the third tender for biomass plants under the EEG 2017 as on April 1st 2019, the available tender volume of 133.3 megawatts (MW) in total was again not exhausted. Among the 19 subsidised biomass plants with a total installed capacity of 25.5 MW were 15 existing plants (> 150 kW installed electrical capacity) with a total installed capacity of around 22.5 MW. They were able to bid at a maximum bid price of 16.56 EUR ct kWh_{el}^{-1} (2020: 16.40 EUR ct kWh_{el}^{-1}), set in accordance with section § 39f (5) no. 3 EEG 2017, with the weighted average bid value being 12.12 EUR ct kWh_{el}^{-1} (BNetzA 2019a). After the first three tenders under EEG 2017, a total of 83 existing biomass plants (> 150 kW of installed electrical capacity) with a total installed capacity of around 89.3 MW have already been awarded a contract to switch to the tendering regime under the EEG 2017.

Making a biogas plant more flexible by increasing the installed electrical capacity to at least twice the rated capacity or reducing the rated capacity to half of the already installed electric capacity are fundamental prerequisites in line with § 39h (2) EEG 2017 for receiving payments after a successful tender. However, in addition it is necessary to more precisely specify how the plant should ideally be configured in order to be able to serve the most attractive segments of the electricity market after flexibilisation. Of the seven indicators for flexible biogas plants described in (Dotzauer et al. 2019), not only the power quotient (ratio of installed capacity and rated capacity) is relevant here, but also the reaction speeds in the form of load ramps, as well as the time periods at high and low load, which are largely determined by the mode of operation and the available gas storage (Lauer et al. 2017). These show that flexible operation is the most lucrative under the current framework conditions, in which all CHPs of a biogas plant form a virtual power block which is operated in start-stop mode. Existing plants can transit into the tendering regime under EEG 2017 in case of a successful bid participation. After the public announcement of the acceptance of the bid a time range for the actual transition opens, starting from 12 months until 36 months after the announcement in accordance with § 39f (2) EEG 2017. After the latest amendment of § 28 (3) EEG 2017, the tenders take place twice a year on 1 April as well as 1 November. This means that if participation takes place more than 36 months before the end of the first EEG remuneration period, even if successful, the plant would lose its entitlement to subsidies for part of the first remuneration period. In case of participation in a tender with less than 12 months before the end of the first remuneration period, the plant would neither be able to claim the existing nor the auctioned payments from the tender for a certain amount of time and therefore temporarily only was able to generate the revenues from the European Power Exchange (EPEX Spot). In order to ensure a seamless transition, participation in a tender should therefore take place in compliance with the above-mentioned transitioning deadlines.

As a result of the act to amend the Renewable Energy Sources Act (Energiesammelgesetz) of 17 December 2018, the total amount of additionally installed electrical capacity remunerated via the flexibility bonus that is installed after 31 July 2014 and reported to the register for market master data (Marktstammdatenregister) of the Federal Network Agency (Bundesnetzagentur, BNetzA) will be reduced from 1,350 MW to 1,000 MW. This cap was reached at the end of July 2019, which means that a 15-month transition period until 30 November 2020 has now come into force, during which the first-time use of the flexibility bonus beyond the cap is still possible (BNetzA 2019b). Once this transitional period has expired, existing biomass plants will no longer be entitled to gain the flexibility bonus under the EEG 2017.

The ten-year extension within the tender design results in several additional costs for the operators of existing biogas plants. In particular, these can be investments in additional technical components within the framework of flexibilisation and their integration, technical and structural maintenance and repowering measures on the existing plant as well as new (approval) legal ordinances, regulations and laws. In order to ensure that these additional costs can be compensated, additional sources of revenue should always be considered in the follow-up period.

In particular, the optimised use of heat from on-site electricity generation plants is catching attention. Today, there are numerous examples in practice on how this can be implemented, not only to optimise heat utilisation but to increase revenues as well. These can be aspects of the seasonal shift in heat supply and consumption via large heat storage facilities, including possible seasonal feeding of substrates, the expansion or new development of additional heat sinks, the provision of higher-value process heat and the expansion of heat supply quality in the form of full supply including peak load coverage (Welteke-Fabricius 2018). However, there are considerable differences in Germany regarding the willingness to pay for the purchase of heat for heating and hot water supply. For household customers with a basic supply contract for natural gas, these were on average 6.99 EUR ct kWh^{-1} (thermal) in 2016 and 6.64 EUR ct kWh^{-1} (thermal) in 2018 (Statista 2019). The average willingness to pay for the purchase of heat from a biogas plant in the same year was only 2.2 EUR ct kWh^{-1} (thermal) without a guaranteed full supply and 3.90 EUR ct kWh^{-1} (thermal) with a corresponding full supply (Fachverband Biogas e. V., 2016). As a possible explanation, Strobl (2017) mentions cross-subsidisation through the CHP bonus of the EEG 2004 and EEG 2009, an unfavourable choice of location for the biogas plant, which makes it more difficult to develop a valuable local heating market, as well as insufficient marketing on the part of the biogas plant operators to attract customers with a higher willingness to pay for heat.

Due to the focus of this paper on the economic efficiency of plants in the electricity market, no separate investigation of heat optimisation and its individual challenges will be made at this point. Instead, reference is made to further specialised literature, e.g. (Herbes et al. 2018, Karschin and Geldermann 2015, Dotzauer et al. 2016). From a technical point of view, there are various options for flexibilisation in the electricity sector, e.g. through pumped storage, battery power plants, supercaps (Sterner and Stadler 2017) or through demand-side management. There is no in-depth explanation of flexibility options in the electricity sector provided here, due to the legal framework conditions under EEG 2017 for the flexibilisation of biogas plants via the flexibility bonus and surcharge.

Materials and methods

The methodology used in order to determine the feasible bid prices, which need to at least cover the LCOE of a biogas plant during the follow-up period, will be described in this section: first the calculation tools, then the methodological principles, afterwards the selected practical plants and at last the derivation of the flex scenarios.

Description of the tool box “BioFlex”

The basic procedure for the economic analysis of biogas plants has been implemented in an update of the “BioFlex” tool box. “BioFlex” has been developed at the German Biomass Research Centre (Deutsches Biomasseforschungszentrum, DBFZ) for several years and allows economic efficiency calculations based on the annuity method according to the guideline of VDI 2067 “Economic efficiency of building services installations - principles and cost calculation” (VDI 2000). The tool box consists of a total of six calculation modules, which are created as individual Microsoft® Excel® files and exchange data with each other via Visual Basic for Applications (VBA) scripts. Furthermore, some modules also contain VBA scripts to perform automated internal calculations and display results graphically. The basic functional diagram of the “BioFlex” tool box in its previous version, which has already been used for a study by the Agency for Renewable Energy (Agentur für Erneuerbare Energien, AEE) (Dotzauer et al. 2018), is shown in Figure 1. For the present study, the economics module has been adapted in such a way that the different observation periods (EEG 1.0, EEG 1.1, EEG 2.0), which are explained in Chapter 2.2, can not only be considered and evaluated individually but also together, which was not possible before.

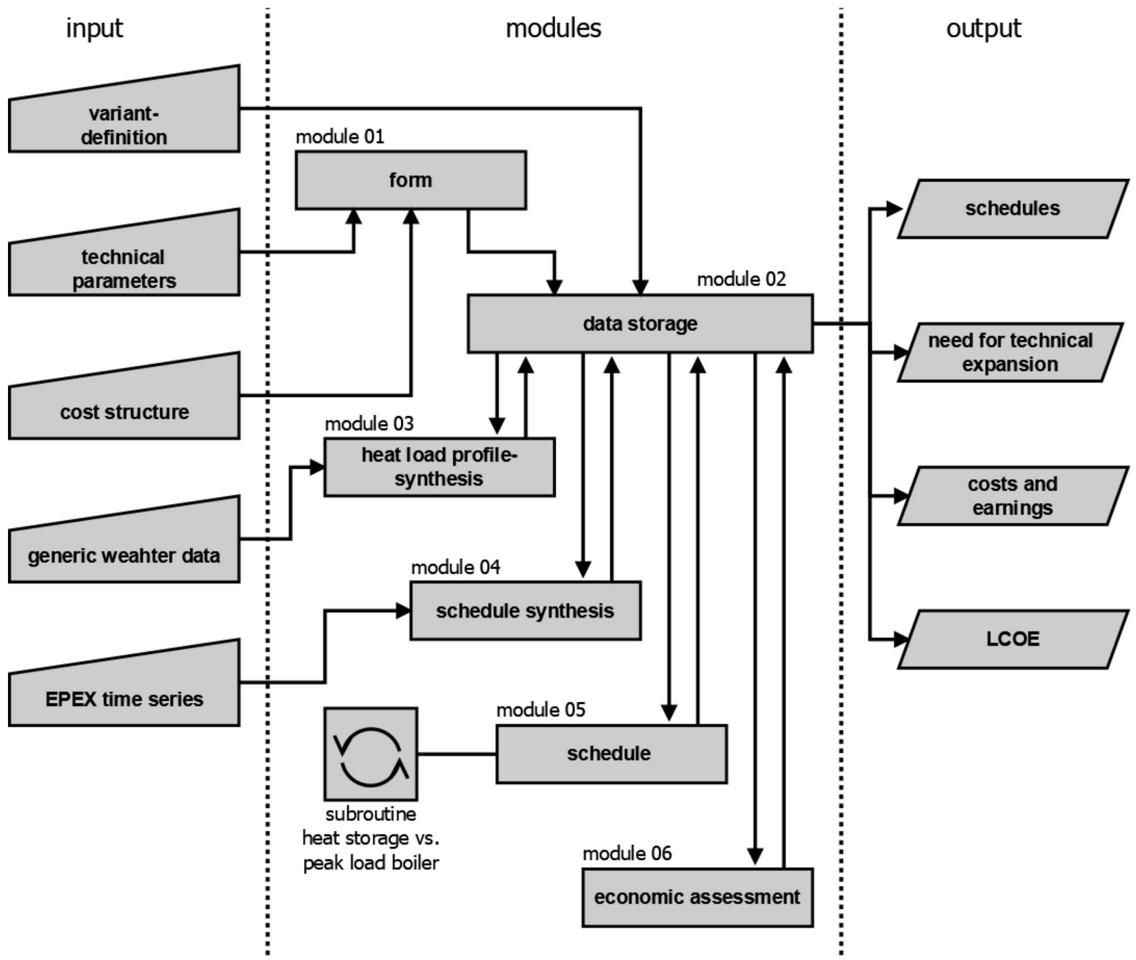


Figure 1: Functional diagram of the “BioFlex” tool box, divided into input, modules and output

First, relevant technical and economic parameters of the biogas plant are entered into the data storage (module 02) using a form (module 01). Furthermore, heat load profiles are created based on real-time weather data from the German Weather Service from the reference year 2017 (module 03). The generation of the CHP schedules in Module 04 is performed by optimizing the hourly prices of the EPEX Spot on a daily basis using a price ranking methodology based on price data from 2017 (EPEX Spot) (EPEX Spot SE 2018). Apart from the available electrical capacity of the installed CHP plants, no further technical restrictions are assumed. In order to ensure a gentle flexible CHP operation, the direct marketer usually considers restrictions. Foremost the daily start-stop operations are limited to a maximum of two to three daily starts or stops, minimum running times after a start, as well as minimum downtimes after a stop when creating flexible schedules in practice. A simplification of the flexible mode of operation is provided by so-called double humps, whereby in the morning and early evening hours, hours with on average higher electricity prices on the power exchange are run in a continuous block. The lengths of the power generation blocks depend on the additional electrical power. Furthermore, it can be stated that especially on working days and in the winter months, high electricity prices prevail and a corresponding concentration of CHP plant operation in these periods can lead to additional revenues compared to a continuous operation (Strobl 2018).

Basics of the economic analysis

The economic analysis comprises five operational biogas plants, each with three scenarios in terms of different power quotients (Q_P) of the CHP at constant rated capacity. The three scenarios are roughly based on power ratios of $Q_P \approx 2$ (flex-scenario A), $Q_P \approx 3$ (flex-scenario B) and $Q_P \approx 4$ (flex-scenario C) of the installed electrical CHP power.

In the following, the adaptation of the methodology for the economic efficiency calculation in module 06 "economy" of the "BioFlex" tool box is described in detail. The economic analysis includes a dynamic investment calculation in the form of the annuity method, which is based on VDI 2067. This method was adapted to the time sequence of investment measures typical for the flexibilisation of an existing biogas plant. This means that the biogas plants considered in this contribution have each reached about half of their 20-year remuneration period or are already in the second half of their EEG remuneration phase and are investing in technical extension for flexibilisation at this point in time. As shown in Figure 2, these investment measures are divided into three chronologically staggered sub-sections: EEG 1.0, EEG 1.1 and EEG 2.0. As a result of the economic analysis, the annuities for revenues and costs of the biogas plants over the respective periods are given and based on this, the LCOE for a 10-year period after the end of the first remuneration period are given in cents per kilowatt hour. The total annuities of the three subsections can be interpreted as average annual profit or loss.

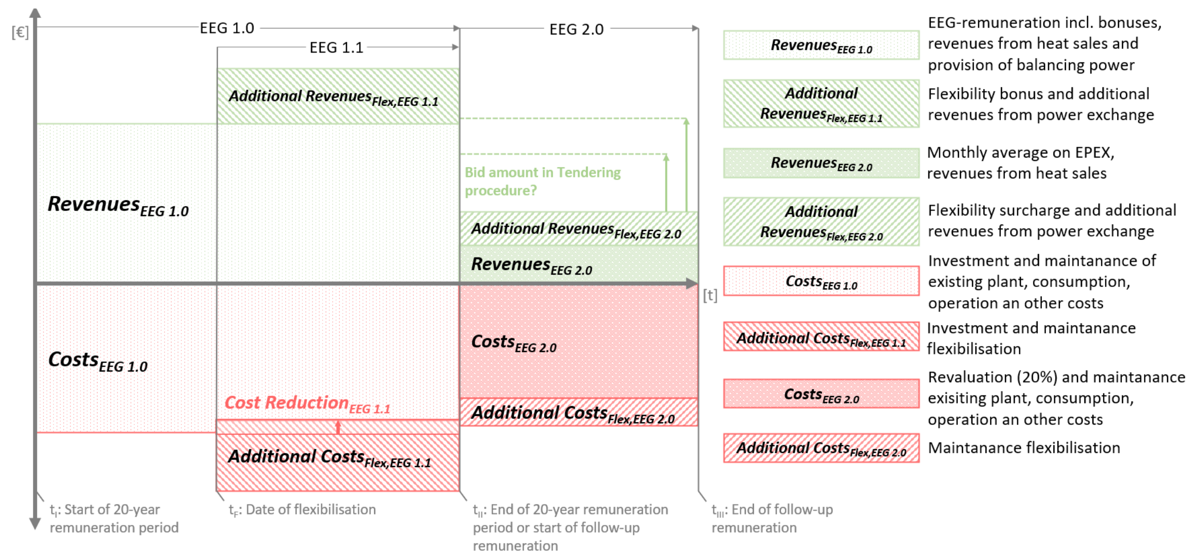


Figure 2: Scheme of the economic analysis depending on the sections of the investment project

Section EEG 1.0 reflects the status quo of the plant without investment in flexibilisation, where the plant is operated in its current form only until the end of the 20-year EEG remuneration period. In the context of this paper, it is assumed that the decommissioning of the biogas plant does not result in costs due to the dismantling or revenues due to a residual value. Even if in practice provisions for the dismantling of a biogas plant should normally be made in accordance with the legal requirements for approval. Provisions amounting to about 5 % of the investment in the new plant or the initial investment can be calculated here (Hoffstede et al. 2018). For the cogeneration units, a general overhaul is considered after 65,000 operating hours and a replacement investment after further 30,000 operating hours (total lifetime expectancy of 95,000 hours). The basic annuity of the biogas plant is determined over the entire EEG remuneration period of 20 years. In order to apply the annuity method, it is necessary at this point to transform all historically accrued subsequent investments to their present value in the period t = 0 using the discount factor.

The annual consumption, operation and other costs of the year 2017 were requested from the biogas plant operators. Since the annuity method takes a constant price increase into account, starting from the beginning of the observation period, the adjusted methodology initially calculates the annual costs back to the price level of the first year of operation of the plant before calculating the price-dynamic annuity with the underlying price change rate. The annuity is then calculated over the entire 20-year EEG remuneration period using the price-dynamic annuity factor.

Section EEG 1.1 maps the period from the investment in flexibilisation to the end of the 20-year EEG remuneration period. In addition to the basic annuity of the existing plant, additional costs and additional revenues are incurred due to the flexibilisation. The investment in flexibilisation is fully distributed over the remaining term of the 20-year EEG remuneration and thus increases the LCOE in section EEG 1.1. There is therefore no residual value for the investment in flexibilisation at the end of the 20-year EEG remuneration period.

The EEG 2.0 section looks at the 10-year EEG follow-up remuneration, depending on a successful participation in the tendering procedure under EEG 2017, assuming that the transition to the follow-up remuneration will take place exactly when the 20-year EEG remuneration expires. In addition, a simplified and flat-rate revaluation of the biogas plant is carried out. In the economic calculations of Daniel-Gromke et al. (2020) a fixed period from 2020 to 2030 was specified for the EEG 2.0 section and the reinvestment factors were drawn up on due to structural and technical components. On that basis, an average reinvestment factor of 20 % of the initial investment volume is used in this paper, which is intended to cover the costs of comprehensive plant renovations for the planned extension of the plant's operation. The CHP units are not part of the revaluation, since costs for overhauls and replacement investments are calculated within the operation lifetime of the CHPs as described above. In addition to the revaluation, the current costs and revenues of the existing plant and of the flexibilisation are considered.

Figure 2 shows a schematic overview of the adapted methodology of the economic analysis depending on the three time sections of the investment project. The cost reduction in the EEG 1.1 section results from the reduced running times of the flexible CHPs compared to the reference scenario and the associated lower maintenance and repair costs. In the EEG 2.0 section the biogas plant generates market revenues, which consist of the average electricity revenues on the EPEX power exchange (monthly average), the additional revenues achievable on the power exchange through electricity price-oriented operation, and possible heat sales to external customers. To cover the total costs determined, the flexibility surcharge and the market premium, which corresponds to the bid price in the event of successful participation in the tender, minus the monthly average on EPEX, are granted.

With the introduction of the mixed price procedure, the legal framework for the provision of balancing power in 2018 was changed by the BNetzA. These are currently being critically questioned by many market participants (BEE 2019). As a result of these changes and further foreseeable adjustments to the legal framework, the revenues to be generated in future from the provision of balancing power by biogas plants are subject to a high degree of uncertainty from today's perspective. Therefore, these revenues from the provision of balancing power are not included in section EEG 2.0. Due to the complete abolition of the former bonus system and the annual degression rate of the maximum bid price limit of 1 % in the tender design under EEG 2017, cost recovery for biogas plants will become much more ambitious in the future and will depend strongly on the level of the LCOE of the individual plants.

Taking into account the revenues and costs incurred by the plant flexibilisation, the extension of the period under consideration by ten years as well as the inclusion of the later valid funding conditions, the LCOE of the biogas plant can be determined for the follow-up period. First, it can be calculated whether the LCOE of the plant in the follow-up period, after deduction of the additional revenues described above, are below the maximum bid price limit and whether the respective plant is therefore eligible at all for participation in a tender under the condition of a continued economic operation in the follow-up period. In a further step, it is also possible to estimate how the overall profitability of the biogas plant will develop in the follow-up period depending on the remuneration within the EEG 2.0. On the one hand, the achievable revenues in EEG 2.0 can be described by the possible maximum bids. However, it is also possible to determine the payment tariffs in EEG 2.0 with which the LCOE of the biogas plant are covered exactly. This therefore represents the minimum bid price with which the chances of an award of contract can be increased in the case of oversubscribed tenders and under which the plant can be safely transitioned to the follow-up remuneration. Even if that means, that the potential for additional profits is left behind, since the award of contract is carried out according to the pay-as-bid procedure and operators of biogas plants only receive the payments as offered as bids when the contract is awarded.

The expansion of existing heat utilisation concepts is not taken into account in the calculation, but could have further positive influence on the economic efficiency in the EEG 2.0 section and should be considered in practice.

Selection and description of the investigated biogas plants

For this contribution, a total of five agricultural biogas plants in Germany were selected, which are located in the three federal states of Brandenburg, Saxony or Thuringia. All plants were monitored within the framework of the research project „Biogas-Messprogramm III – Teil 1: Faktoren für einen effizienten Betrieb von Biogasanlagen; Teilvorhaben 1: Energiebilanzierung, Flexibilisierung, Ökonomie“ (Funding reference number: 22403515, Project Management Agency: Agency for Renewable Resources [Fachagentur für Nachwachsende Rohstoffe e. V., FNR]). A one-year plant monitoring was carried out, including the recording of energy flows from the biogas plant, regular analysis of biological process parameters and the acquisition of economic data. The plant monitoring was divided into two periods (2016/2017 and 2017/2018), in which a total of 30 biogas plants were examined.

The following criteria played an important role in the particular selection from the total of 60 biogas plants examined:

- Existing data quality regarding economic indicators,
- The age of the biogas plant and
- The differentiation of the plants with regard to installed electrical output, substrate use, heat concept and considerations of the particular plant operator regarding flexibilisation including an extension of operation through participating in the tendering procedure under the EEG 2017

In particular, the focus should be on plants, which currently have no or very little flexibility (BGP 04) and have reached about half of their 20-year remuneration period. As the flexibility bonus is granted for a maximum of 10 years, this timeframe should be used most effectively for the refinancing of the flexibility-related investments in section EEG 1.1 and to therefore provide an economic relief for section EEG 2.0. If the remaining life of a plant is significantly shorter, this would have a negative impact on the overall economic result in section EEG 1.1, since an ineffective utilisation of the flexibility bonus makes it more difficult to refinance the flexibility investments and can therefore also burden the following period (EEG 2.0) in terms of costs.

To take care of gas storage drift caused by changing gas conditions, mostly temperature oscillations, 80 % of the available gross gas storage volume is used for the conversion from gross volume to usable net volume for all five existing biogas plants. Temperature fluctuations cause changes in volume of the gas trapped in the gas storage (non-adiabatic or quasi isobaric changes of state), which reduce the net storage volume. For this purpose, it is assumed that at an annual mean temperature within the gas storage tank of 40 °C, a maximum daily temperature fluctuation of 30 Kelvin can occur (e.g. from 25 to 55 °C). Approximately 20.7 % is required for this temperature-induced expansion of the biogas (Lauer et al. 2017).

In the following, the five biogas plants (BGP) are briefly described in more detail with regard to their construction, technical design, substrate input and gas utilisation:

BGP 01 is located on the premises of a cattle and pig fattening farm in Brandenburg. The plant consists of a fermenter with a usable volume of about 1,500 m^3, designed as a circular reinforced concrete tank with an internal submersible agitator, a double membrane gas storage roof and an overflow into the secondary fermenter. The secondary fermenter with a usable volume of approximately 2,080 m^3 is also built as a circular reinforced concrete tank with a double membrane gas storage roof and two submersible agitators. Digestates are pumped into the open digestion tank, which has a storage volume of 2,650 m^3. The total gross gas storage volume at the plant is 1,450 m^3.

Since commissioning, no major refitting has been carried out on the plant. As solids, maize silage, pig manure and on site ground rye meal are fed directly into the fermenter via a 32 m^3 feeder. The fed manure consists of approximately 90 % pig manure and 10 % cattle manure. The biogas is converted in a CHP and the generated heat is used to heat the pig fattening stables and the social building at the site.

BGP 02 is located on the premises of an agricultural enterprise in Thuringia. The plant consists of a fermenter with a usable volume of 2,001 m^3, designed as a circular steel tank with central agitator, as well as a circular reinforced concrete tank as secondary fermenter with a usable volume of approximately 1,300 m^3 and an integrated foil gas storage tank with a gross gas storage volume of 600 m^3. Two submersible mixers are used in the secondary fermenter to homogenize the fermentation substrate. The digestives are stored in two circular reinforced concrete tanks with odour-reducing cover, each with a storage volume of 3,500 m^3. The plant was planned for the use of renewable raw materials (maize and grass silage) as well as for animal excrements (cow dung). The plant is categorised as a dry fermentation plant, i.e. the average dry matter content in the fermenter is between 12 and 14 %. The solids are premixed by a mobile feed mixer and dosed by a moving floor feeding system. The substrates are fed into the fermenter by a progressive cavity pump using recirculated material from the secondary fermenter. Furthermore, an additional shredder with a separator for heavy material is integrated in the feeding system. The fermenter is operated in the mesophilic process temperature range (40–45 °C). The substrate reaches the secondary fermenter and subsequently the digestion tank via overflows. The biogas is converted into electricity on site in a CHP. In addition to covering the company's own requirements, the heat generated is transferred as useful heat (process steam) to a neighbouring commercial enterprise.

BGP 03 is located on the site of a cattle fattening plant in Saxony and consists of two fermenters operated in parallel, each with a usable volume of approximately 1,300 m^3. The fermenters are designed identically as circular reinforced concrete tanks with foil gas storage and are each equipped with two long-shaft agitators. The secondary fermenter is also a circular reinforced concrete tank with a usable volume of approximately 1,500 m^3. It contains a long-shaft agitator and is used as an intermediate storage for digestives in addition to an open digestion tank. The liquid substrate cattle manure is pumped directly from the barn into the fermenters. The solid substrates maize silage and grass silage are fed by a wheel loader into the dosing tank with mixing function and from there they are fed alternately directly into the two fermenters. The operation takes place in the mesophilic temperature range (40–43 °C). A central pump is used to pump the fermentation substrate to the secondary fermenter and from there to the digestion storage. The biogas is utilised via a CHP. The useful heat is supplied to the administration building, the workshop and the milking and calving area as required.

BGP 04 is located on the premises of an agricultural enterprise in Thuringia. The plant consists of a fermenter with a usable volume of approximately 1,600 m^3 and a secondary fermenter with an usable volume for digestion storage of 5,100 m^3. Both tanks are built as circular reinforced concrete tanks with submersible agitators as well as foil gas tanks. A long-shaft agitator is also integrated in the fermenter. A manure tank with a gas-tight cover is located upstream. The solid substrates are fed directly into the fermenter via a stationary dosing mixer using a screw conveyor system. A central pump transports the liquid manure to the fermenter and the fermentation substrate to the secondary fermenter. In addition, a shredder with contaminant separation is integrated in the pumping section. The fermentation is operated mesophilic at 42–44 °C. Biogas utilisation takes place on site in two CHPs.

BGP 05 is located on the site of a cattle fattening facility in Saxony. The plant consists of a mixing tank made of reinforced concrete with a useful volume of approximately 240 m^3 and submersible agitators. There are two fermenters operated in parallel, each with a usable volume of approximately 1,400 m^3 and a secondary circular reinforced concrete fermenter with a storage volume of approximately 3,400 m^3 with submersible motor agitators. The liquid substrate cattle manure is pumped directly from the barn into the mixing tank. In accordance with the plant concept, the emission-tight mixing tank acts as a hydrolysis stage. It is connected to the gas and substrate systems of both fermenters by compensating lines. The solid materials cow dung, maize silage and grass silage are fed into the mixing container by a receiving storage and screw conveyor system. In addition to the compensating lines, a central pump transports the fermentation mixture alternately to the fermenters and to the secondary fermenter. Furthermore, there is an overflow from the secondary fermenter into the digestion storage. Foil gas tanks are located on both fermenters and on the secondary fermenter. The gas is utilized by two CHPs. The relevant characteristic data for the five examined biogas plants are summarised below in Table 1.

Table 1: Characteristics of the five biogas plants

Biogas plants	Unit	BGP 01	BGP 02	BGP 03	BGP 04	BGP 05
Installed electrical power $P_{el,plant}$	kW	265	537	540	540	562
Thereof installed electrical power CHP 1 $P_{el,CHP\ 1}$	kW	265	537	170	190	370
Thereof installed electrical power CHP 2 $P_{el,CHP\ 2}$	kW	-	-	370	350	192
Maximum rated power electrical P_{Bem}	kW	252	510	513	420	534
Power quotient Q_P*		1.05	1.05	1.05	1.29	1.05
Existing gross gas storage volume V_G	m^3	1,450	600	630	700	970
Commissioning BGP		22.12.2011	01.12.2006	01.08.2007	18.12.2009	21.06.2007
Start of flexibility bonus		-	-	-	since July 2017	approx. from mid 2019
Actual flexibile operation		no	no	no	no	no
Electricity output fed into the grid 2017	kWh	2,031,529	4,269,951	4,071,712	3,644,635	4,476,479
Substrate use 2017	Mg FM a^{-1}	6,973	9,024	23,946	29,218	18,557
Thereof cattle or pig manure	%	59	9	67	76	62
Thereof maize silage	%	38	76	25	14	31
Thereof grass silage	%	-	14	8	6	6
Thereof other input materials	%	3	1	-	2	2

* The static power quotient is calculated as the quotient of the power installed at the biogas plant $P_{el,}$ plant in kilowatts and the maximum rated power P_{Bem} in kilowatts

Derivation and description of Flex Scenarios

In the following the data on investment requirements for flexibilisation depending on the performance quotient (Q_P) of the three scenarios are presented (Table 2).

Table 2: Expansion and investments of the examined biogas plants in Flex-Scenario A (target value: $Q_P \approx 2$)

Biogas plants	Unit	BGP 01	BGP 02	BGP 03	BGP 04	BGP 05
Additional installed electrical power Flex CHP 1 $P_{el, Flex CHP 1}$	kW	300	600	600	355	800 (600)*
Power quotient after conversion Q_P		2.24	2.23	2.22	2.13	2.18
Expansion of gross gas storage volume V_G	m^3	1,250	4,500	4,175	2,600	6,000
Expansion of heat storage volume V_W	m^3	150	100	100	150	50
Investment Flex-CHP 1	EUR	271,783	442,432	442,432	305,926	525,000
Investment in new gas storage facility	EUR	45,196	79,129	76,364	61,448	151,028
Investment in additional heat storage tank	EUR	105,000	76,821	76,821	105,000	54,314
Other investments	EUR	195,000	195,000	195,000	195,000	401,000
Investments Total	EUR	616,979	793,382	790,617	667,375	1,131,342

* For BGP 05, the operator has already purchased a Flex CHP with an installed electrical output of 800 kilowatts and operates it in throttled mode at 600 kilowatts (electrical).

Scenario A (Table 2) aims at doubling the electricity generation capacity. For this purpose, the acquisition of an additional CHP unit is considered for all of the five biogas plants. The size of the CHP unit depends on the product range of the manufacturer from whom the existing units of the respective biogas plants already came from. Where price data on CHPs were available in the form of non-binding price information from the manufacturers, these were taken as the costs. Otherwise, a cost function was used from an internal data collection at DBFZ from 2013 that included a CHP manufacturer survey). The cost function is based on price data for 38 biogas CHP units from a total of ten manufacturers. A flat-rate price increase of 10 % was applied to bring the prices into line with today's price levels. The modified cost function for CHP is shown in equation 1:

$$C_{\mathrm{CHP}} = 4{,}481.4 * \mathrm{P_{el}}^{-0.297} * 1.1 \quad \text{(Eq. 1)}$$

C_{CHP} specific costs CHP in EUR kW^{-1}

P_{el} installed electrical power in kW

The additional gas and heat storage capacities are generated in the "BioFlex" tool box following the schedule generation and intersection in modules 04 and 05. Taken into account are the capacities already installed at the biogas plant on the one hand, and on the other hand, the capacities to be provided for the scenarios. Analogous to the flexible CHPs, price information from gas or heat storage manufacturers was used for the economic calculation if possible. If no price information was available, values were determined either by literature research or by using a cost function (Barchmann et al. 2016). The figures for other investments are generally derived from literature (Welteke-Fabricius 2018) and essentially comprise costs for planning and approvals, grid compatibility testing, the plant certificate in accordance with the Medium Voltage Technical Connection Rule (VDE-AR-N 4110) as well as other technical and structural adjustments in the area of the transformer and the grid connection as well as biogas lines and compressors. For BGP 05, cost estimates were obtained from the operator for further plant-specific investments for a flexibilisation of the plant, which were therefore included into other investments.

For the threefold increase of power generation capacity in scenario B (Table 3) and the fourfold increase of capacity in scenario C (Table 4), the calculation methodology for the additional capacities for installed electrical output, as well as gas and heat storage capacities is the same as for scenario A. It should be noted that, depending on the product range of the CHP manufacturers, the additional installed capacity in scenarios B and C is provided by one or two units. The costs for the necessary capacity expansions at the biogas plants were also determined analogously to scenario A.

Table 3: Expansion and investments of the examined biogas plants in Flex-Scenario B (target value: $Q_P \approx 3$)

Biogas plants	**Unit**	**BGP 01**	**BGP 02**	**BGP 03**	**BGP 04**	**BGP 05**
Additional installed electrical power Flex CHP 1 $P_{el,\ Flex\ CHP\ 1}$	kW	525	400	1,200	355	800
Additional installed electrical power Flex CHP 2 $P_{el,\ Flex\ CHP\ 2}$	kW	-	600	-	355	400
Power quotient after conversion Q_P		3.14	3.01	3.39	2.98	3.30
Expansion of gas storage capacity V_G	m^3	2,500	7,300	5,675	4,200	9,000
Expansion of heat storage volume V_W	m^3	150	100	100	150	50
Investment Flex-CHP 1	EUR	402,790	332,701	720,229	305,926	525,000
Investment Flex-CHP 2	EUR	-	442,432	-	305,926	332,701
Investment in new gas storage facility	EUR	60,389	100,231	88,502	76,579	171,734
Investment in additional heat storage tank	EUR	105,000	76,821	76,821	105,000	54,314
Other investments	EUR	273,000	273,000	273,000	273,000	499,750
Investments Total	EUR	841,179	1,225,186	1,158,552	1,066,432	1,583,500

Table 4: Expansion and investments of the examined biogas plants in Flex-Scenario C (target value $Q_P \approx 4$)

Biogas plants	Unit	BGP 01	BGP 02	BGP 03	BGP 04	BGP 05
Additional installed electrical power Flex CHP 1 $P_{el,\ Flex\ CHP\ 1}$	kW	800	400	1,560	530	800
Additional installed electrical power Flex CHP 2 $P_{el,\ Flex\ CHP\ 2}$	kW	-	1,200	-	530	1,169
Power quotient after conversion Q_P		4.23	4.19	4.09	3.81	4.74
Expansion of gas storage capacity V_G	m^3	3,000	7,300	6,275	5,300	9,000
Expansion of heat storage volume V_W	m^3	150	100	150	150	80
Investment Flex-CHP 1	EUR	541,600	332,701	866,110	405,483	525,000
Investment Flex-CHP 2	EUR	-	720,229	-	405,483	707,099
Investment in new gas storage facility	EUR	65,526	100,231	92,976	85,606	171,734
Investment in additional heat storage tank	EUR	105,000	76,821	105,000	105,000	67,870
Other investments	EUR	375,000	375,000	375,000	375,000	588,500
Investments Total	EUR	1,087,126	1,604,983	1,439,086	1,376,571	2,060,203

Results and discussion

The results of the economic analysis were embedded in the “BioFlex” tool box. Table 5 shows important information for the transition of the biogas plants into the EEG follow-up period (EEG 2.0). It shows the tender dates, that represent the optimal window of opportunity for participation in the tenders to ensure a seamless transition to the follow-up period for the respective plant.

Table 5: Time frames for the participation in a tender under EEG 2017 for the examined biogas plants

Biogas plants	BGP 01	BGP 02	BGP 03	BGP 04	BGP 05
End of EEG remuneration period	31.12.2031	31.12.2026	31.12.2027	31.12.2029	31.12.2027
Possible tender dates	2029 / 2030	2024 / 2025	2025 / 2026	2027 / 2028	2025 / 2026
maximum bid price ($G_{max,el}$) under EEG 2017 in EUR ct kWh_{el}^{-1}	14.85 / 14.70	15.76 / 15.60	15.60 / 15.45	15.30 / 15.15	15.60 / 15.45

Taking into account the transition periods pursuant to § 39f (2) EEG 2017, this period includes the tendering dates that are two or three years before the end of the 20-year EEG remuneration period. With regard to the annual degression rate of the maximum bid prices of 1 %, participation in the tendering procedure under the EEG 2017 at the earliest possible date, in combination with the best possible utilisation of the remuneration phase EEG 1.1, should be considered. For BGP 04 and in particular for BGP 01, the relatively late expiration of the EEG remuneration means, that the maximum price degression for these biogas plants makes it difficult to continue operating them economically sufficiently, even at relatively low costs in EEG 2.0.

Table 6 shows, according to current knowledge, the minimum bid prices for the biogas plants, that they would need to acquire in a tender, to ensure a continued operation at a cost-covering level during the period of the EEG follow-up period. In conjunction with the maximum bid prices of the respective tenders, the following ranges for the submission of bids result.

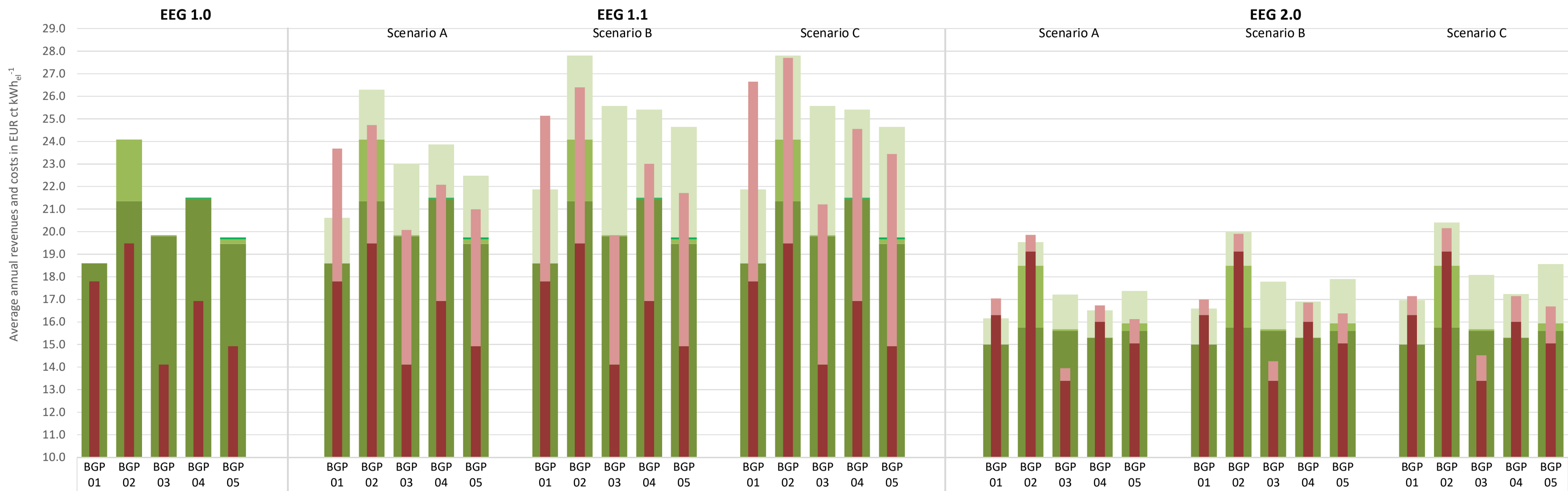
Table 6: Bid prices in the tender for a cost-covering operation in the period EEG 2.0

Biogas plants	**BGP 01**	**BGP 02**	**BGP 03**	**BGP 04**	**BGP 05**
cost-covering minimum bid price* scenario A in EUR ct kWh_{el}^{-1}	15.89	16.08	12.34	15.52	14.35
cost-covering minimum bid price* scenario B in EUR ct kWh_{el}^{-1}	15.40	15.68	12.07	15.25	14.07
cost-covering minimum bid price* scenario C in EUR ct kWh_{el}^{-1}	15.18	15.51	12.03	15.21	13.72

*Deduction of revenues from heat sales and additional revenues from flexibilisation from the LCOE in EEG 2.0

It can be observed, that BGP 01 would not be able to participate with its minimum bid price in any of the optimal tender dates. For BGP 02 and BGP 04, participation in the earliest possible tender would only be economically viable with a performance quotient of $Q_P \approx 3$ or higher. If these plants wait another year before participating in the tender, the further degression of the maximum bid price means that BGP 02 can only submit a cost-covering bid with a power quotient of $Q_P \approx 4$ and BGP 04 cannot even submit a cost-covering bid at all. For BGP 03 and BGP 05, all scenarios result in bid price ranges that are below the maximum bid price for any of the possible tenders. Therefore, these two biogas plants have the opportunity to bid successfully by submitting a bid below the highest bid price, even in a highly competitive tender, and thus to switch to the follow-up remuneration.

A closer look at the results in Figure 3 below shows that the biogas plants, which can be transferred successfully to the follow-up period in all scenarios while covering costs, are already operated with comparatively low LCOE in EEG 1.0 remuneration period. For BGP 03 and BGP 05 these are 14.11 EUR ct kWh_{el}^{-1} and 14.93 EUR ct kWh_{el}^{-1}. BGP 01, on the other hand, has LCOE of 17.79 EUR ct kWh_{el}^{-1} in that period. High LCOE do not necessarily mean an economic loss situation in a possible follow-up period, as can be illustrated by the example of BGP 02. Here the LCOE, excluding credits from heat marketing, total 19.49 EUR ct kWh_{el}^{-1} in the EEG 1.0 section. However, these are largely compensated for by heat revenues, which means that the biogas plant is economically much better positioned than BGP 01, which does not acquire external heat revenues.



EEG 1.0

	BGP 01	BGP 02	BGP 03	BGP 04	BGP 05
Additional revenues flexibilisation*	0.00	0.00	0.00	0.00	0.00
Revenues from provision of balancing power	0.00	0.00	0.00	0.05	0.08
Revenues from external heat sales	0.00	2.73	0.04	0.00	0.21
EEG remuneration**	18.60	21.35	19.80	21.46	19.45
Additional costs flexibilisation***	0.00	0.00	0.00	0.00	0.00
Costs without additional costs flexibilisation****	17.79	19.49	14.11	16.93	14.93

EEG 1.1

	Scenario A					Scenario B					Scenario C				
	BGP 01	BGP 02	BGP 03	BGP 04	BGP 05	BGP 01	BGP 02	BGP 03	BGP 04	BGP 05	BGP 01	BGP 02	BGP 03	BGP 04	BGP 05
Additional revenues flexibilisation*	2.01	2.21	3.16	2.35	2.73	3.27	3.73	5.73	3.90	4.90	3.27	3.73	5.73	3.90	4.90
Revenues from provision of balancing power	0.00	0.00	0.00	0.05	0.08	0.00	0.00	0.00	0.05	0.08	0.00	0.00	0.00	0.05	0.08
Revenues from external heat sales	0.00	2.73	0.04	0.00	0.21	0.00	2.73	0.04	0.00	0.21	0.00	2.73	0.04	0.00	0.21
EEG remuneration**	18.60	21.35	19.80	21.46	19.45	18.60	21.35	19.80	21.46	19.45	18.60	21.35	19.80	21.46	19.45
Additional costs flexibilisation***	5.90	5.24	5.97	5.15	6.07	7.34	6.91	5.70	6.08	6.79	8.86	8.21	7.10	7.63	8.52
Costs without additional costs flexibilisation****	17.79	19.49	14.11	16.93	14.93	17.79	19.49	14.11	16.93	14.93	17.79	19.49	14.11	16.93	14.93

EEG 2.0

	Scenario A					Scenario B					Scenario C				
	BGP 01	BGP 02	BGP 03	BGP 04	BGP 05	BGP 01	BGP 02	BGP 03	BGP 04	BGP 05	BGP 01	BGP 02	BGP 03	BGP 04	BGP 05
Additional revenues flexibilisation*	1.16	1.05	1.54	1.21	1.43	1.60	1.50	2.12	1.60	1.96	1.96	1.91	2.42	1.94	2.62
Revenues from provision of balancing power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Revenues from external heat sales	0.00	2.73	0.07	0.00	0.34	0.00	2.73	0.07	0.00	0.34	0.00	2.73	0.07	0.00	0.34
EEG remuneration**	15.00	15.76	15.60	15.30	15.60	15.00	15.76	15.60	15.30	15.60	15.00	15.76	15.60	15.30	15.60
Additional costs flexibilisation***	0.74	0.73	0.56	0.72	1.08	0.69	0.78	0.87	0.85	1.33	0.84	1.02	1.12	1.14	1.64
Costs without additional costs flexibilisation****	16.31	19.13	13.39	16.01	15.04	16.31	19.13	13.39	16.01	15.04	16.31	19.13	13.39	16.01	15.04

* *EEG 1.1:* Flexibility bonus + additional revenues power exchange EPEX Spot, *EEG 2.0:* Flexibitlity surcharge + additional revenues power exchange EPEX Spot

** *EEG 1.0 + EEG 1.1:* EEG remuneration including bonuses, *EEG 2.0:* EEG remuneration without bonuses assuming a successful bid at the maximum bid price on the earliest possible tendering

*** *EEG 1.1:* Investment and maintanance flexibilisation, *EEG 2.0:* Maintanance flexibilisation

**** *EEG 1.0 + EEG 1.1:* : Investment and maintanance existing biogas plant + consumption, operating and other costs existing biogas plant, *EEG 2.0:* Revaluation (20 % of initial investment) and maintanance existing biogas plant + consumption, operating and other costs existing biogas plant

Figure 3: Average annual revenues and costs of the biogas plants in the three time periods

In general, it can be stated that in the remuneration period EEG 1.1, a significant increase in both revenues and costs can be observed for all five biogas plants compared to the remuneration period EEG 1.0. This is due to the fact, that the costs for flexibilisation are depreciated during this period. In addition, the use of the flexibility bonus will increase revenues, in some cases significantly. In the follow-up period EEG 2.0, the revenues and costs of all biogas plants reduce. Revenues get smaller in particular due to the discontinuation of the flexibility bonus, whereby part of this can be compensated by the flexibility surcharge. In addition, the maximum bid prices limit the revenues that can be generated through electricity marketing. In all the biogas plants, there is still potential for increasing the use of external heat marketing, which could generate additional revenues. On the cost side, as explained in Chapter 2.2, the expenditure on flexibilisation is limited to maintenance in the follow-up period EEG 2.0. However, the biogas plants are reassessed due to structural and technical replacement investments, that are 20 % of the initial investment volume.

Figure 4 shows the annuities in the EEG 2.0 section of the five biogas plants in the three considered scenarios. The annuities represent the average annual surplus or deficit that the biogas plants generate over a specific time frame. In this case, the period under consideration comprises the 10-year follow-up period after the end of the 20-year EEG remuneration period, assuming a seamless transfer and successful participation in the first possible tender with submission of the maximum bid price. For all plants, a more positive economic picture emerges in the scenarios with increasing electrical capacity of the CHP. This is primarily due to the economies of scale of the investment in flexibilisation, especially for the CHP units, so that the additional revenues from the flexibility bonus and flexibility surcharge in the scenarios B and C have a greater impact on economic efficiency than the corresponding additional costs. This effect has already been observed in similar investigations, whereby certain series of CHP manufacturers in certain dimensions show an economic optimum in the magnitude of P_{el} = 2 MW (Wasser 2018). Only two of the biogas plants under consideration (BGP 03 and BGP 05) can expect an average annual surplus in the follow-up period in all of the three scenarios. For BGP 02 and BGP 04, the effects of the economies of scale described above result in a positive total annuity in the follow-up period only for the scenarios with at least a threefold oversizing of the electrical output of the CHP. By submitting the maximum bid price on the first possible tender BGP 01 cannot continue an economic operation in any of the scenarios under the framework conditions assumed in the calculation.

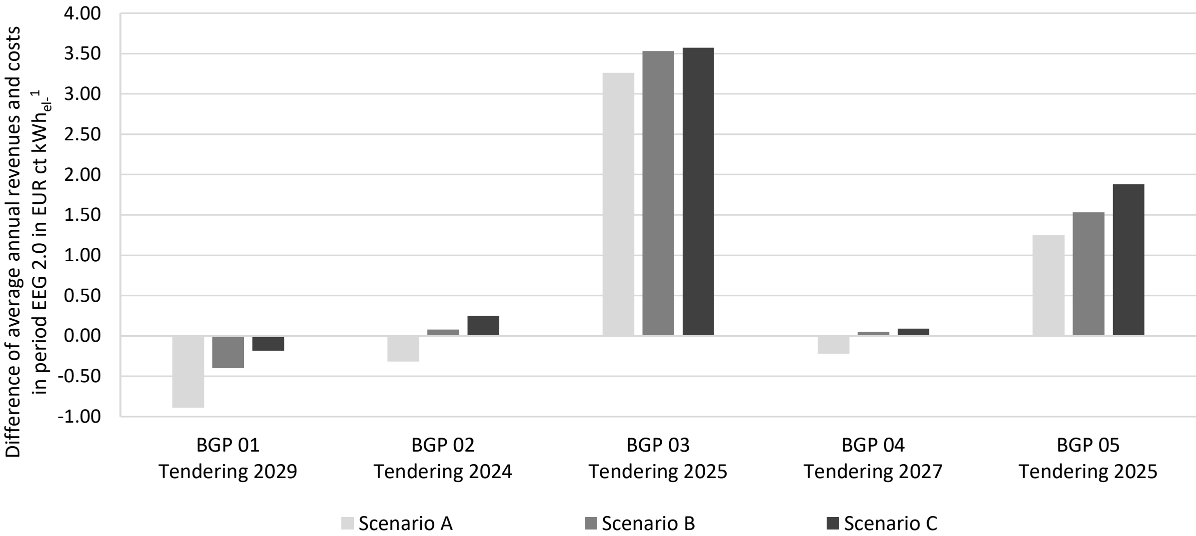


Figure 4: Total annuities of the biogas plants in the EEG 2.0 period in the case of successful participation in the tendering procedure with submission of the respective maximum bid price

In the following, the presented results will be classified critically within the context of the methodology of the economic analysis. As part of the economic analysis the existing CHP units undergo a general overhaul after 65,000 hours of operation and are replaced by a new CHP unit with the same installed electrical output after a total of 95,000 hours of operation. This procedure is not very practical, especially for smaller engines. Especially in the case of high CHP capacity, it is quite conceivable that a small CHP unit will be taken out of operation at the end of its technical lifetime without a replacement investment. In this case, the total freed-up power generation capacity can be transferred to the relatively new and more efficient CHP units in flexible operation mode, which should simultaneously increase the total annual electricity output and thus the efficiency of the biogas plant. Through the decrease of the power quotient Q_P, the biogas plant will, in this case, lose part of the flexibility surcharge corresponding to the capacity of the phased out CHP. There is also a negative effect on the additional revenues that biogas plants can generate at EPEX Spot. As the daily scheduled operation of the CHP unit increases in time with a smaller CHP, electricity is then provided proportionately at less expensive prices, which slightly reduces the additional revenue.

The costs for the CHP units are calculated without residual value at the end of the considered period. However, as they are operated in a flexible mode of operation, the technical lifetime of the existing CHP units or their replacement units and the flexible CHP units can exceed the usual depreciation period of 6 to 8 years. The operating hours and thus the wear and tear of the technical components therefore remain much lower, which is why a residual value for the corresponding CHP units could still be taken into account here.

Conclusions

It can be generally stated, that for all five biogas plants, on the basis of the calculations carried out and under the current legal framework conditions, the fourfold oversizing of the CHP capacity ($Q_P \approx 4$) should be preferred against flexibility options with a lower Q_P, as this is the economically most viable option. This is mainly due to the higher additional revenues from state subsidies in the form of flexibility bonus and flexibility surcharge, with comparatively fewer investment requirements for flexibility due to the degression of the specific costs for the CHP plants. Operators whose biogas plants already have high electricity generation costs will find it very difficult to realise an economic operation of their plant in the 10-year follow-up period under the given maximum bid limits. This is mostly due to the below-average size of such biogas plants or the use of expensive substrates, and the inability to refinance the flexibilisation of the additional CHP capacity via the flexibility bonus.

By switching from expensive renewable raw materials to cheaper agricultural residues and waste materials and by increasing the external use of heat, there is potential scope to improve the profitability of the plant in terms of both revenues and costs. A generally good structural and technical condition of a biogas plant, as the necessary reinvestments as well as maintenance and servicing intervals have already been permanently taken into account during the 20-year remuneration period (EEG 1.0 and EEG 1.1), prevents high maintenance investments at the beginning of the follow-up period EEG 2.0, which also increases the economic sustainability of the biogas plant. Possible legal tightening regarding the operation of the biogas plant in terms of plant safety, more frequent maintenance cycles including their official controls, stricter threshold values with regard to engine emissions etc. have a cost-driving effect.

In general, it should be emphasised that the calculations were based on the maximum bid prices from the earliest possible tender of the respective biogas plants. In particular, for those biogas plants, that are eligible for later tender participation than those plants considered in this paper, a successful switch to the tendering regime under EEG 2017 could become impossible due to increasing competition in the tendering rounds and the tender corridors that have not yet been legally established until after 2022. Depending on the future design of the bid volumes, it may be necessary to bid significantly below the minimum bids presented in this paper in order to ensure that the bids are successfully awarded. This uncertainty should always be considered in a risk analysis for the continuation of operation of a biogas plant. However, as there are currently no legal requirements regarding the maximum tender volumes for biomass plants after 2022 (cf. Section 28 (3) EEG 2017), no reliable analysis of this problem can be made at this stage. In order to circumvent this problem and to increase the chances of winning a contract, it is still conceivable that biogas plants will bid in a tender even before the optimal participation period. If a successful bid is submitted and more than 36 months elapse between the announcement of acceptance of the bid and the end of the 20-year EEG remuneration period, a change to the follow-up remuneration must be made ahead of time. In this case, the shortening of the EEG 1.1 remuneration period leads to the loss of remuneration claims from the 20-year EEG remuneration. In the context of a diversification of entrepreneurial risks, it can therefore be derived that operators of a biogas plant should always include possible alternative business areas for further operation in their planning.

Another legal development is the new version of the Renewable Energies Directive (RED II). This EU directive, which was adopted in 2018, will come into force in June 2021. In general, it can be stated at this point that RED II provides for an extension of the sustainability requirements for the future electricity and heating sectors (Daniel-Gromke et al. 2020). The recast generally stipulates, among other things, that at least 32 % of energy consumption in the European Union in the electricity, heating and transport sectors should come from renewable energies by 2030. Annex VI of RED II already contains standard values for greenhouse gas savings in the supply of electricity from biogas (Renewable Energy Directive 2018). These innovations thus go beyond the previous regulations and legal requirements based on the currently valid EU RED. In general, RED II does not define any explicit criteria regarding the operation of (flexible) biogas plants and air pollutants apart from the proof of a defined GHG reduction. Currently, RED II still has to be transposed into national legislation. Which concrete measures, e.g. in the form of structural or technical retrofitting, will have to be taken by biogas plant operators in the future remains to be seen.

According to a new decision of the Clearing House EEG of 17 September 2019, the flexibility of satellite locations of biogas plants can still be increased. The position of the Clearing House EEG is that a newly added flexible CHP unit at the location of the satellite CHP unit is part of the system and thus forms a joint system within the meaning of § 3 no. 1 EEG 2017. This means that the flexible CHP unit is currently entitled again for the flexibility bonus (Clearing House EEG 2019). Previously, in April 2019, the Regional Court of Frankfurt/Oder had decided that the flexibilisation of satellite locations of biogas plants through the expansion of CHP capacities is generally not permitted. Since the ruling of the Regional Court of Frankfurt/Oder does not constitute a legally valid decision, grid operators and auditors can use the decision of the Clearing House EEG as a basis. A decision by the supreme court on this issue is currently still pending, which is why, according to the recommendation of the Clearing House EEG, each operator should carry out an individual case examination. This should be carried out with the responsible grid operator before the start of the measure in order to ensure that the flexibility bonus is paid out permanently until the end of section EEG 1.1. A final agreement in this matter on making satellite locations of biogas plants more flexible would create the greatest possible degree of legal certainty and binding force for both biogas plant operators and network operators. If a decision by the highest court were to result in a contrary view to that of the Clearing House EEG in the future, this would only apply to future flexibilisation projects (Neumann 2019). The current legal framework conditions must be seen as a potential investment risk, as the claim to the flexibility bonus under the EEG 2017 for the flexibilisation of satellite locations for biogas plants could be dropped in the future. This risk should therefore be considered by each operator at an early stage in investment planning.

Furthermore, the continued operation of a biogas plant over the 20-year remuneration period must always be considered in the context of the entire agricultural business. Even in the case of a marginal economic loss in the biogas sector, the positive effects, for example from the processing of the liquid manure produced or the use of heat at the site, can represent an economic advantage in the overall balance of the agricultural business. For example, possible cost savings in manure spreading or opportunity costs for heat supply must be taken into account, which may compensate for the deficit in revenues from EEG remuneration.

Ultimately, it should be noted that, without a continuation of the tender corridors beyond 2022 in the course of a new amendment to the EEG, it is currently not possible to make a reliable statement on the future procedure for determining subsidies. The biogas plants under consideration would have to participate in the tenders in the second half of the 2020s for a seamless transition to the follow-up remuneration under the current regulations. At his point in time, it is not possible to make a final assessment as to whether these will still take place in their present form or on what legal basis remuneration subsidies for biomass plants will be granted in future.

References

Barchmann, T.; Mauky, E.; Dotzauer, M.; Stur, M.; Weinrich, S.; Jacobi, H.F.; Liebetrau, J.; Nelles, M.I. (2016): Erweiterung der Flexibilität von Biogasanlagen – Substratmanagement, Fahrplansynthese und ökonomische Bewertung. Landtechnik 71(6), S. 233–251, DOI: https://doi.org/10.15150/lt.2016.3146

BEE Bundesverband Erneuerbare Energie e. V. (2019): Positionspapier – Vorschlag für eine Weiterentwicklung der Festlegung der BNetzA zu den Ausschreibungsbedingungen und Veröffentlichungspflichten für Sekundärregelung & Minutenreserve. https://www.bee-ev.de/fileadmin/Publikationen/Positionspapiere_Stellungnahmen/BEE/BEE_PosPapier_Mischpreisverfahren.pdf, accessed on 10 Apr 2019

BNetzA (2019a): Statistiken zum Ausschreibungsverfahren zur Ermittlung der finanziellen Förderung von Biomasse-Anlagen nach dem Erneuerbaren-Energien-Gesetz (EEG). https://www.bundesnetzagentur.de/DE/Sachgebiete/ElektrizitaetundGas/Unternehmen_Institutionen/Ausschreibungen/Biomasse/BeendeteAusschreibungen/BeendeteAusschreibungen_node.html, accessed on 10 Nov 2019

BNetzA (2019b): Pressemitteilung – Förderdeckel für zusätzlich installierte Biomasseanlagen erreicht. https://www.bundesnetzagentur.de/SharedDocs/Downloads/DE/Allgemeines/Presse/Pressemitteilungen/2019/20190831_Biomassedeckel.pdf?__blob=publicationFile&v=3, accessed on 10 Nov 2019

Clearingstelle EEG (2019): Schiedsspruch 2019/22, RELAW GmbH – Gesellschaft für angewandtes Recht der Erneuerbaren Energien, https://www.clearingstelle-eeg-kwkg.de/sites/default/files/2019-10/Schiedsspruch_2019_22_2.pdf, accessed on 16 Nov 2019

Daniel-Gromke, J.; Rensberg, N.; Denysenko, V.; Barchmann, T.; Oehmichen, K.; Beil, M.; Beyrich, W.; Krautkremer, B.; Trommler, M.; Reinholz, T.; Vollprecht, J.; Rühr, C. (2020): Optionen für Biogas-Bestandsanlagen bis 2030 aus ökonomischer und energiewirtschaftlicher Sicht. In: UBA-FB V 1.3 "Erneuerbare Energien" TEXTE 24/2020, Dessau-Roßlau, Januar 2020, ISSN 1862-4804, https://www.umweltbundesamt.de/sites/default/files/medien/1410/publikationen/2020-01-30_texte_24-2020_biogas2030.pdf, accessed on 13 Mar 2020

Dotzauer, M.; Pfeiffer, D.; Lauer, M.; Pohl, M.; Mauky, E.; Bär, K.; Sonnleitner, M.; Zörner, W.; Hudde, J.; Schwarz, B.; Faßauer, B.; Dahmen, M.; Rieke, C.; Herbert, J.; Thrän, D. (2019): How to measure flexibility – Performance indicators for demand driven power generation from biogas plants, In: Renewable Energy 134, 2019, S. 135–146, DOI: 134. 135-146. 10.1016/j.renene.2018.10.021

Dotzauer, M.; Kornatz, P.; Siegismund, D. (2018): Bewertung von Flexibilisierungskonzepten für Bioenergieanlagen - Wirtschaftlichkeitsbetrachtungen für sieben Anlagenbeispiele, Agentur für Erneuerbare Energie – AEE; https://www.unendlich-viel-energie.de/media/file/2391.DBFZ_Bewertung_von_Flexibilisierungskonzepten_fuer_Bioenergieanlagen_jun18.pdf, accessed on 9 Apr 2019

Dotzauer, M.; Lauer, M.; Schneider, J. (2016): Servant of Two Masters? Trade-Offs for Agricultural Biogas Plants Between Flexible Power Generation and Heat Cogeneration, In: Papers of the 24th European Biomass Conference and Exhibition, 2016, S. 1619–1622, DOI: 10.5071/24thEUBCE2016-5AO.9.1

Erneuerbare-Energien-Richtlinie (RED II) (2018): Richtlinie (EU) 2018/2001 des Europäischen Parlaments und des Rates vom 11. Dezember 2018 zur Förderung der Nutzung von Energie aus erneuerbaren Quellen, https://eur-lex.europa.eu/legal-content/DE/TXT/HTML/?uri=CELEX:32018L 2001&from=EN, accessed on 16 Nov 2019

EPEX SPOT SE (2018): Marktdaten Day-Ahead-Auktion. EPEX SPOT SE. Paris. https://www.epexspot.com/de/marktdaten/dayaheadauktion, accessed on 3 Mar 2019

Fachverband Biogas (2016): Biogasbranche baut Wärmebereitstellung weiter aus, Pressemitteilung vom 03.11.2016, https://www.biogas.org/edcom/webfvb.nsf/id/de-pm-14–16, accessed on 15 Nov 2019

Gesetz über den Ausbau erneuerbarer Energie (Erneuerbare-Energien-Gesetz – EEG 2017), Ausfertigungsdatum: 21.07.2017, Zuletzt geändert am 17.12.2018, Anlage 3 – Voraussetzungen und Höhe der Flexibilitätsprämie Nr. I.5, https://www.gesetze-im-internet.de/eeg_2014/EEG_2017.pdf, accessed on 6 Mar 2019

Herbes, C.; Halbherr, V.; Braun, L. (2018): Factors influencing prices for heat from biogas plants. In: Applied Energy 221, pp. 308–318. DOI: 10.1016/j.apenergy.2018.03.188

Hoffstede, U.; Stelzer, M.; Hahn, H.; Beil, M.; Krautkremer, B.; Kasten, J.; Beyrich, W. (2018): Vorbereitung und Begleitung bei der Erstellung eines Erfahrungsberichts gemäß §97 Erneuerbare-Energien-Gesetz – Teilvorhaben II a: Biomasse – Zwischenbericht, https://www.erneuerbare-energien.de/EE/Redaktion/DE/Downloads/bmwi_de/bericht-eeg-2-biomasse.pdf?__blob=publicationFile&v=8, accessed on 10 Nov 2019

Karschin, I.; Geldermann, J. (2015): Efficient cogeneration and district heating systems in bioenergy villages. An optimization approach. In: Journal of Cleaner Production 104, pp. 305–314. DOI: 10.1016/j.jclepro.2015.03.086

Lauer, M.; Dotzauer, M.; Hennig, C.; Lehmann, M.; Nebel, E.; Postel, J.; Szarka, N.; Thrän, D. (2017): Flexible power generation scenarios for biogas plants operated in Germany. Impacts on economic viability and GHG emissions. Int. J. Energy Res. 41(1), pp. 63–80. DOI: https://doi.org/10.1002/er.3592

Neumann, Hinrich (2019): Vorerst Entwarnung für Flex-BHKW. top agrar online, https://www.topagrar.com/energie/news/vorerst-entwarnung-fuer-flex-bhkw-11855157.html, accessed on 16 Nov 2019

Statista (2019): Gaspreis nach Verbrauchergruppen in Deutschland in den Jahren 2008 bis 2018, https://de.statista.com/statistik/daten/studie/154961/umfrage/gaspreis-nach-verbrauchergruppe-seit-2006/, accessed on 15 Nov 2019

Sterner, Michael; Stadler, Ingo (Hrsg.) (2017): Energiespeicher – Bedarf, Technologien, Integration. 2. korrigierte und ergänzte Auflage, Springer, Heidelberg, S. 25–49

Strobl, Martin (2017): EEG 2017 – betriebswirtschaftlich eine (neue) Perspektive?, In: KTBL (Hrsg.) Biogas in der Landwirtschaft - Stand und Perspektiven. FNR/KTBL-Kongress vom 26. bis 27. September 2017 in Bayreuth, Darmstadt, KTBL-Schrift 512, 2017, S. 76–91

Strobl, Martin (2018): Gute Fahrpläne erhöhen die Rentabilität. In: Flexible Biogasanlagen, Landwirtschaftsverlag GmbH, Münster-Hiltrup, S. 16–17

VDI Verein Deutscher Ingenieure (2000): VDI 2067 Blatt 1: Wirtschaftlichkeit gebäudetechnischer Anlagen - Grundlagen und Kostenberechnung, in der Fassung vom September 2000

Wasser, Robert (2018): Doppelt oder fünffach: Wie flexibilisieren Sie richtig? In: Flexible Biogasanlagen, Landwirtschaftsverlag GmbH, Münster-Hiltrup, S. 32–35

Welteke-Fabricius, Uwe (2018): Flexibilisierung von Biogasanlagen. Hg. Fachagentur Nachwachsende Rohstoffe e. V. (FNR), Gülzow-Prüzen, S. 44 ff., https://fnr.de/fileadmin/allgemein/pdf/broschueren/Broschuere_Flexibilisierung_Biogas_Web.pdf, accessed on 6 Mar 2019

Authors

M. Sc. Kevin Haensel (former research assistant), **M. Sc. Tino Barchmann, M. Sc. Martin Dotzauer** and **Erik Fischer** are research assistants at the DBFZ Deutsches Biomasseforschungszentrum gemeinnützige GmbH, Torgauer Straße 116, D-04347 Leipzig. E-mail: tino.barchmann@dbfz.de

Dr.-Ing. Jan Liebetrau is head of Consulting and Research at Rytec GmbH, Pariser Ring 37, 76532 D-Baden-Baden

Note

Parts of the present results were published in the context of the research project „ Biogas-Messprogramm III – Teil 1: Faktoren für einen effizienten Betrieb von Biogasanlagen; Teilvorhaben 1: Energiebilanzierung, Flexibilisierung, Ökonomie“ (funding code: 22403515, project sponsor: FNR) funded by the Federal Ministry of Food and Agriculture (Bundesministerium für Ernährung und Landwirtschaft, BMEL) as well as by the project „Ganzheitliche Regelung von Biogasanlagen zur Flexibilisierung und energetischen Optimierung – GAZELLE“ (funding code: 100267056) funded by the Sächsische Aufbaubank – Förderbank (SAB).