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Expanding the flexibility of biogas plants – substrate management, schedule synthesis and economic assessment

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Since the amendment of the German Renewable Energy Act (EEG) in 2012 as well as in the current version (EEG 2014) the parameters for the expansion of renewable energies aim for a stronger market integration of those. Thereby, biogas plants represent a promising option to produce demand-driven energy to compensate differences between energy demand and energy supply caused by irregular sources (e. g. wind and solar). The contribution focuses on the economic assessment of the flexible biogas production by specific feeding in comparison to continuous gas production against the background of a flexible conversion of biogas into electrical power. The required additional demand for gas storage capacity of a model biogas plant is determined by combinations of different feeding regimes and by three optimised power generation schedules. Subsequently, a cost-benefit analysis is conducted to assess the substrate management economically. The developed methodology is especially designed for existing plants and is used for assessing a multi-factorial substrate management as flexibility option. The results show that substrate management is increasingly appropriate to reduce the additional demand for gas storage especially for longer-term planning horizons (above 12 h) regarding schedule organisation. Moreover, the flexible operation allows generating higher marketing revenues on the European Power Exchange (EPEX Spot SE) at low additional costs.

Keywords
Biogas, flexibilisation, substrate management, feeding management, double membrane gas storage, economic efficiency, demand driven operation

In an energy system characterised by fluctuating renewable energies, it is becoming increasingly important to balance the fluctuation of supply and demand through flexible options within the electricity system. “Flexibility can generally be defined as using different technologies to balance the divergence of energy supply and energy demand with respect to time and space” (Trommler et al. 2016). For example, in terms of demand, energy consumption can be controlled and demand can be transferred to times of low load (demand-side management). With respect to supply, additional storage capacities can be created or the operation of power generation plants can be adjusted, i.e. the quantity of the supplied electricity can be tailored to meet demand (Trommler et al. 2016). Of the available renewable energy technologies – besides geothermal plants and hydropower stations – bioenergy plants in general, and biogas plants, in particular, currently enable electricity production to be controlled. Biogas plants can sell electricity on the EPEX Spot SE as well as provide system services such as control energy. For example, the German market for control energy (as a system service for the transmission

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system operators) encompasses P = 833 MW for primary operating reserves, around P = 2,000 MW for positive and negative secondary operating reserves each, and P = 1,700 MW for negative and P = 1,500 MW for positive tertiary operating reserves (50Hertz Transmission GmbH et al. n.d.). The flexibility bonus was implemented only for biogas plants as part of the 2014 Renewable Energy Act in order to incentivise existing plants to provide demand-oriented electricity production. Thus, the question arises as to the flexibilisation concepts that would optimally integrate biogas plants into the evolving energy system in a technical and economical way. Thereby, the flexibilisation potential of the overall plant is determined by the properties of its components. Possible flexibilisation options along the entire production chain are illustrated in Figure 1.

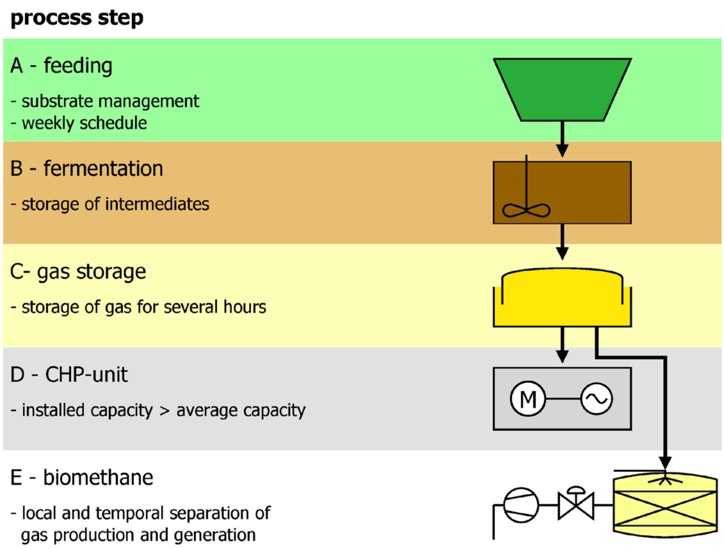
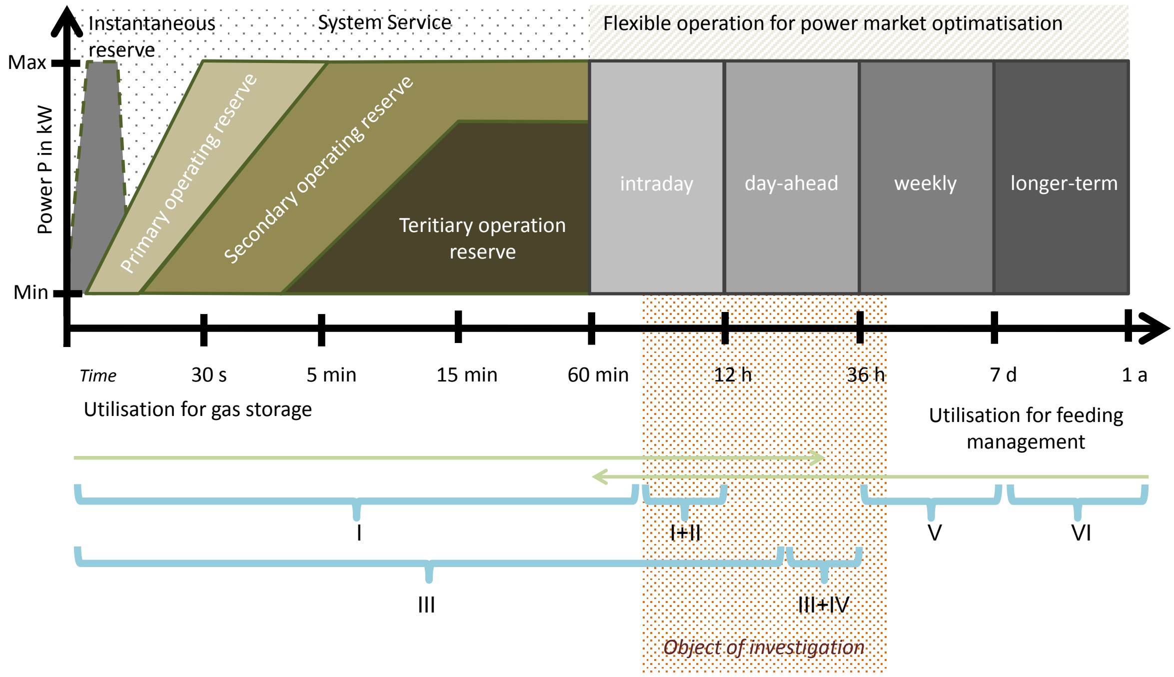


Figure 1: Approaches for a flexible operation of a biogas plant referring to the process chain, source: own diagram, based on Ortwein et al. (2014)

One way to flexibilise existing plants is to specifically influence the biological degradation process through feeding management (Figure 1, A). At the moment, large-scale feeding adjustments are made on a seasonal and monthly basis with the aim of stabilising biogas production and adjusting to seasonal substrate availability and heat sinks (Eckardt 2016). Varying feeding levels and specifically combining different degradable substrates have yet to be used on a large scale. Müller et al. (2011) were able to demonstrate in lab trials that a standard load profile (SLP) can be simulated using variable feeding of stillage. However, stillage is not a very typical substrate for biogas plants. Varying the amount and composition (separating into substrates that degrade quickly, moderately and slowly) in the co-fermentation of beet silage, maize silage and cattle manure was studied on a lab-scale by Mauky et al. (2015). It revealed that gas production is a highly dynamic process (minimum to maximum is 1 to 3) while, at the same time, being a stable process. Further experiments were able to verify process stability for flexible substrate feeding on an industrial scale (Mauky et al. 2016). Thereby, a considerable reduction in the need for additional gas storage capacity (gross storage volume) of up to 45 % could be achieved when feeding was flexible.

Fermentation/gas production (Figure 1, B) in agricultural biogas plants in Germany is most commonly done in continuous stirred-tank reactors (CSTR), followed by plug-flow reactors (PFR) (Witt et al. 2012). The CSTR is considered to be technically straightforward. PFRs have a better utilisation rate and operate with much higher loading rates. Other possible methods include the two-step batch-fixed-bed method, e.g. from Gicon (Grossmann and Hilse 2008). One configuration that has already been tested on a lab scale is described by Wallmann et al. (2010) and Ganagin et al. (2014). It has a continuous upstream hydrolysis step that is followed by methanation in a fixed-bed reactor. The organic acids that form in the separate hydrolysis step are dissolved in a percolate and stored in a buffer tank. From there, the acid-rich percolate is fed to a fixed-bed methane reactor enabling high load change capabilities and low disturbance vulnerability. One advantage of the two-step fermentation process is that, in the methanation step, biogas production can be disrupted for several days and then started up again in a few hours. It should be noted, however, that these approaches require considerable investment and a high technical/equipment outlay. Today gas storage (Figure 1, C) is typically a major component in flexibilising biogas plants. Different types of gas storage designs are used. Local gas utilisation (Figure 1, D) at the site where the biogas is produced is the most frequent form in use. Here, combustion engine-based conversion aggregates are used. The response qualities and the load change stability of these aggregates play a very crucial role in adjusting power generation to meet demands. Additional combined heat and power units (CHP) are needed in order to concentrate power generation into shorter periods of time. Another way to utilise biogas is to purify it into biomethane and to feed this into the natural gas grid (Figure 1, E). This decouples generation and utilisation with respect to time and space. The natural gas grid acts as a storage unit which, in the context of flexibilisation, achieves a strong time-related decoupling of gas production and gas utilisation.

These complex ways of flexibilising plants face a variety of demands made by the energy system. The demands for flexibility differ, for example, depending on the different timescales. Usually, the frequently communicated demand for flexibility in the electricity sector focuses on real-time or short-term needs. This corresponds with the control energy, intraday and spot markets. Regarding the time until delivery of energy certain requirements have to be met by energy producers if they wish to participate in these markets. Figure 2 lists the mandatory deadlines for participating in reserve markets, and summarises the ways to optimise the electricity market.



I	gas storage (GS) without extension	III+IV	GS with extension incl. short-term FM
I+II	GS without extension incl. short-term feeding management (FM)	V	middle-term FM
III	GS with extension	VI	seasonal FM

Figure 2: Scheme for classification of multidimensional feeding management concerning temporal use for different types of operating reserve und flexibilisation for power market optimisation (Source: own diagram, based on Dezera (2016))

Medium-term fluctuations within hours are offset by trading on the EPEX Spot SE electricity exchange. Depending on weather patterns, electricity producers and consumers are also exposed to longer-term fluctuations which induce balancing requirements ranging from several days to several weeks, or on a seasonal scale. These demands also have to be borne in the future by renewable energies following the reduction in the capacities of fossil fuel-based power plants. In order to illustrate the challenges facing biogas plants, different demands for flexibility are schematically listed in Figure 2 with respect to the timeframe of their scope of action.

The overlapping of the different areas of use of feeding management and gas storage as instrument of load transfer is displayed. The implementation of feeding management enables a range of flexibilisation that would otherwise only be satisfied by very large volumes of gas storage (Figure 2, configuration I versus configurations I + II). At the same time, feeding management also allows the available gas storage to better support the flexibility of the system (Figure 2, configurations III + IV). Short-term feeding management for daily and intraday flexibilisation is different from medium-term (V) and seasonal feeding management (IV). This paper focuses on short-term feeding management, covering the area in Figure 2 that is shaded red. The term “flexible feeding”, as used below, shall describe a mode of operation in which the anaerobic degradation process is regulated by specifically influencing feeding and in this way producing the biogas according to demand. This is contrasted by a mode of operation characterised by continuous feeding with a constant gas production. The term multifactorial substrate management has been introduced in the evaluation of flexible feeding with the aim of market-based optimisation. The major factors regulating gas production include:

- Point in time of ration
- Quantity of the ration
- Composition (percentage of substrate) of the ration and its
- Quality and substructure (e.g. through disintegration).

By varying these factors, the biogas process can be influenced to different degrees. This means that very different flexibility needs can be addressed which, in the simplest case, emulate seasonal patterns or which enable short-term adjustments in conversion rates to be made using dynamic process models.

The investigations made in this paper are based on a standard biogas plant that uses a continuous stirred tank reactor (CSTR), agricultural substrates (e.g. cattle manure, maize silage) and onsite conversion of the biogas into electricity. The aim is to study the economic effects of flexible feeding on the schedule structuring of such a sample plant, and to work out the potential for saving on gas storage capacities. A number of papers have already been published that discuss the opportunities and benefits of biogas technology on the electricity and control energy market (Hahn et al. 2014, Hochloff et al. 2014, Grim et al. 2015). However, the effect of flexible gas production based on EPEX-optimised power generation schedules on profitability has not yet been investigated. The process dynamics of anaerobic degradation is fed back to the schedule synthesis using a simplified simulation model. The model's parameters are based on experimental investigations on the flexibility of the biogas process using conventional substrates on an industrial scale (Mauky et al. 2016).

The aim of this article is:

- to work out the interplay between schedule structuring and feeding management in the context of flexibilisation and
- to reveal the cost-benefit ratio by economically assessing flexibilisation through flexible feeding.

Material und methods

An integrated model consisting of 5 components (Figure 3) was used to assess flexible feeding in terms of the revenue potentials when directly marketed, and to determine the gas storage requirements needed to flexibly generate electricity from biogas.

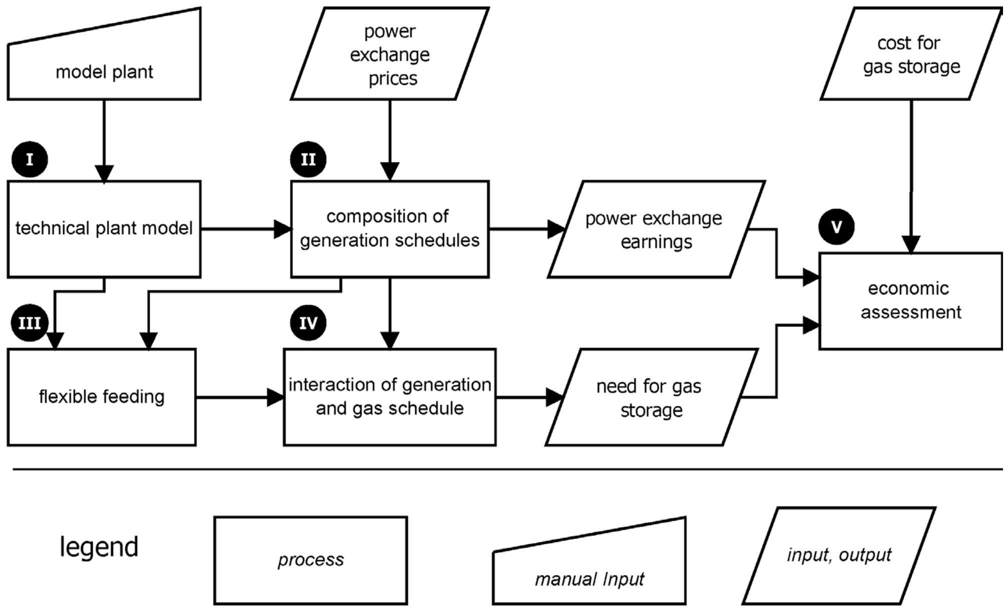


Figure 3: Block diagram of model components (mapped as rectangle processes) for evaluation of flexible feeding

I – Technical plant model

The first component is the technical plant model in which a biogas plant with 457 kW of electric rated power, corresponding to P_{el} = 500 kW of installed electrical capacity at 8,000 full utilisation hours, is represented in a simplified form. This plant produces 4,000,000 kWh of electricity per year. For flexible electricity production it is assumed that the power generation capacity of the model plant is higher than its rated power. The flexibilised model plant has a total electrical power of P_{el} = 1,000 kW consisting of a CHP with P_{el} = 250 kW and an electrical efficiency of η_{el} = 40 %, and a CHP with P_{el} = 750 kW and an electrical efficiency of η_{el} = 42 %.

The cascade is assumed to be made up of two fermenters (CSTR), in other words a main fermenter and a post-digester, each with gross volume of 2,168 m³ and an internal diameter of 25.5 m. The selected substrates are cattle manure and maize silage (30 % to 70 % based on mass). The technically related maximum feeding rate of maize silage is assumed to be 4,500 kg h^{-1}.

The biogas plant model in the baseline scenario has a gross storage volume of 2,200 m³. Both the main fermenter and the post-digester have a gross storage volume for biogas of 1,100 m³ each. The analyses below always refer to the primary energy equivalent of the gas storage volume. The primary energy content of the gas storage is calculated by multiplying the net standard volume with the higher heating value of biogas of 5.19 kWh m^{-3} and deducting 10 % each for the safety margins for the upper and lower filling level limits, and the correction factor to convert operating volumes into standard volumes (1.25). In this example the primary energy equivalent E of the useable gas storage is around 7,300 kWh. The net storage volume therefore refers to the actual gas storage capacity that can be utilised by a biogas plant. The main technical plant parameters for this analysis are summarised in Table 1 both for reference scenario A and for scenarios B to G.

Table 1: Technical plant parameters

Scenarios	Unit	A	B to G
Installed electrical capacity	kW_{el}	500	1,000
Full utilisation hours	$h\ a^{-1}$	8,000	4,000
Electric rated power	kW	457	457
Electrical efficiency η_{el}			
CHP I: P_{el} = 500 kW	%	40	-
CHP II: P_{el} = 250 kW	%	-	40
CHP III: P_{el} = 750 kW	%	-	42
Substrate use (based on mass)			
Maize silage	%	70	70
Cattle manure	%	30	30

II – Synthesis of the power schedule

The model's second component is the synthesis of power generation schedules. Before schedule synthesis was performed, three observable scenarios were established. All three scenarios are based on partially flexible operation of the CHP units of the plant model. The smaller CHP unit, with P_{el} = 250 kW of installed electrical capacity, is run on a continuous basis while the larger CHP unit, with P_{el} = 750 kW, functions as a peak load generating unit operated in a start-stop mode. This mode of operation is typically found in practice; the base-load CHP unit provides control energy and heat sinks while the peak-load CHP unit markets electricity in line with electricity prices (Lauer et al. 2015). By dividing the available primary energy, this constellation produces an average daily run-time for the peak-load unit of 11 h per day or 77 h per week.

The price rank method is used to place the daily or weekly run-times of the peak-load CHP unit at the most expensive hours of the day. The hours with the highest average stock exchange prices are selected for the three optimisation intervals (Figure 4). In the direct marketing model electrical power from biogas plants is primarily traded on the spot market. The input data for the price rank method were therefore the price time series of the European electricity exchange (EPEX Spot SE 2013). The reference year was 2013. Even though there was a drop in price volatilities during the observation period up until 2015, an increase in price fluctuations is expected in subsequent years (Nicolosi 2014). The "standard 24 schedule" is the most straightforward option. It represents the optimal daily schedule for 24 h (Figure 4) averaged over the year.

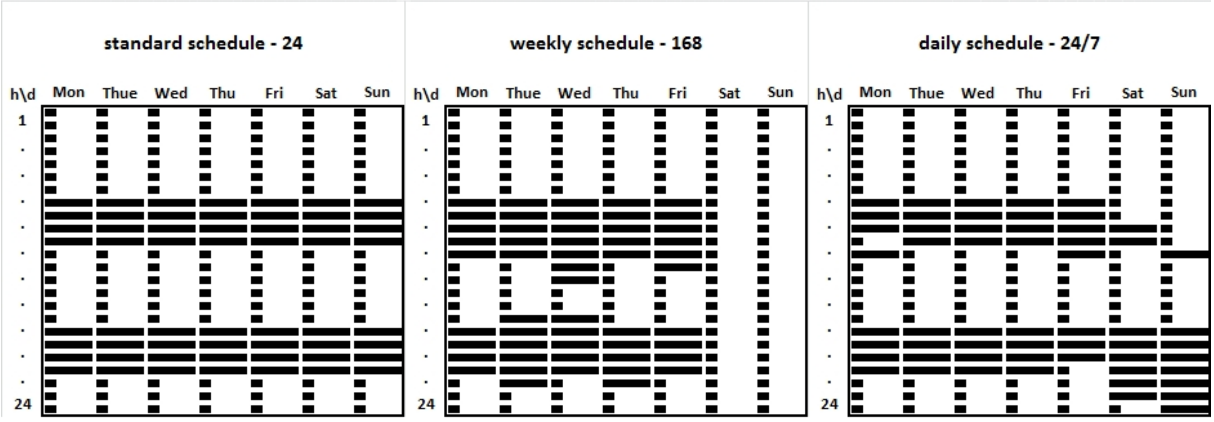


Figure 4: Matrices for one week showing the relative power feed in, 24 rows (h) by 7 columns (d), of 3 schedules (standard schedule, daily schedule, weekly schedule), the shorter bars representing the continuously running combined heat and power unit (CHP-unit, CHP) with 250 kW, the larger bars shows an operating state, where in addition the CHP with 750 kW is in operation

In the "daily 24/7 schedule", the power generation intervals are optimised within the 24 h for each weekday averaged over the year. The daily power generation time of the peak-load CHP unit is constant (Figure 4). The "weekly 168 schedule" optimises the use of the plant throughout the entire average weekly price development for 168 h. Here the daily power generation times of the peak-load CHP unit fluctuate. The weekly schedule exhibits long partial load operation (only the base-load CHP unit runs constantly) as a result of the lower prices on the weekend. These three types of power schedules are then transferred to the model components for flexible feeding for the purpose of varying gas production.

III – Optimising feeding and modelling flexible biogas production

The third model component, which is based on the defined substrates (cattle manure and maize silage) and the power generation schedule from model component II, looks for the optimal feeding regime that fulfils the power generation requirements using the lowest required gas storage capacity. Only the substrate maize silage is varied in time and quantity when feeding is optimised. The weekly amount of substrate is determined in advance and can be distributed throughout the week among the days and within the days into 12 slots (feeding interval every 2 hours). The daily allotment of cattle manure is evenly distributed and fed in intervals of 2 hours due to its slow degradation kinetics and its smaller share in the gas production. Figure 5 schematically shows the model-supported optimisation of the feeding regime, consisting of the main components of process model and optimiser. The aim is to minimise the necessary gross storage volume by flexibilisation of the gas production. Based on the predefined gas utilisation schedule the theoretical timely progression of the gas storage filling level is balanced using the modelled course of the gas production. The process model is based on the Anaerobic Digestion Model No. 1 (ADM1, Batstone et al. 2002), however it has been structurally simplified (Mauky et al. 2016). The method for simplifying it is described by Weinrich and Nelles (2015). The kinetic parameters used are identified based on trials on an industrial scale (Mauky et al. 2016). The resulting maximum gas storage filling level is minimised by iteratively adjusting feeding quantities using an optimisation algorithm. Auxiliary constraints include the feeding rate for each substrate and the quantities of substrate available each week. The application of numerical optimisation was achieved in the software environment Matlab / Simulink R2014a.

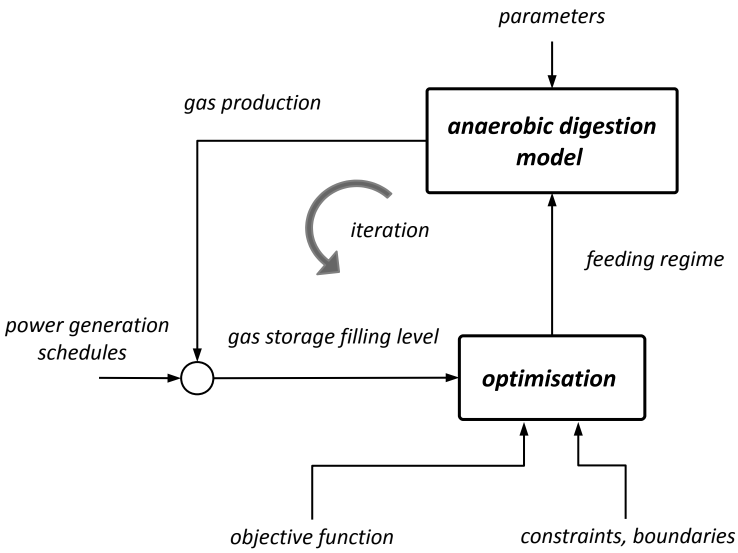


Figure 5: Schematic description of the model-based optimisation of gas production according a power generation schedule

Framework of the investigation – scenario matrix

A total of seven scenarios are produced by comparing continuous feeding with flexible feeding and by taking into account the various power generation schedules and the baseline scenario (standard schedule plant operation without flexibilisation) (Table 2).

Table 2: Scenario matrix for evaluation of the flexible feeding

Schedule	Continuous feeding (CF)	Flexible feeding (FF)
Rated power	A	-
Standard schedule	B	C
Daily schedule	D	E
Weekly schedule	F	G

Scenario A is the baseline or reference scenario. The biogas plant model consists of a CHP unit with an installed electrical capacity of P_{el} = 500 kW. There is no flexibilisation in this scenario. Reference scenario A is not considered in more detail below because it only serves as the starting point for the following scenarios in which the model biogas plant is uniformly flexibilised.

In scenarios B to G the feeding regime (continuous and flexible feeding) is coupled with the electricity generation schedules of the conversion units (standard schedule, daily schedule and weekly schedule). The economic benefit is determined for flexible feeding in scenarios C, E and G and for continuous feeding in scenarios B, D and F. This benefit is reflected in a reduced need for additional gas storage capacities. In the context of the various power schedules, scenario B is compared with C, D is compared with E and F is compared with G. All of the scenarios can be aligned with the short-term feeding management in figure 2. The authors focus on configurations I+II and III + IV since the intraday, day-ahead and sometimes even weekly flexibilisation opportunities can be utilised in order to better optimise existing biogas plants for the electricity market.

IV – Combining electricity and gas schedules

The fourth model component combines electricity and gas schedules. It is used to determine the EPEX revenue which the schedules should achieve, and the gross storage capacity needed for the respective power generation schedules. To do so, the CHP schedules for 8,760 annual hours are merged with the gas requirements resulting from this and the gas production for each respective scenario. The EPEX revenue is dependent on the schedule options described above. Only the additional revenues that, as a result of price-optimised operation, are higher than selling electricity at the annual average rate on the spot market are relevant for the economic assessment. Furthermore, the gross storage requirement varies depending on whether there is continuous gas production through continuous feeding or variable gas production through flexible feeding. The necessary gross storage capacity is determined in the model regardless of the available gas storage capacity in the course of the modelled annual load profile. The difference between the global maximum and minimum in this load profile determines the gross storage volumes needed for the respective model profile. The necessary additional storage volume is calculated by subtracting available storage capacities from the overall storage requirements. If an adjustment is to be made to gas storage in storage vessels, i. e. integrated double membrane gas storage (DMGS), it should be noted that expanding gas storage capacities in existing biogas plants can only be done by replacing the existing storage membrane. A new gas storage unit can be installed e. g. on a fermentation residue storage that has not yet been covered with a storage facility, or an external gas storage facility can be installed in addition to and independently from the existing storage system.

V – Economic assessment

In the fifth model component an economic assessment is conducted based on the identified higher EPEX revenue, the additional gross storage requirements and the ascertained gas storage costs. The following cost considerations are based on integrated and separate/external DMGS units. The terminology is defined by the authors as follows. An integrated DMGS consists of:

- a double-leaf membrane gas storage roof with little gas permeability (SVLFG 2013) which has
- an external, non-stretchable weather protection membrane that is pneumatically preloaded with supporting air and
- a non-stretchable, interior gas storage membrane located above the fermentation area with a retaining system integrated beneath this to store the membrane when the gas storage facility is technically empty.

Stretchable interior gas storage membranes and interior membranes that are mechanically stored using a supporting beam are also sometimes used by industry, however these storage membranes are not considered in this paper. The potential design of an integrated DMGS unit above a CSTR is illustrated in Figure 6.

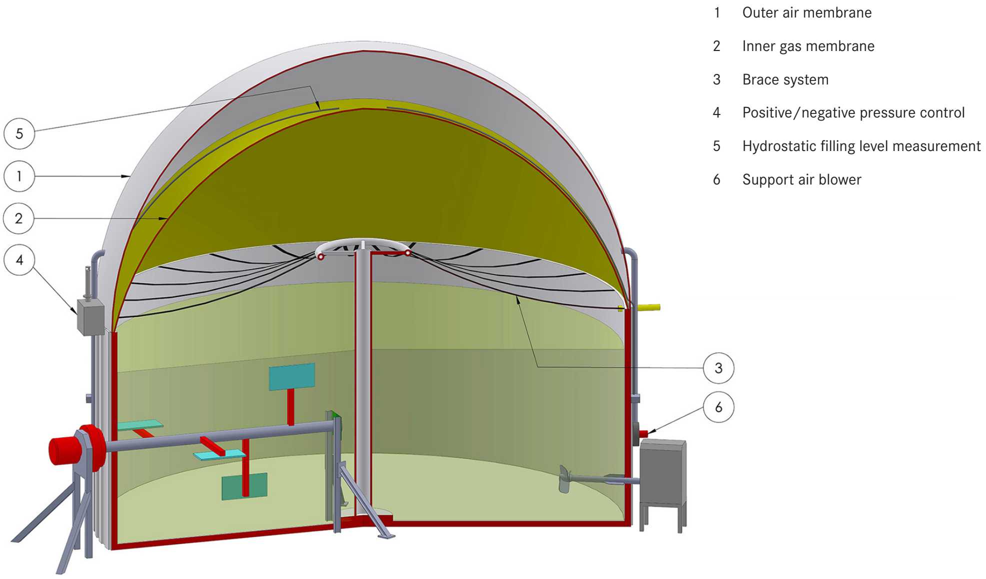


Figure 6: Structure continuous stirred-tank reactor (CSTR) with integrated double membrane gas storage, source: adapted from (Liebetrau et al. 2015)

A separate or external DMGS unit has the same construction as an integrated DMGS unit with the exception that there is no double membrane gas storage roof above the CSTR. Instead it is installed on a separate foundation. The additional external DMGS unit has to be integrated into the already existing gas storage system using the corresponding connections and gas pipelines.

In addition to double-leaf gas storage, other ways of storing biogas in biogas plants include single-leaf gas storage or foil cushion storage which are not considered in this paper.

The costs of integrated and external DMGS units are based on a survey of 5 manufacturers conducted in 2013 and 2015. A total of eleven proposals for integrated DMGS units and four proposals for external DMGS units were received which serve as the basis for the cost calculation. The specific costs for an integrated DMGS unit (connected to storage vessels) are listed below in Figure 7.

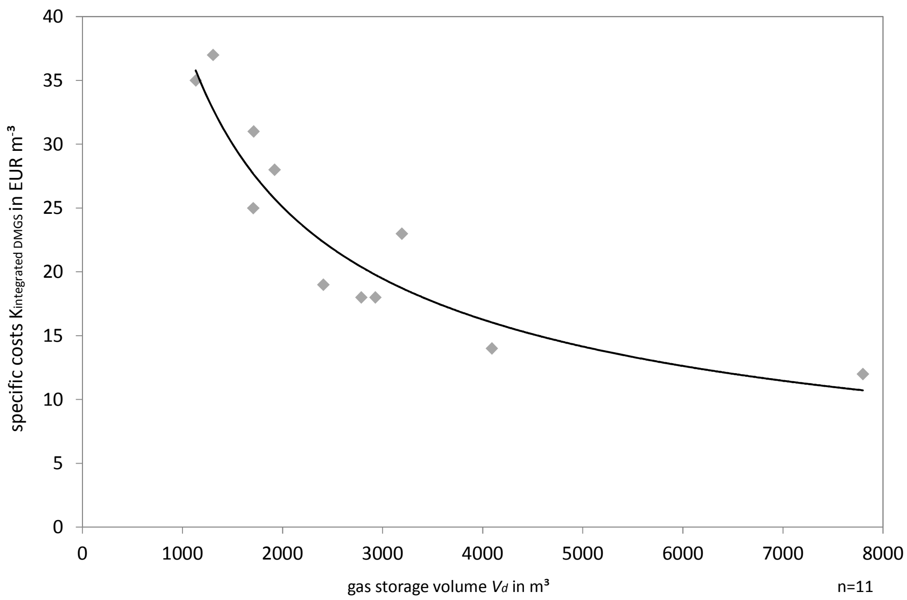


Figure 7: Specific costs of integrated double membrane gas storage on top of the fermenter (n=11)

Based on the manufacturer survey, the cost per cubic meter of an integrated DMGS unit can be estimated using the power function in Equation 1 below:

$$K_{\text{integrated DMGS}} = 2{,}889 \cdot V_d^{-0.624} \quad \text{(Eq. 1)}$$

$K_{\text{integrated DMGS}}$	Specific costs of an integrated DMGS unit in EUR m^{-3}
V_d	Gross storage volume of an integrated DMGS unit in m^3

In order to assess the costs of an external DMGS unit, which is also based on a storage membrane system and a maximum of 600 m^3 h^{-1} for the filling or extraction of gas, proposals were received for storage units with a gross storage volume of 5,000 m^3 to 15,000 m^3. The resulting cost function per cubic meter is reflected in Equation 2.

$$K_{\text{external DMGS}} = 456 \cdot V_e^{-0.412} \quad \text{(Eq. 2)}$$

$K_{\text{external DMGS}}$	Specific costs of an external DMGS unit in EUR m^{-3}
V_e	Gross storage volume of an external DMGS unit in m^3

Not included in Equation 2 are the costs for the footing, construction of the strip foundation, and the pipework for connecting the external DMGS to the existing gas storage system. These are assumed to be a flat rate of € 15,000 for an external DMGS unit with a gross storage capacity of 7,300 m^3 (Table 3) (Wiedau, H.; Sattler Ceno Biogas GmbH, telephone conversation on 2 December 2015). Other costs, such as transport, crane and installation supervision (installation including cost of labour, installation supervision, leak test and commissioning) are elements of the cost function. Scaffolding construction, supply of construction site electricity and other assembly work can produce slight additional costs. Since these costs are not always incurred, they are not included in the results. All of the prices are net prices and exclude statutory value added tax.

In order to determine the specific investment requirements for an integrated or external DMGS unit, it is necessary to enter V_d or V_e from Table 3 into Equation 1 or Equation 2 respectively. To determine the absolute investment requirement, Equation 1 or Equation 2 has to then be multiplied by V_d or V_e respectively. Based on the manufacturer surveys, an average lifetime of 8 years is assumed for integrated and external DMGS units. This means that the observation period of the economic assessment is also 8 years. Thus, the costs for retrofitting or expanding the existing gross storage volume (absolute investment requirement) are only incurred once. Other observation periods based on the remaining term of the existing biogas plant are also possible. Longer lifetimes would mean there would be replacement investments for gas storage membranes and protective membranes for the integrated and external DMGS units. Running costs, for example potential maintenance work and electricity costs for the supporting air blower, are not considered in the economic assessment since they are difficult to quantify and do not incur necessarily.

The costs for retrofitting integrated and external DMGS units are discounted at 8 years and compared to the additional annual EPEX revenue (reference year 2013). Additional costs for the flexibilisation of biogas plants (e. g. expanding CHP capacity) and income from flexibility premium are explicitly not taken into consideration here, since the power generation schedules are based on a uniform plant configuration and the identified factors thus remain constant. Furthermore, the potential optimisation of control energy revenue is also not regarded since it is outside the object of investigation in Figure 1.

One parameter of assessment is Delta ($\Delta_{E\text{-}K}$), formed by subtracting the annual costs for the absolute investment required to achieve additional gross storage volume from the additional annual EPEX revenue (Equation 3):

$$\Delta_{E\text{-}K} = E_{EPEX\text{-}Mehrerlöse} - K_{DMGS\ absolut} \quad \text{(Eq. 3)}$$

$\Delta_{E\text{-}K}$	Delta of additional revenues and additional costs in EUR a^{-1}
$E_{additional\ EPEX\ revenue}$	additional annual EPEX revenue in EUR a^{-1}
$K_{DMGS\ absolute}$	annual costs of an integrated/external DMGS unit in EUR a^{-1}

Thus, only the effect that continuous or flexible feeding has on the investment required to achieve additional gross storage volumes for different power generation schedules is quantified.

In the assessment approach used to quantify the benefit of optimising flexible feeding regarding reduced gross storage capacities, the expenses for adjusting the permitting and the safety concepts for overbuilding the previous gas storage capacities are not taken into consideration. Furthermore, the requirements of the Major Incidence Ordinance have to be observed when there are 10,000 kg or more of flammable gas involved (around 7,300 m³ raw biogas under standard conditions with 0 °C and 1013,25 mbar with 50 % methane) (Häring 2013). In addition, disposal costs for old components (membrane, wood construction etc.) as part of retrofitting work may be incurred. These are not considered in the cost consideration, however under certain circumstances they can be taken into account.

Thus, fixed costs can be expected when retrofitting or expanding the gas storage capacities of existing biogas plants. The same applies when an external instead of an integrated DMGS unit is chosen for structural reasons, e. g. high wind loads.

Results and discussion

Only the same types of power generation schedules with different feeding regimes are of interest when comparing the results of the modelling. Figure 8 compares the developments in gas requirements, gas production, and the gas storage filling level in the case of continuous and flexible feeding for scenarios B and C, D and E, and F and G.

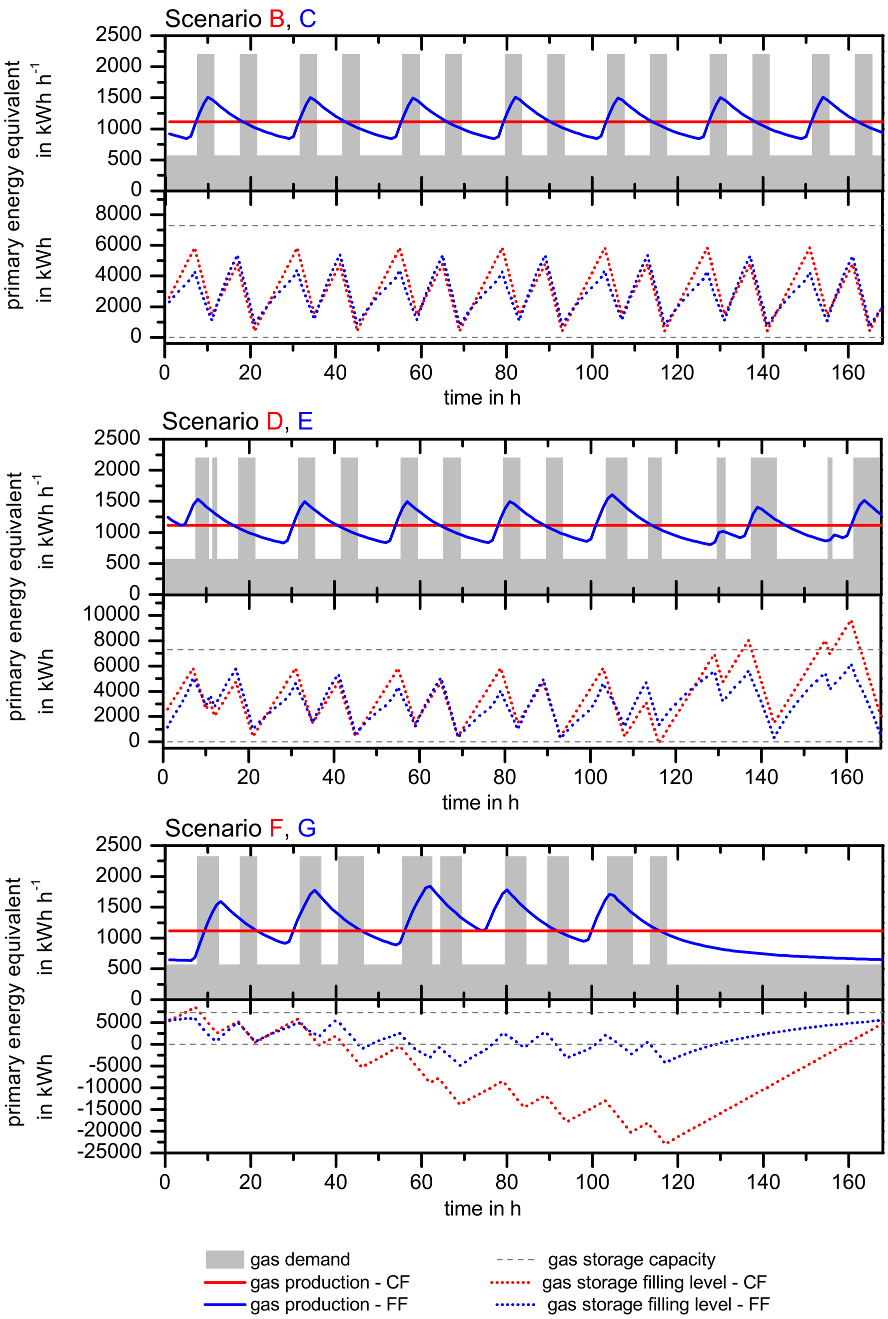


Figure 8: Comparison of continuous feeding (CF) and flexible feeding (FF) for a period of 7 days for different scenarios. Course for gas demand, gas production and gas storage filling level for scenario B vs. C; scenario D vs. E and scenario F vs. G

In the case of a standard schedule with comparably even distribution of the power generation blocks, the gas storage filling level always fluctuates within the permitted limits both for continuous and for flexible feeding. Flexible feeding only leads to the existing gas storage not being utilised so heavily; utilisation is 64 % (scenario C) instead of 74 % (scenario B). In this case, the use of flexible feeding does not provide any notable advantages expect for the fact that the operator can reserve more free storage capacity for unscheduled CHP downtimes when necessary.

As the result of daily power generation schedule optimisation there are larger amplitudes for gas storage filling at weekends due to the trend of pushing the power generation blocks to the second half of the week (Figure 8). When gas production is continuous, the longer break in power generation of peak-load CHP, occurring between Friday afternoon and Saturday morning, leads to a violation of the upper limit for the gas storage filling level (scenario D). When feeding is flexible, this limit violation at weekends can be completely avoided so that, in this case, no additional gas storage is necessary for achieving this power generation schedule (scenario E).

In the case of a weekly schedule, there are very long power generation breaks of peak-load CHP due to the generally low prices on the power exchange at the weekend. The utilisation patterns on work days are essentially similar to those of daily schedule optimization (daily schedule), whereby longer daily power generation intervals can be observed since the primary energy not used on the weekends can be additionally generated during the week and sold at better conditions. Both effects require strong amplitudes in the timing of the gas storage filling level in the case of continuous gas production which could considerably exceed the upper and lower limits. In the case of flexible feeding, these extreme values in the gas storage filling level can be considerably reduced so that, instead of 7,300 m³ (scenario F), only a little more than 1,100 m³ of additional gross storage capacity is needed to achieve the weekly schedule (scenario G).

In all scenarios, the required amount of storage volume in the DMGS unit can be reduced through flexible feeding. The amount of gross storage required by flexible feeding is, on average, 39 % below what is required for continuous feeding if the power generation times of the peak-load CHP are lowered at the weekend.

An overview of the calculation results is summarized in Table 3. In terms of the additional revenue, this revenue increases as the degree of freedom in schedule optimisation increases. Thus, compared to reference scenario A, which has a standard schedule, € 17,902 in additional revenue was achieved in 2013 through plant configuration scenarios B and C. In the case of an annual electricity production of 4,000,000 kWh, this corresponds to additional proceeds of € 0.45 cents per kWh^{-1}. When the schedule is optimised daily (daily schedule), as in scenarios D and E, an additional € 19,572 in absolute terms, and € 0.49 cents per kWh^{-1} in specific terms were achieved. The largest additional revenue was achieved when the schedule was optimised over the entire week (weekly schedule) amounting to € 26,872 in absolute terms or € 0.67 cents per kWh^{-1}. This means that a 50 % higher revenue can be generated than in the case of a standard schedule in which a 24 h schedule repeats on a daily basis. Based on the same plant configuration and using a standard schedule, gross storage requirements can be reduced by a total of 14.1 % from 1,638 m³ in scenario B to 1,407 m³ in scenario C through flexible feeding (Table 3). Since the biogas plant model already has gross gas storage capacities of 2,200 m³ in the baseline scenario, no additional capacities are needed in either of the scenarios.

Table 3: Results table of model calculations – part 1, comparison by pairs of equal schedules for continuous and flexible feeding, specifications concerning gas storage are volumetric; calculations within the model are energetic

Szenarien	Unit	B	C	D	E	F	G
Additional EPEX revenues	€ a^{-1}	17,902	17,902	19,572	19,572	26,872	26,872
Additional revenues towards reference scenario	%	-	-	9.3	9.3	50.1	50,1
Storage demand absolute	m^3	1,638	1,407	2,948	1,796	9,500	3,314
Modelled storage utilisation towards plant configuration of reference scenario A	%	74	64	134	82	432	151
Storage reduction flexible feeding	%	-	-14.1	-	-39.1	-	-65.1
Additional gross storage demand	m^3	0	0	748	0	7,300	1,114
Necessary extension gross storage volume of integrated DMGS V_d	m^3	-	-	1,848	-	-	2,214
Necessary extension gross storage volume of external DMGS V_e	m^3	-	-	-	-	7.300	-
Total available gross storage volume after retrofitting	m^3	2,200	2,200	2,948	2,200	9,500	3,314
Maximal length of storage at average biogas production	h	10	10	13.6	10	44	15.3

More gross storage is needed in scenarios D and E than in scenarios B and C due to the use of a daily schedule. Through flexible feeding (scenario E) gross storage requirements can be reduced from 2,948 m^3 to 1,796 m^3 (39.1 % reduction) compared to continuous feeding (scenario D). While in scenario D a new, larger integrated DMGS unit with a capacity of 1,848 m^3 (Table 3) has to be built on top of the fermenter at a cost of € 48,868 (Table 4), this is not necessary for scenario E since the existing gross storage volume is sufficient. Thus, scenario E that has flexible feeding is preferred over scenario D that has continuous feeding since both have the same potential to achieve additional revenue, but there are no additional costs for converting to an integrated DMGS unit in scenario E.

Table 4: Results table of model calculations – part 2, comparison by pairs of equal schedules for continuous and flexible feeding, specifications concerning gas storage are volumetric; calculations within the model are energetic

Scenarios	Unit	B	C	D	E	F	G
Costs for additional gas storage extension absolute	€	-	-	48,868	-	100,231 [1)]	52,304
Cost savings DMGS at flexible feeding towards continuous feeding absolut	€	-	0	-	48,868	-	47,927
$E_{additional\ EPEX\ revenues}$	€ a^{-1}	17,902	17,902	19,572	19,572	26,872	26,872
$K_{DMGS\ absolute}$ [2)]	€ a^{-1}	-	-	6,109	-	12,529	6,538
Δ_{E-K}	€ a^{-1}	17,902	17,902	13,463	19,572	14,343	20,334

[1)] Incl. 15,000 EUR for footing, foundation and pipe work.
[2)] Depreciation DMGS for 8 years.

The utilisation of a weekly schedule for generating power from biogas in scenarios F and G has to be assessed in a more differentiated way. There is a high need for storage due to the long period of time in which only the CHP with an installed electrical capacity of P_{el} = 250 kW is run at a lower output, and because less biogas is used at weekends. In scenario F this amounts to 9,500 m³ with continuous feeding (Table 3). Thus, the absolute gross storage requirement is 4.3 times the existing gas storage capacity. Due to the high absolute gross storage requirement, an external DMGS unit is built in scenario F. The already existing gas storage capacities on the fermenter or post-digester remain and are not changed in terms of construction. Thus, subtracting the existing gas storage capacity of 2,200 m³, an external gas storage unit measuring 7,300 m³ is additionally required. When a weekly schedule is used, the gross storage requirements of scenario G can be reduced through flexible feeding by 65.1 % over scenario F, resulting in a gross storage volume of 3,314 m³. As this corresponds to a considerable investment savings – under the selected assumption of the biogas plant model – flexible feeding (scenario G) is preferred over constant substrate feeding (scenario F). The cost savings by building a new, integrated DMGS unit measuring 2,214 m³ (Table 3) on the fermenter in scenario G amount to € 47,927 (Table 4) compared to building a new external DMGS unit in scenario F. Thus, the highest annual $\Delta_{E\text{-}K}$ is achieved in scenario G, which is only marginally higher than scenario E.

Conclusions

Flexibly generating power through biogas plants requires a series of technical components on the biogas plant. Furthermore, not every concept of sustainable flexibilisation of existing biogas plants is necessarily economically beneficial compared to the status quo. In terms of the biogas plant's economic results, the technical and conceptual requirements have to be taken into consideration when weighing the costs and benefits of retrofitting.

Flexible feeding, or gas production controlled by flexible feeding, proves to be economically more beneficial than continuous feeding as long as there are no additional costs, e. g. through the expansion of the feeding technology. In the case of a scheduled load transfer, focus is placed on gas storage since the gas storage capacity determines the transfer potential. Flexible feeding exhibits a cost-reducing effect in all scenarios.

From an economic perspective, the choice of gas storage plays a crucial role. Thus, when there is a modification to the operation of power generation plants, it is not expedient to choose an external DMGS unit if the existing biogas plant only needs slightly more gross storage capacity (e. g. less than 1,000 m³). In such a case step-fixed costs can be incurred that only produce additional revenue on a relatively marginal scale. This statement is tied to the spot market prices (2013 EPEX spot) used in the calculations and the potential for additional revenue connected with it. If the potential for additional revenue changes, the optimum of additional gas storage volumes will also change in the future.

The impact of the absolutely necessary gross storage requirements or the additional amount beyond existing gas storage capacities crucially depends on the different power generation schedules and the feeding regime. It has been shown that, in all scenarios, the need for additional gas storage volumes can be considerably reduced as a result of flexible feeding.

The $\Delta_{E\text{-}K}$ illustrated in Table 4 is influenced, above all, by the additional annual revenue on the EPEX spot. The highest additional costs for adding gas storage capacities are incurred with the weekly schedule and, to a smaller extent, with the daily schedule. The standard schedule does not require an expansion of the existing gas storage capacities in the modelling and thus produces no additional costs. When a daily or weekly schedule is used to generate power from biogas using CHP technology, the $\Delta_{E\text{-}K}$ is lower for continuous feeding than for flexible feeding. The largest $\Delta_{E\text{-}K}$ is achieved in the modelling when a weekly schedule is used in combination with flexible feeding.

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